

# **Official Transcript of Proceedings**

## **NUCLEAR REGULATORY COMMISSION**

Title: Advisory Committee on Reactor Safeguards  
593rd Meeting

Docket Number: (n/a)

Location: Rockville, Maryland

Date: Thursday, April 12, 2012

Work Order No.: NRC-1546

Pages 1-268

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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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593RD MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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THURSDAY

APRIL 12, 2012

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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., J. Sam  
Armijo, Chairman, presiding.

COMMITTEE MEMBERS:

J. SAM ARMIJO, Chairman

JOHN W. STETKAR, Vice Chairman

HAROLD B. RAY, Member-at-Large

SAID ABDEL-KHALIK, Member

CHARLES H. BROWN, JR. Member

MICHAEL L. CORRADINI, Member

DANA A. POWERS, Member

JOY REMPE, Member

1 MICHAEL T. RYAN, Member  
2 STEPHEN P. SCHULTZ, Member  
3 WILLIAM J. SHACK, Member  
4 JOHN D. SIEBER, Member  
5 GORDON R. SKILLMAN, Member

6 NRC STAFF PRESENT:

7 KATHY WEAVER, Designated Federal Official  
8 CHARLES ADER, NRO  
9 SURINDER ARORA, NRO/DNRL  
10 RAJENDER AULUCK, NRR/DLR  
11 ANGELA BUFORD, NRR  
12 MICHAEL CANOVA, NRO/DNRL  
13 ARTHUR CUNANAN, NRR  
14 MARK DELLIGATTI, NRR  
15 DONALD DUBE, NRO/DSRA  
16 HOSSEIN ESMAILI, RES/DSA  
17 RANI FRANOVICH, NRR  
18 RON FRUHM, NRR/DIRS  
19 MELANIE GALLOWAY, NRR  
20 MICHELLE HART, NRO/DSEA  
21 DON HELTON, RES  
22 ALLEN HISER, NRR/DLR  
23 MATTHEW HOMIACK, NRR  
24 SHANLAI LU, NRO/DSRA  
25 GEOFF MILLER, Region IV\*

1 DENNIS MOREY, NRR  
2 ANDREW T. MURPHY, RES/DE  
3 A.J. NOSEK, RES/DSA  
4 BO PHAM, NRR/DLR  
5 GREG PICK, Region IV\*  
6 JOSE PIRES, RES/DE  
7 WILLIAM RULAND, NRR  
8 MICHAEL SCOTT, RES  
9 JOHN SEGALA, NRO  
10 RAO TAMMARA, NRO/DSE  
11 KATIE WAGNER, RES  
12 JOHN WISE, NRR

13 ALSO PRESENT:

14 DALE ATKINSON, Energy Northwest  
15 BIFF BRADLEY, NEI  
16 MARK FINLEY, UniStar  
17 DON GREGOIRE, Energy Northwest  
18 ROBERT LEYSE\*  
19 STEVE RICHTER, Energy Northwest  
20 JOHN RUTKI, UniStar  
21 VI&CENT SOREL, UniStar  
22 SEBASTIEN THOMAS, UniStar  
23 JOHN TWOMEY, Energy Northwest

24 \*\*By telephone.  
25

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

8:30 a.m.

CHAIR ARMIJO: This is the first day of the 593rd meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the Committee will consider the following: Chapters of the Safety Evaluation Report, SER, with open items, associated with Calvert Cliffs Unit 3 combined license.

Two, spent fuels scoping study. Three, final safety evaluation report associated with the license renewal application of the Columbia Generating Station. Four, Risk-Informed Regulatory Framework for New Reactors, and five, Preparation of ACRS Reports.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Ms. Kathy Weaver is the designated federal official for the initial portion of the meeting. We've received no written comments from members of the public regarding today's sessions.

Mr. Bob Leyse has requested time to make an oral statement regarding the spent fuels scoping study. There will be a phone bridge line. To preclude interruption of the meeting, the phone will be placed in a listen-in mode during the presentations and committee discussion.

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

6           At this point, I'll turn it over to Dr.  
7           Powers, to lead us through the first session, right?

8           MEMBER POWERS: Sure.

9           CHAIR ARMIJO: Okay, great. He's accepted  
10          the assignment. That's good.

11          MEMBER POWERS: A joyful assignment.  
12          Joyful because of the people we get to work with on  
13          this particular project. As all of you are aware, we  
14          are conducting a review both of design certification  
15          for the U.S. EPR and for the referenced COLA, which is  
16          Calvert Cliffs Unit 3, and that the process that will  
17          proceeding the following involves the staff bringing  
18          to us their safety evaluation report with open items.

19          We view those open items are ones that  
20          they see, they and the applicants, see a route forward  
21          on resolution, and then we're looking at that  
22          material. Once we've looked at it moves to Phase 4  
23          where they will actually carry out the resolution of  
24          those open items.

25          So we do this somewhat piecemeal, and



1 today we're going to do some chapters for the  
2 referenced COLA. Those are the Chapter 6 on  
3 Engineering Safety Features, Chapter 7,  
4 Instrumentation and Controls, Chapter 15, Transient  
5 and Accident Analysis, and Chapter 18, Human Factors.

6 The procedure we're going to follow for  
7 this, staff is going to give us some opening comments,  
8 and then the applicant will describe how they have  
9 been addressed those chapters in the FSAR for the  
10 referenced COLA. In many cases, that's going to be,  
11 they've incorporated them by reference to the EPR  
12 certification.

13 With that, the intention then is that we  
14 will write a letter to the staff, commenting on those  
15 chapters for the referenced COLA. So unless there are  
16 any comments the Subcommittee or members would like to  
17 make at the beginning, I'll turn it over to Surinder  
18 Arora from the staff, to give us some opening  
19 comments.

20 MR. ARORA: Thank you, Dr. Powers. Good  
21 morning, everyone. My name is Surinder Arora, and I'm  
22 the lead project manager for Calvert Cliffs Nuclear  
23 Power Plant Unit 3 combined license application  
24 renewal project. We are here today, in front of the  
25 full Committee, to provide a briefing on four

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1 chapters, as Dr. Powers pointed out.

2 The chapters are 6, which is Engineer  
3 Safety Features, 7, Instrumental and Control, 15,  
4 Transient and Accident Analysis and 18, Human Factor  
5 Engineerings. These chapters have been previously  
6 presented to the ACRS Subcommittee. The full  
7 Committee meeting, this full Committee meeting is our  
8 second for this project.

9 Previously, about a year ago, on April  
10 7th, we had briefed the ACRS 582nd full Committee,  
11 under the chairmanship of Dr. Said Abdel-Khalik, when  
12 we presented nine complete chapters and one partial  
13 chapter.

14 A letter dated April 19th, 2011 was issued  
15 by the full Committee chairman, confirming that the  
16 Committee had no issues with these chapters that merit  
17 further consideration by the Committee.

18 The staff responded to that letter on May  
19 20th, 2011. Following the order of presentation, as  
20 is stated on the meeting agenda, UniStar will be  
21 briefing the Committee first. After Unistar's  
22 briefing, I will start with an overview of the status  
23 of the project, basically letting you know where we  
24 are in the review process for Calvert Cliffs'  
25 application.

1 I will also briefly go over the new  
2 strategy, how we perform the reviews in the office,  
3 which will then be followed by a brief summary of the  
4 review results for each chapter on the agenda today.

5 Once we've done these chapters, I will  
6 also touch upon the specific staff efforts, such as an  
7 independent evaluations and/or confirmatory analyses  
8 that staff performed to establish their conclusions.

9 If the Committee desires to discuss any  
10 specific details of the staff's review, I have a panel  
11 of staff members here in this room, who will be  
12 supporting me to discuss those details. With that, I  
13 would request Mr. Finley, Vice President of UniStar  
14 Energy, to introduce his team and start Unistar's  
15 presentation. Thank you.

16 MR. FINLEY: Thank you, Surinder. I am  
17 Mark Finley. I'm Senior Vice President of Regulatory  
18 Affairs and Engineering for UniStar. I appreciate the  
19 opportunity to be here in front of the full Committee  
20 of ACRS today to demonstrate we're still actively  
21 pursuing the combined license for Calvert Cliffs, and  
22 we appreciate the opportunity to move the process  
23 forward with the full Committee.

24 My background, I think most of you have  
25 met me here before, but my background is nuclear power

1 essentially all of my career. I've been with UniStar  
2 five years. Before that, Constellation Energy at the  
3 Calvert Cliffs site. Before that nuclear Navy and  
4 before that Naval Academy in terms of education. I do  
5 have a PE license in the state of Maryland.

6 I'm assisted today by Vincent Sorel,  
7 Director of Regulatory Affairs and Sebastien Thomas,  
8 our nuclear island engineering manager, and also Mr.  
9 John Rutki to help with the slides. Slide 2, I think,  
10 covers that introduction. Slide 3, this will be a  
11 high level presentation today. We'll focus on, as  
12 Surinder said, the four chapters 6, 7, 15 and 18,  
13 focus on the departures that we have, which I think  
14 you'll see are minor, and we can discuss open items  
15 that remain, and they're all on a good track for  
16 closure.

17 Slide 4. Just by way of context, UniStar  
18 is responsible for design of the Calvert Cliffs Unit  
19 3 site. The RCOLA is generally authored by AREVA and  
20 Bechtel. We don't have AREVA and Bechtel here today,  
21 given the high level nature of the presentation, but  
22 we can follow up on any questions that might need that  
23 level of detail, if necessary.

24 As we said, the focus will be the four  
25 chapters that we mentioned. This will give us 13-1/2

1 chapters completed in the Phase 2. We do have 5-1/2  
2 remaining. That half a chapter is a partial on  
3 Chapter 2. So we do have 5-1/2 chapters remaining for  
4 Phase 2, for completing that phase.

5 Slide 5, just an aerial photograph there  
6 of the Calvert Cliffs site. In the upper right-hand  
7 corner, that is a computer graphics of the new site.  
8 That's not actually -- I have this vision in my mind  
9 and it's on paper here, but it's still a dream at this  
10 point. But you can see a real picture of the existing  
11 site on the shores of the Chesapeake Bay.

12 There is a map to give you the geographic  
13 context on Slide 6. Located, as you see, about 40  
14 miles southeast of Washington, D.C., and tied to the  
15 PGM grid to the north through Baltimore, essentially  
16 the Waugh Chapel connection, and tied through Chalk  
17 Point through the grid in Virginia.

18 Slide 7, just a list of the chapters  
19 again, and Slide 8 the same way. As you can see,  
20 we'll discuss some of the departures and then a short  
21 summary for each chapter. The next slide, if you  
22 would, Slide 9.

23 So the first chapter is Chapter 6. So  
24 this is engineered safety features, and we do have one  
25 departure and exemption in this chapter, and it

1 relates to the toxic gas process.

2 So at Calvert Cliffs, we have analyzed all  
3 of the large quantities of toxic gases, both at the  
4 planned new site, Unit 3, and at the existing site,  
5 Units 1 and 2, and even in the worse scenario, none of  
6 the releases from those volumes of toxic gases reach  
7 a toxic level in the control room for the Unit 3 site.

8 Therefore, we don't need any automatic  
9 features to protect against releases of the toxic  
10 gases. So this is a departure at this time from the  
11 U.S. EPR design certification, as it requires  
12 automatic response to release of toxic gas.

13 So we've done the analysis, but the  
14 results are below what would be toxic for the  
15 operators and don't require any automatic type  
16 actions.

17 MEMBER SKILLMAN: Mark, let me ask why you  
18 wouldn't include that feature, simply because of the  
19 protection that it provides for what you don't know?

20 MR. FINLEY: I think that that's something  
21 that we could consider in the detailed design for the  
22 site. At this time, we've prepared the COLA without  
23 that protection, establishing the requirements. We  
24 will consider that in the detailed design phase.

25 Certainly, we'll have indication for some

1 of these releases on site. We just don't plan to have  
2 automatic features on the ventilation system in the  
3 main control room at this point.

4 MEMBER SKILLMAN: I think of examples  
5 where a huge grass fire has put down a blanket of  
6 particulate that's similar to fog, and if you're  
7 confined to the control room, even though you have  
8 excellent filtration, even though your control room  
9 and the load might be almost at a hospital  
10 ventilation quality, there can still be issues.

11 It just seems that with the magnitude of  
12 this investment, this is, in all candor, a 25 cent  
13 feature that protects your operators.

14 MR. FINLEY: I understand the point. We  
15 will still have the opportunity. Certainly, the  
16 operators, in the case of a fire, for example, the  
17 smoke, the operators would still have the opportunity.  
18 Obviously smoke is a visual thing, and they can take  
19 manual actions and place the ventilation system on  
20 recirculation manually.

21 I don't think that, you know, a fire or a  
22 smoke situation would be a challenge in that regard.  
23 So we take your point. We don't feel we need  
24 automatic features to address all of the toxic  
25 chemicals, but we do have the manual capability to

1 isolate the control room and protect the operators if  
2 we did have such an occurrence.

3 MEMBER SKILLMAN: Thank you, thank you.

4 MR. FINLEY: Next slide, John please.

5 Moving quickly through each chapter --

6 MEMBER POWERS: I would have taken -- when  
7 we discussed this in the Subcommittee, in my own mind,  
8 I took a different view on that. That view was that  
9 if I don't have to introduce complexity, don't  
10 introduce complexity. Complexity is a challenge.  
11 Just maintaining it, invoking it, and dealing with it  
12 when complexity doesn't work.

13 At least that was my thinking when you  
14 presented this material, and we spent a little while,  
15 because we were fairly suspect of your argument that  
16 there were no inadvertent instances when you could get  
17 toxic chemicals, since are right on a waterway and  
18 what-not.

19 So I wondered why you didn't follow my  
20 thinking on that.

21 MR. FINLEY: Well, I do follow your  
22 thinking, Dr. Powers. Certainly any additional  
23 instrumentation or automatic features in terms of  
24 damper operation and so forth, that does add  
25 complexity.



1           So I don't disagree with that. I also  
2           don't disagree with the main point that there's not a  
3           major expense involved in this, but we feel  
4           comfortable that the operation will have adequate  
5           protection, given their abilities to take manual  
6           action, if there is something beyond design basis, so  
7           that should come up.

8           MEMBER POWERS: Yeah. I mean certainly in  
9           the instance of a grass fire, manual actions are going  
10          to be odd. I mean grass fires develop somewhat slowly  
11          and they're pretty obvious when they occur. The  
12          automatic feature is the sudden event, the explosion  
13          of a barge or a truck or something like that. It's  
14          not common in your particular location.

15          MR. FINLEY: Well certainly we've analyzed  
16          those kinds of things, the traffic, in terms of the  
17          largest size of the truck on the nearest road, and  
18          then on the Bay traffic with the tankers. We've  
19          analyzed all of those occurrences.

20          CHAIR ARMIJO: Do the other units on the  
21          site, the operating units, have those automatic  
22          detection and isolation features for the control room?

23          MR. FINLEY: I'm not aware of any, Mr.  
24          Chairman. I'm not aware of any. I can't be certain  
25          about that. It's been a while since --

1 CHAIR ARMIJO: Can you find out? I just  
2 want to make sure it's consistent.

3 MEMBER POWERS: When we discussed it in  
4 Subcommittee, the answer was no.

5 MR. FINLEY: I'm not aware of any. I can  
6 confirm that. It's been a while since I've been  
7 there.

8 CHAIR ARMIJO: Okay. You get my points.  
9 If there were on the existing units, and you aren't  
10 going to put it on the new unit, you'd have  
11 inconsistency.

12 MEMBER POWERS: Again I've, for a variety  
13 of reasons, I've become very concerned about the issue  
14 of complexity, and even if there were, and I couldn't  
15 justify complexity. I would not put complexity in.

16 CHAIR ARMIJO: I don't disagree. I'm just  
17 saying that it looks, sounds, looks like a different  
18 --

19 MEMBER POWERS: And I wonder, it seems to  
20 me our ability to analyze complexity, especially as it  
21 interfaces with the human being, is still at a  
22 relatively primitive state.

23 One of the things that has been brought to  
24 my attention by my esteemed colleague, Mr. Skillman,  
25 is the issue of management complexity on three unit

1 sites, and I have in fact pursued that, to see if we  
2 can quantitatively assess the impact of management  
3 complexity, and my conclusion is that we cannot.

4 But it's a very real thing, and so I worry  
5 about it. Please continue. My soapbox is going to  
6 get weak here, if I keep pounding on it. I'll leave  
7 it alone.

8 MR. FINLEY: Slide 10 just shows a summary  
9 for Chapter 6, and again essentially we follow very  
10 closely the U.S. EPR FSAR for Chapter 6. We talked  
11 about the one departure exemption. There are no ASLB  
12 contentions related to this chapter.

13 There are two SER open items. One relates  
14 to the toxic gas response, and one also relates to  
15 analysis of an accident at the Unit 1 and 2 site, how  
16 that affects the dose at Unit 3. Those are in  
17 process. In fact, we've submitted our responses, and  
18 those are being analyzed by the staff.

19 There are three confirmatory items related  
20 to Chapter 3, and two of them relate to the codings  
21 problem, excuse me, codings program on site, and we've  
22 responded to those, and are on a track for resolution  
23 there, and one that relates to again codings, but the  
24 standards that would be applicable for a codings  
25 program on site. But not significant confirmatory

1 item.

2 MEMBER POWERS: And I will comment that  
3 the Subcommittee had raised an issue, a generic issue  
4 that it relates to, but it's not part of this  
5 particular licensing activity, on how the staff  
6 implements its coding standards, and in particular the  
7 synergism between thermal and regulated effects.

8 MEMBER SKILLMAN: Mark, I would like to  
9 ask one more question, and forgive the timing of my  
10 question, because I've not been deeply involved until  
11 recently. But in your Chapter 6A, in the document  
12 that we have for review, you have provided this  
13 wording:

14 "The extra borating system's designed to  
15 inject concentrated boron solution into the reactor  
16 coolant system at a rate sufficient to maintain some  
17 criticality during cool-down from any operational or  
18 anticipated transient, and is required to maintain  
19 subcriticality for the steam generator 2 rupture  
20 event."

21 That strong comment is somewhat softer in  
22 your Chapter 15. But I am curious about the  
23 requirement for the extra borating system on steam  
24 generator 2 rupture, and how thoroughly the words "is  
25 required" have been cemented into your thinking for

1 this unit.

2 MR. FINLEY: Okay. So this is a -- it's  
3 a generic item. It's essentially we're following  
4 AREVA completely in terms of the design certification  
5 and the design for responding both to a large break,  
6 small break LOCA and a tube rupture.

7 So this is not a site-specific departure  
8 or open item for the Calvert Cliffs site. I do  
9 understand that extra borating system is required for  
10 accident response. It will be safety-related.

11 MEMBER SKILLMAN: So this would be a  
12 comment that we should probably discuss with the  
13 design cert EPR AREVA-type folks.

14 MR. FINLEY: Yes, yes.

15 MEMBER SKILLMAN: Thank you, thank you.

16 MR. FINLEY: Okay. If no other questions  
17 on Chapter 6, we can move to Slide 11, and that just  
18 shows we're on to Chapter 7, and Chapter 7, of course,  
19 is Instrumentation and Controls, and again, we  
20 primarily follow the U.S. EPR design certification for  
21 Chapter 7, in terms of instrumentation and controls.

22 We do have some discussion, obviously, for  
23 instrumentation and controls on site-specific systems  
24 in this chapter, and also some programmatic-type  
25 discussion, in terms of programs that we will have at

1 a future date prior to operating the site.

2 One of those relates to the post-accident  
3 monitoring program, and the variables that we would  
4 have in our program at the site for maintaining  
5 instrumentation and indication in the control room,  
6 and specifically we've supplemented what's in the  
7 design certification regarding the UHS cooling tower  
8 basin, and regarding meteorological data. These are  
9 both site-specific type inputs that we've added to the  
10 list of PAM variables.

11 And Slide 13 just summarizes for chapters  
12 --

13 MEMBER ABDEL-KHALIK: Let me ask you a  
14 question about instrumentation. The EPR has a minimum  
15 DNBR reactor trip of based on in-core flux  
16 measurements and measurements of total core flow  
17 pressure and temperature. Can you tell me how that  
18 works if you ever have a mixed core, or have you given  
19 up the option of ever using a mixed core?

20 MR. FINLEY: Can you help me define what  
21 you mean by "mixed core"?

22 MEMBER ABDEL-KHALIK: A core that has  
23 fuels provided by different vendors.

24 MR. FINLEY: Okay. So again, this is  
25 really a generic question for AREVA, but I can tell

1 you from our experience in terms of an owner and  
2 oversight, we've made sure in our scope documentation  
3 for AREVA that we have the capability to have a mixed  
4 fuels from different vendors in the core, and the way  
5 that would be addressed would be in the safety  
6 analysis.

7 So in the safety analysis, you would set  
8 aside whatever margin is needed to address the  
9 differences in the fuel and the core, and assure that  
10 your set points are adjusted accordingly before you  
11 started up with that core. So we've made --

12 MEMBER ABDEL-KHALIK: But how was that  
13 assurance provided to you? Would that ever work if  
14 you have a mixed core?

15 MR. FINLEY: Certainly, it would work.  
16 It's no different, from my understanding, no different  
17 than the way it works now, in terms of operating  
18 plants changing fuel vendors. We get information  
19 related to the new fuel. We have information related  
20 to the --

21 MEMBER ABDEL-KHALIK: Not with an  
22 automatic calculator based on in-core flux  
23 measurements.

24 MR. FINLEY: I guess I don't understand  
25 the difference. In other words, there's still -- in

1 fact, with the in-core flux measurements, we get more  
2 detail than with ex-core instrumentation.

3 There's certain uncertainties that are  
4 calculated, and there's certain margin can be  
5 quantified, and those margins have to be demonstrated  
6 to bound any new deltas that are introduced by the  
7 different fuel tanks.

8 MEMBER ABDEL-KHALIK: But they're based on  
9 the assumption of uniform individual channel flow  
10 within the core, and if that's the case, I'm not sure  
11 how that would ever work in a mixed core.

12 MR. FINLEY: Okay. I must confess not  
13 being a safety analysis expert, and that really being  
14 a question for AREVA. I'll leave that one for them to  
15 --

16 MEMBER ABDEL-KHALIK: But still, I mean I  
17 raised the question because, you know, perhaps you've  
18 given up the option of ever using a mixed core.

19 MR. FINLEY: No, I can tell you we  
20 haven't, and we in fact have specified in our scope  
21 documents that we have the ability for changing the  
22 fuel, which means we need to have a mixed core. So we  
23 have that expectation, and frankly I don't see why  
24 that's not possible.

25 MEMBER ABDEL-KHALIK: So what you're



1 suggesting is that we bring that issue up in the  
2 design certification, or is that something that we --

3 MR. FINLEY: I think that is -- certainly,  
4 if we can't, we wouldn't go that direction and start-  
5 up. It would be more of a business decision, right?  
6 We would confirm, prior to loading that fuel, that the  
7 safety analysis supports it, or we wouldn't go that  
8 direction.

9 Our intention now is to go that direction,  
10 or to have the option to go that direction, and I feel  
11 that we have that option. In terms of the safety  
12 analysis and how it would address that condition,  
13 that's really a question more for AREVA than for us.

14 MEMBER ABDEL-KHALIK: Mr. Chairman, it's  
15 up to you, I guess, to decide how to proceed with  
16 this.

17 MEMBER POWERS: Well, I mean it's  
18 correctly stated. It's part of the design  
19 certification. I think it's been raised with AREVA.

20 MEMBER ABDEL-KHALIK: Right, but not with  
21 regard to the use of mixed cores.

22 MEMBER POWERS: Yeah. No, explicitly that  
23 question has been raised with AREVA.

24 MEMBER ABDEL-KHALIK: Right.

25 MEMBER POWERS: I've taken a note asking

1       them to address it. They'll be here in May. I mean  
2       it's been raised with them at Subcommittee.

3               I think the answer, at the time they gave  
4       it, was very close to what Mark Finley just said, and  
5       we asked them for some more information on it. So I  
6       guess it will be addressed. I mean it's part of the  
7       design, and they are the ones who have to address it.

8               MR. FINLEY: So in terms of a summary for  
9       Chapter 7, Slide 13 again, there are no departures or  
10      exemptions, no ASLB contentions. The three open items  
11      relate to providing some additional detail to the  
12      ultimate heat sink I&C system. We've had RAI from the  
13      staff that we are in the process of responding to.

14              Site-specific PAM variables is also an  
15      open item. We have an open item on calorimetric  
16      uncertainty, which is just to confirm that when we  
17      procure the instruments, that we incorporate  
18      uncertainty in those specific instruments that we  
19      procure, in the calculation of the calorimetric  
20      uncertainty. So --

21              MEMBER BROWN: When you say uncertainty in  
22      the instruments, you really mean the accuracy  
23      capability of those instruments in their monitoring?

24              MR. FINLEY: That's correct. So the  
25      accuracy of those instruments and the specific loop

1 when we design them.

2 MEMBER BROWN: Okay. I just wanted to  
3 make sure I'm shifting between analysis stuff and  
4 actual performance characteristics. Thank you.

5 MR. FINLEY: On slide, back to the general  
6 agenda again, Slide 14. So we'll move on to Chapter  
7 15 now. Chapter 15 is the safety analysis chapter.  
8 We do have one departure and exemption in this  
9 chapter, and it relates to the site-specific chi over  
10 q values.

11 You can see the details here. As it turns  
12 out for the Calvert Cliffs site, the zero to two hour  
13 chi over q for the low population zone is slightly  
14 greater than that which is in the U.S. EPR. U.S. EPR  
15 carries a value of 1.75 E to the minus 4, and for  
16 Calvert Cliffs, it was calculated as 2.15 E to the  
17 minus 4, so about a 25 percent delta there.

18 We've specifically addressed that through  
19 analysis for all of the releases from the Chapter 15  
20 events for the Calvert Cliffs site, using this site-  
21 specific chi over q. If you look at the next slide,  
22 we show the results for all of the analysis affected  
23 by this chi over q, and you can see for the Calvert  
24 Cliffs Unit 3 site, we're demonstrating significant  
25 margin to the acceptance criterion for each of these

1 events, even with the site-specific chi over q, which  
2 is a bit higher.

3 That's really the important issue for  
4 Chapter 15. We can move to Slide 17.

5 MEMBER REMPE: Before you leave, in  
6 Chapter 15, and I'm not sure if I should ask you or  
7 the staff, but you mentioned -- someone has used some  
8 shifting, time shifting of the chi over q values  
9 apparently, and is that -- could you just clarify  
10 what exactly was done?

11 MR. FINLEY: I'm going to ask you to ask  
12 the staff.

13 MEMBER REMPE: Okay.

14 MR. FINLEY: I'm not aware of time  
15 shifting in chi over q values.

16 MEMBER REMPE: Okay.

17 MR. FINLEY: Slide 17, just a summary of  
18 Chapter 15. So the one departure and exemption I  
19 mentioned. There are no SER open items or  
20 confirmatory items, and there are no ASLD contentions  
21 for Chapter 15.

22 And Slide 18, so we'll move on to Chapter  
23 18, which is on Slide 19, and the only real  
24 significant item here, and it's not significant from  
25 my point of view, is the departure that we've taken

1 that relates to the human performance monitoring  
2 program.

3 Essentially in Chapter 18, we incorporate  
4 by reference what's in the U.S. EPR FSAR. With  
5 respect to the human performance monitoring program we  
6 -- in our view, we've updated the program to  
7 incorporate some additional information available  
8 through INPO.

9 You see this INPO-09-011. It has some  
10 additional information about -- let's turn to operator  
11 aggregate index, that incorporates -- it's a metric  
12 that incorporates main control room deficiencies and  
13 operator work-arounds and other quantifiable measures  
14 that could affect operations, and it aggregates that  
15 into a metric that we've included in our program.

16 We've emphasized that we're going to use  
17 our Corrective Action Program in terms of monitoring  
18 issues that relate to human factors, and we won't have  
19 a separate HFE tracking program to monitor those kinds  
20 of issues. So two, would I say, slight departures  
21 from what's in the U.S. EPR FSAR.

22 MEMBER STETKAR: Mark, do you use that  
23 same monitoring process for Units 1 and 2 currently?

24 MR. FINLEY: I believe that's correct.  
25 I'd have to confirm that, not having been at the site

1 in a while. But I believe they have also updated  
2 their program to include the current INPO guidance.

3 MEMBER STETKAR: Again, in the sense of  
4 consistency, you know, among all three units at the  
5 site, especially when you're dealing with human  
6 performance and trying to measure that at a corporate  
7 level, or at a site management level.

8 MR. FINLEY: We'll do that. We'll do  
9 that.

10 MEMBER SKILLMAN: Mark, could you give us  
11 an idea of how strong your Corrective Action Program  
12 is?

13 MR. FINLEY: Certainly. We have a robust  
14 Corrective Action Program now, you know, for the  
15 functions we're performing now, and of course right  
16 now, our focus is design and licensing, and that's  
17 where we have our expertise and that's where our  
18 corrective action focus is.

19 We don't yet have this human performance  
20 monitoring program in place. So the aspects, in terms  
21 of indicators and trending with respect to this  
22 program, are not yet part of our Corrective Action  
23 Program.

24 But we have a fully functional Corrective  
25 Action Program for the functions we're performing now,

1 engineering and licensing primarily.

2 So, you know, we have periodic management  
3 review meetings of that program, and track indicators,  
4 just like you would for an operating plant. It's just  
5 the focus is a bit different.

6 MEMBER SKILLMAN: What is the highest  
7 level of senior management that participates in those  
8 meetings?

9 MR. FINLEY: Our chief nuclear officer, in  
10 fact, Greg Gibson, participates in those management  
11 review committees.

12 MEMBER SKILLMAN: Thank you, Mark.

13 MEMBER CORRADINI: Maybe this is the wrong  
14 time to ask it, and you guys can tell me to hold on.  
15 So is the senior management you're speaking about  
16 separate from 1 and 2 now? We're talking about a  
17 totally different management chain; is that correct?

18 MR. FINLEY: Yes, that's correct.

19 MEMBER CORRADINI: This is the wrong time  
20 to tell me, but I want to understand that, since  
21 they're co-located plants, or will be, I should say.

22 MR. FINLEY: That's correct. So as you  
23 recall, in 2010 essentially, Constellation EdF came to  
24 an agreement on the ownership of UniStar, and  
25 Constellation is no longer part of the ownership of

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1 UniStar. So we have a separate management structure  
2 from Constellation.

3 MEMBER CORRADINI: It's as if, from the  
4 standpoint of management, as if the other two plants  
5 are separate, don't exist down the road?

6 MR. FINLEY: That's correct, that's  
7 correct, that's correct.

8 MEMBER CORRADINI: Okay. So from a human  
9 performance standpoint again, if they're separate, how  
10 are you going to interact in case of safety-related  
11 issues between the two units? There's an agreement  
12 being formed, so that if something occurs one place,  
13 there's an immediate set of actions that have to be  
14 taken in the others? You know what I'm asking.

15 MR. FINLEY: Yes certainly. We expect in  
16 many areas, human performance I think is one, where  
17 we're going to have to cooperate certainly with the  
18 existing units.

19 So we'll have -- we don't have the program  
20 set up at this time, but we will have a program set up  
21 where we communicate on human performance issues that  
22 could affect the opposite site, and of course other  
23 matters as well. Certainly security.

24 MEMBER CORRADINI: I just wanted to make  
25 sure I had it correct in my head. That's all. That's



1 all I wanted.

2 MEMBER RYAN: Mark, I guess on emergency  
3 response and all those kind of things require that  
4 same --

5 MR. FINLEY: Exactly. Emergency response  
6 even moreso, given the current recommendations with  
7 Fukushima, yes.

8 MEMBER CORRADINI: A work in progress  
9 would be the best way to describe it at this point?

10 MR. FINLEY: That would be a good way,  
11 yes.

12 MEMBER CORRADINI: Thank you.

13 MEMBER SCHULTZ: So Mark, just to back up  
14 a moment with regard to the explanation of the  
15 connection between the two sites, the information that  
16 was provided related to Chapter 15, the chi over q  
17 values, are those from the Calvert Cliffs site? Is it  
18 uniform between the two units existing now and what  
19 you've described here?

20 MR. FINLEY: Yes. So the data that was  
21 used to calculate these chi over qs came in part from  
22 the meteorological tower for the existing units.  
23 Obviously, given the close proximity of the existing  
24 units to the new site, we think that's well indicative  
25 of the chi over q that we'll have for the new site.

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1                   So in that sense, it is a calculation of  
2                   chi over q for the existing units.

3                   MEMBER ABDEL-KHALIK: So these units will  
4                   have a completely separate switchyard?

5                   MR. FINLEY: So the question on the  
6                   switchyard. So we will have a separate switchyard.  
7                   However, our intention is to have two tie lines to the  
8                   existing switchyard, and in addition, we'll have two  
9                   separate lines that essentially bypass the existing  
10                  switchyard, to tie directly into the Unit 3  
11                  switchyard.

12                  So multiple interconnections, if you will.  
13                  We will be connected to the existing switchyard.

14                  MEMBER ABDEL-KHALIK: So that sort of  
15                  pertains to Mike's question about the connection with  
16                  the existing units?

17                  MR. FINLEY: Certainly, certainly. That's  
18                  one, another area. Any operations in the switch yards  
19                  that could affect one site or the other, we would have  
20                  to have some overlaps.

21                  MEMBER ABDEL-KHALIK: We'll see you about  
22                  that.

23                  MR. FINLEY: Okay, and summary for Chapter  
24                  18 is on Slide 20, and I talked about the one  
25                  departure. There are no open items. We've responded

1 to all the RAIs. There are two confirmatory items.

2 One relates to guidance for writing  
3 procedures in accordance with human factors  
4 engineering criteria. We've responded to that, and  
5 one relates to this departure that I talked about  
6 today already.

7 That, I think, brings me to the close of  
8 my presentation. Slide 22, just to summarize. There  
9 are no ASLB contentions with any of these chapters.  
10 We talked about the three departures, and two of those  
11 are exemptions as well.

12 We have incorporated the confirmatory  
13 items in our most recent Revision 8, submitted at the  
14 end of March, and we've responded to the staff on four  
15 of the five open items.

16 The one remaining open item is the details  
17 of the instrumentation and controls system for the UHS  
18 in Chapter 7. I talked about that. So as of today,  
19 we would have 13-1/2 of the 19 chapters for the  
20 Calvert Cliffs Unit 3 FSAR completed through Phase 3.  
21 Any other questions for me?

22 MEMBER SKILLMAN: Yes sir. A brief  
23 question. Let me get my thinking cap on here.  
24 There's a piece of Chapter 6 that's still out there,  
25 and I'm curious. 6.2.1 and 6.2.2, containment

1 function design and containment heat removal systems.  
2 When are those up for review please?

3 MR. FINLEY: I think this would again be  
4 for the design certification and AREVA.

5 (Simultaneous speaking.)

6 MR. FINLEY: Yes, for us.

7 MEMBER SKILLMAN: They're still open.  
8 Thank you, understand. Thank you.

9 MR. FINLEY: Anything else for me? Okay,  
10 thank you very much.

11 MEMBER POWERS: Thank you.

12 MEMBER ABDEL-KHALIK: I guess  
13 philosophically, when questions arise during these  
14 discussions, that the judgment is made that they  
15 pertain to the design certification. Does the staff  
16 carry over these questions, or do we just rely on the  
17 record, that the questions are conveyed to the design  
18 certification?

19 MEMBER POWERS: I am sure that staff pays  
20 attention to them. But should they not, Ms. Weaver  
21 and I assure that they are communicated when they  
22 arise in discussions, when they belong to the DCD.

23 MEMBER ABDEL-KHALIK: I understand that  
24 this is the practicality of it, but shouldn't it be  
25 some more formal way of connecting questions that

1 arise during the discussions of the COLA, that are  
2 judged to be design certification-related, rather than  
3 relying on ACRS essentially transmitting the questions  
4 to the design certification applicant?

5 MEMBER POWERS: You're asking a question  
6 of cosmological and philosophical nature. I have no  
7 idea. All I do is assure that the questions get  
8 passed on to the applicant, and we usually get an  
9 answer.

10 MEMBER ABDEL-KHALIK: Good, thank you.

11 MEMBER POWERS: And usually that's not the  
12 problem. Usually, the problem is that the DCD  
13 applicant comes to us and says can you explain better  
14 what this question is, because we've identified it on  
15 the transcript?

16 I looked for confirmation at from Ms.  
17 Weaver, and I think that's true, that they tend to be  
18 fairly aggressive identifying those questions and  
19 asking us what they are, and I tend to be very reliant  
20 on Ms. Weaver helping me out on that.

21 I mean all I can say is it seems to work  
22 well. Whether there needs to be some formality, I'm  
23 not wild about formality. I'm wild about getting  
24 answers. Surinder. More interesting to me is when we  
25 identify things that need to be recognized in the

1 inspection and enforcement, especially during  
2 construction, how those get transferred on, because  
3 there's a gap in our span of control there.

4 MEMBER CORRADINI: "Our" meaning "us"?

5 MEMBER POWERS: Us, and we have at the  
6 Subcommittee raised that exact question. Is there a  
7 formal mechanism? The staff assures us that they have  
8 one, when they identify them in the DCD, that they  
9 flag those, so that the inspection people pay  
10 attention to those areas.

11 MEMBER CORRADINI: But that's more generic  
12 that we've identified for all groups.

13 MEMBER POWERS: I mean episodically,  
14 thinking of the last Subcommittee meeting, and you  
15 know, I mean I take them at their word, that yeah,  
16 they flag them and what-not. I have not gone back and  
17 looked.

18 MEMBER CORRADINI: I meant your point was  
19 after the DC and COLA or the COL is done, then there's  
20 this generic gap that --

21 MEMBER POWERS: Yeah, yeah. I mean it's  
22 good they're a different body of people looking at  
23 those, and you know, I make no assurance that that  
24 body from the ACRS would raise the same question. But  
25 the staff says that they definitely flag them, and

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1       there's a communication there. I cannot say that I've  
2       gone back and identified it.

3               But that's where, yeah, I think I would  
4       welcome a little more formality there, just because  
5       there is a gap. Here, between the RCOLA and the DCD,  
6       it's so coupled that I'm not too concerned about  
7       formality there.

8               MEMBER BROWN: Related to Chapter 7 DCD,  
9       I mean I had -- we had two open items on the I&C, and  
10      we incorporated those into your letter. So they are  
11      explicitly stated in the paragraph in the letter.

12              So those are -- I mean that is a formal --  
13      for those items. I'm not speaking to the other one,  
14      but that is a mechanism when they get cranked into our  
15      letter, from that standpoint.

16              MEMBER ABDEL-KHALIK: My concern is the  
17      other direction.

18              MEMBER BROWN: Yeah. No, I understand  
19      that. I didn't repeat them for the COL, because we  
20      already had -- they were really AREVA-type items.

21              MEMBER POWERS: I mean, there's nothing  
22      they can do about it except tell us the same thing  
23      louder. Surinder.

24              MR. ARORA: Thank you, Dr. Powers. Good  
25      morning again. As I previously mentioned, we'll start

1 our presentation with a general presentation, giving  
2 you the status of projects. Mike, we can move to --

3 My first slide here shows in chronological  
4 order when the COLA revisions were submitted by  
5 UniStar for staff's review. As shown in the slide,  
6 the Calvert Cliffs COL application was received in two  
7 parts, and several supplements, starting with initial  
8 submittal of Part 1 in July 2007, which was followed  
9 by Revision 1 of Part 1 and along with that was  
10 submitted Part 2, which completed the initial  
11 application.

12 That was in March 2008. Part 2 was  
13 accepted for review and the application was docketed  
14 as Docket No. 52-016 in June of 2008. Several updates  
15 were submitted after the submittal of the initial  
16 application, and the latest revision that we have  
17 today is Revision 8, which came to us on March 27th  
18 this year, very recently.

19 The COLA reviews are being performed  
20 concurrently with the EPR design certification  
21 application review. As I previously stated, the staff  
22 has completed Phase 2 reviews on nine full chapters  
23 and one partial chapter. The partial chapter was  
24 Chapter 2, which remains to be presented. The two  
25 parts are 2.4 and 2.5 sections.



1           As I will show on the next slide, the  
2 Phase 2 reviews, they comprise of production of the  
3 safety evaluation with open items identified. Next  
4 one. This slide identifies the six phases of staff's  
5 review process. This applies to any chapter in the  
6 application. We are currently working in Phases 2, 3  
7 and 4 on various chapters of the review process.

8           The target dates, which are the phase  
9 completion milestone dates, are being reevaluated for  
10 several phases, as stated on the slide. The reason  
11 for the reevaluation is that we recently received a  
12 response schedule for all the RAIs which are pending,  
13 a letter UniStar provided on February 21 this year.

14           We are reviewing our schedules to  
15 reestablish these milestones, based on the dates that  
16 have been provided to us. Staff is planning to issue  
17 a schedule letter providing all those milestone dates  
18 by end of this month.

19           Next slide. With that, I will go over our  
20 review strategy. Basically, this slide provides major  
21 characteristics of our review process in general. The  
22 process starts even before the combined license  
23 application is received by the staff from the  
24 applicant.

25           The pre-application activities involve one

1 or more public meetings near the proposed site, to  
2 make the public and the neighboring areas aware of the  
3 applicant's intent to build a new nuclear power plant,  
4 and to explain the NRC's review process after the  
5 application is received.

6 The pre-application activities also  
7 include interactions with the applicant as needed, for  
8 planning to reviews by the staff. After receiving the  
9 application, the staff performs a review of the  
10 contents of the application for its completeness, and  
11 issues an acceptance letter conveying the decision to  
12 docket the application and starts its review.

13 As we all know, the Part 52 licensing  
14 process allows COL applicants to incorporate by  
15 reference the sections of the design certification  
16 application. This streamlines the review process by  
17 eliminating duplicacy and redundancy in review.

18 The Calvert Cliffs Unit 3 COL application  
19 took advantage of this provision, because of which  
20 several sections of the FSAR incorporate by reference  
21 the EPR DC FSAR sections.

22 The EPR DC application is concurrently  
23 being reviewed under Docket No. 52-020. The staff's  
24 review of the COL FSAR for the chapters all sections  
25 which incorporate U.S. EPR FSAR by reference, ensures

1 that the combination of the information incorporated  
2 by reference from the DC FSAR and the site-specific  
3 information included in the COL FSAR represents the  
4 complete scope of the information relating to the  
5 specific review topic.

6 In most cases, same technical staff  
7 reviews the DC and COL applications. This approach  
8 helps in keeping the review consistency between the  
9 two applications. A generic RAI applicable to all  
10 COLA chapters which have IBR information has been  
11 created, and has been issued for tracking the open  
12 item pertinent to the concurrent review process.

13 This will assure that the final revision  
14 of the EPR FSAR is fully complied with when we close  
15 this RAI. This open item will apply to all COLA  
16 chapters, as I said, and will be closed after the  
17 design certification is complete.

18 During its review, the staff uses several  
19 tools like eRAI system to track the requests for  
20 additional items, teleconferences with the applicant  
21 and public meetings as required, to request and  
22 discuss any additional information that staff may  
23 need.

24 Staff also conducts audits to review any  
25 supporting information or reference documentation,

1 which are not included with the application but are  
2 referenced in the application. For that, they conduct  
3 the audits and look at that documentation, review it  
4 at site.

5 Before bringing the issue with open items  
6 to the Subcommittee, it is assured that all the issues  
7 are either resolved and closed, or there exists a  
8 clear resolution path forward, in which case an open  
9 item is created to track the issue until it is finally  
10 resolved and closed.

11 The chapter being reviewed remains in  
12 Phase 2 until all staff's RAIs are satisfactorily  
13 answered, and any outstanding issues are fully  
14 resolved, or we have a clear path forward, in which  
15 case we'll create an open item. So that's basically  
16 our review strategy, how we conduct reviews on any  
17 application.

18 Next slide, Mike. With that, I will start  
19 now presentation on each of the chapters which are on  
20 today's agenda. As stated in this slide, we had  
21 several sections of Chapter 6, namely 6.2.1, 6.2.2 and  
22 6.3, which were excluded from presentation to the  
23 Subcommittee, because these particular sections were  
24 IBR sections. They were incorporated by reference  
25 into the COLA.

1                   However, they were not fully resolved or  
2                   reviewed in the DC space of the application. So we  
3                   didn't put in those sections and we will be bringing  
4                   those in the Phase 4, after Phase 4 ACRS meeting.

5                   MEMBER SKILLMAN: Surinder, let me ask  
6                   this.

7                   MR. ARORA: Sure.

8                   MEMBER SKILLMAN: Just from an optics  
9                   perspective, why is it okay to IBR a critical  
10                  technical chapter that is not yet fully reviewed? Why  
11                  is it acceptable to IBR an important technical chapter  
12                  that is not fully reviewed?

13                  MR. ARORA: I think my understanding of  
14                  that would be the regulation allows that they can  
15                  incorporate sections of the design certification into  
16                  COL application, and the section is there in the EPR  
17                  design certification. However, we may be having some  
18                  questions or RAIs which are pending at this time.

19                  So we don't close that item in the COLA  
20                  environment, because if it is not resolved in the DC,  
21                  we will not declare victory in COL space.

22                  MEMBER SKILLMAN: I think I understand, if  
23                  you will, the acceptability of doing that the way Part  
24                  52 is written. So I respect your answer.

25                  But it seems to me to be somewhat of a

1       perversion to say we're going to IBR this chapter,  
2       even though the chapter's not been hammered out and  
3       slugged out and vetted and reviewed and approved and  
4       all the figures, all the tables and all of the  
5       calculations that back up the conclusions are by golly  
6       complete and known to be accurate.

7               It just seems like there's a cog in this  
8       mechanism that is not as strong as it needs to be.

9               MEMBER CORRADINI: Can I ask a question?  
10      I guess I want to clarify, because the only reason I'm  
11      listening closely to this is because we're doing this  
12      with other design centers. Is your point that because  
13      it's still being held in abeyance in the  
14      certification, that associated chapter in the COL  
15      should be left open? Is that your point?

16              MEMBER SKILLMAN: Yes sir. That's this  
17      man's opinion, yes sir.

18              MEMBER CORRADINI: But I guess my only  
19      reflection back is at least in my experience, staff is  
20      well aware of what's going on back in the world of the  
21      DCD, and doesn't bless the associated chapter here, no  
22      matter whether it's -- even though it says IBR. I  
23      guess that was my interpretation of how staff behaves  
24      like that.

25              MEMBER POWERS: Yeah, and there is a

1 subsequent review of this, and in that subsequent  
2 review, this chapter will be completed, and the staff  
3 will look at it. If the -- I mean the person at risk  
4 here is the applicant.

5 MEMBER SKILLMAN: Yes. It just seems to  
6 me to be peculiar we would say we're going to IBR this  
7 chapter, but we're not quite sure what it says yet.

8 MR. ARORA: I think the problem is because  
9 we are having comprehensive review of EPR design  
10 certification and COLA at the same time. It's a valid  
11 review. If DC would have only being certified or  
12 designed, then you will not be asking that question.

13 MEMBER SKILLMAN: That is accurate, and I  
14 understand that.

15 MR. ARORA: But we are not there yet. So  
16 they are being concurrently reviewed, so we are making  
17 sure that we are using the same staff members to  
18 review both applications, so there is a continuity  
19 between the two applications.

20 MEMBER STETKAR: And if this were a  
21 meeting on, at Phase 5 of the review, there would be  
22 a problem.

23 MEMBER POWERS: There will be a problem.

24 MEMBER STETKAR: But it's not yet. Thank  
25 you.

1 MR. ARORA: Summary of Chapter 6. Most  
2 sections of the chapter were incorporated by  
3 reference, and therefore the bulk of the review of  
4 those sections was performed under design  
5 certification effort.

6 There were still ten questions, RAI  
7 questions which were issued, requesting additional  
8 information from the applicant, and most of the  
9 questions, six of ten were in the area of  
10 habitability.

11 During the review of Section 2.2, the  
12 staff identified that one chemical, hydrochloric acid,  
13 may have the potential to challenge the control room  
14 habitability. To evaluate this, the staff performed  
15 an independent calculation to confirm that no design  
16 basis toxic gas threat exists.

17 In addition, they provided that input to  
18 6.4 reviewers, to perform further analysis in their  
19 chapter, and Chapter 6.4 reviewers performed a  
20 confirmatory analysis for this chemical, along with  
21 other chemicals, for control room habitability, using  
22 NRC HABIT code, to verify that the control room  
23 hazardous chemical concentrations were well below the  
24 IDLH limits.

25 So that was staff's initiative, doing the



1 confirmatory analysis in this case.

2 MEMBER STETKAR: Surinder, can you help  
3 me? We're pretty good on time here, and this is kind  
4 of a self-education question, so bear with me. How,  
5 going forward through the life of this facility, 40  
6 years, 60 years, however long it's there, what process  
7 is in place?

8 For example, suppose chemical company X  
9 decides to build the world's largest source of toxic  
10 gas directly upwind of this site on their property,  
11 you know, ten years in the future? What process then  
12 assures that the design is reexamined, for perhaps the  
13 need for automatic isolation?

14 MR. ARORA: This will be when the plant is  
15 already in operation?

16 MEMBER STETKAR: Yes, yes.

17 MR. ARORA: It's constructed, built and  
18 operating?

19 MEMBER STETKAR: That's why I used ten  
20 years in the future, because we're at zero operation  
21 now. Ten years after whenever the plant might start.  
22 So that a new, essentially a new hazard is introduced,  
23 circumstances beyond the licensee's control, because  
24 it's off site.

25 MR. ARORA: Right. Well, I appreciate the

1 concern and I have a technical staff who has  
2 volunteered --

3 MR. TAMMARA: My name is Rao Tammara. I  
4 do the evaluations of these external factors in  
5 Chapter 2. So in Chapter 2, we cover for the new  
6 facility, all the existing facilities within five  
7 miles of the site. Say for example into the future,  
8 if this new facility happens to come into being, that  
9 facility has to be, get licensed by the locality,  
10 state or county or whatever, whichever. If it is a  
11 new facility, that has to go through the licensing  
12 process or whatever.

13 So in that case, that has to be evaluated  
14 what would be the impacts of that facility on the  
15 nearby facilities? Like an example, Coal Point at  
16 Calvert Cliffs, we have a natural gas storage  
17 facility, that has been there in existence. But they  
18 applied for an expansion, and in the process of that  
19 expansion, Maryland Natural Resources and the state  
20 has to do the expansion license.

21 In that process, they evaluated what would  
22 be the impacts of the expansion on Calvert Cliffs, and  
23 also Calvert Cliffs is aware of the project, and that  
24 NRC's regulations for leading to the new facility,  
25 proposed facility, Unit 3.

1           So to answer you the question, if it is a  
2   new facility, NRC doesn't have a regulatory  
3   requirement to control what it affects, I mean, from  
4   the regulatory point of view. However, it is the  
5   other licensing experts will take care, one thing, and  
6   if there is a big, significant difference that is  
7   anticipated to impacting the plant, of course, the  
8   applicant will naturally evaluate the total processes.

9           Any public can put application allegation  
10   through that process. NRC might well reevaluate what  
11   would be the -- or force the applicant to make an  
12   evaluation, what is the impact? Did you look at it?  
13   So these are the avenues available to answer. But it  
14   is a regulatory process. I mean that answer can --

15           MEMBER STETKAR: Okay, thanks. That at  
16   least helps me to understand how the process works in  
17   practice.

18           (Simultaneous speaking.)

19           MR. ARORA: Thank you, Rao. Other thing  
20   John, I would like to add to that is at this time, we  
21   are basing our reviews on what we have been provided.

22           So in that COLA application, what were  
23   additional toxic gas sources that they have given to  
24   us, we are evaluating those and basing our reviews on  
25   that. If something is added later --

1 MEMBER STETKAR: No, I understand that.  
2 I was asking -- it's not really a question that's  
3 relevant to this particular proceeding. It was, given  
4 the fact that we had a little bit of extra time, self-  
5 education. Thank you.

6 MR. ARORA: Thank you.

7 MEMBER BROWN: Yes. I wanted to -- you  
8 said you evaluate the information given to you for  
9 that site. I take that to mean you don't  
10 independently look to make sure they gave you all the  
11 information, or you do do that?

12 MR. ARORA: No, we do that -- we will. We  
13 do ask questions. We send out --

14 (Simultaneous speaking.)

15 MEMBER BROWN: I wanted to make sure.

16 MR. ARORA: No. What I said is we are  
17 performing the review of the application that has been  
18 turned in to staff.

19 MEMBER BROWN: Yeah I know, but you don't  
20 -- that doesn't exclude you from ensuring that they  
21 gave you all the relevant or correct information.

22 MR. ARORA: But at the same time, we can't  
23 foresee the future, what's coming up in ten years.

24 MEMBER BROWN: Not future. I'm talking  
25 about right now, and if they missed a facility that

1 you think should be included --

2 MR. ARORA: Sure. We will definitely pick  
3 that up.

4 MEMBER BROWN: Okay. I just wanted to  
5 ensure that there weren't blinders here. I didn't  
6 think there were. I just wanted to hear you say it,  
7 that's all.

8 MR. CANOVA: I'm Mike Canova. I'm  
9 supporting him today, but I'm actually the Bell Bend  
10 lead also. Rao does audits when we do these reviews,  
11 and goes out and surveys the area, to make sure  
12 nothing's been excluded from the application.

13 MEMBER BROWN: Okay, thank you.

14 MEMBER SCHULTZ: If the basis for the  
15 license is the existing facilities, then a new  
16 facility ought to go into the licensee's Corrective  
17 Action Program for evaluation.

18 MALE PARTICIPANT: Right.

19 MEMBER CORRADINI: You would think so, for  
20 self-preservation if nothing else.

21 MR. CANOVA: I believe it would also  
22 require an environmental impact statement, which would  
23 also bring out the same issues.

24 MEMBER SKILLMAN: Well, part of this  
25 discussion alarms me. I'll give you an example. I

1 know of one site where the potential for toxic gas or  
2 gas cloud explosion was fairly well explored, and the  
3 answer was you can't have toxic gas. You just won't  
4 have it.

5 But if you put on your hard hat and safety  
6 glasses and walked out onto the property, there was an  
7 18-wheeler nitrogen truck delivering not really a  
8 toxic gas but a suffocant, about 35 or 40 feet or 50  
9 feet from the primary air intake for the control room.

10 That kind of bypassed everybody's field  
11 review. Taking on nitrogen is a normal process. It's  
12 used for a lot of applications at a nuclear power  
13 plant, and here was a well-intending gentlemen backing  
14 in his 18-wheeler, and he ran over some pipes and  
15 guess what? We had a nitrogen release.

16 The distance to the air intake is about as  
17 far as from here to the corner office, not very far,  
18 maybe 80 feet. Oh gee whiz, is that different than  
19 what we thought? Well you know what? It really was.  
20 It wasn't toxic, but it was an event that could have  
21 had significance had the amount of gas that was  
22 released been great.

23 MEMBER POWERS: But it did not escape our  
24 attention in the review of this material, because we  
25 specifically looked at where gas deliveries were

1 taking place.

2 MEMBER SKILLMAN: Good, all right. A fine  
3 point. Some of this stuff is very subtle, and it's  
4 easy to march over it when one might need to be a  
5 little more circumspect when reviewing this  
6 information. Thank you.

7 MR. ARORA: Thank you. Continuing with  
8 Chapter 6, based on the RAI responses of the ten RAI  
9 questions that were sent by the staff, all questions  
10 were resolved and there were only two open items left  
11 to be resolved when the chapter was last presented to  
12 the Subcommittee on 5th of April last year. Both RAIs  
13 related to the open items have already been answered  
14 by UniStar, and staff is reviewing the responses  
15 currently. We will be closing those open items in the  
16 Phase 4 effort.

17 Next one. Summary of Chapter 7,  
18 Instrumentation and Control. Again, most of the  
19 sections of these chapters are also incorporated by  
20 reference, but there was a lot of effort put in by the  
21 staff to review the sections interactions between the  
22 APR design certification and COLA.

23 A total of six requests for additional  
24 information were issued in this case. Three of the  
25 six questions were resolved fully and closed. Based

1 on the responses provided by UniStar, the other three  
2 were identified as open items when the chapter was  
3 last presented in November to the Subcommittee.

4 In the first question of the three open  
5 items, the staff had asked applicant to provide  
6 specific I&C instrumentation for certain site-specific  
7 systems, such as ultimate heat sink system, makeup  
8 water, ultimate heat sink makeup water intake  
9 structure, ventilation system, etcetera. The question  
10 has not yet been responded by UniStar, and we are  
11 waiting for their response. I think it's scheduled to  
12 be coming to us some time in July.

13 The second question that staff had asked  
14 was in Section 7.5 of the FSAR, and it addresses a new  
15 COLA item that was added by AREVA, relative to the  
16 site-specific and monitoring variables. UniStar has  
17 provided a response to this question a few days ago,  
18 and it is currently in review by our staff. If found  
19 acceptable, this item will be closed.

20 The last RAI related to the open items  
21 requested UniStar to update Section 7.7 of COLA FSAR,  
22 to address a COL action item pertinent to primary  
23 power calorimetric uncertainty. UniStar had provided  
24 a response to this RAI, which was found acceptable by  
25 staff. This open item will therefore be closed during



1 the Phase 4 review effort.

2 As you see, the staff is asking questions  
3 relative to the inconsistencies between EPR and EPR DC  
4 and COLA applications. This is a good example of  
5 where we have taken advantage of using the same  
6 technical reviewers for both applications.

7 Next chapter. Chapter 15. A lot of  
8 sections of this chapter were IBR, with no departure  
9 and exemptions from the DC. Generally, the  
10 supplementary site-specific information provided in  
11 the COLA was the focus of staff's review. The review  
12 resulted in only one RAI, which was adequately  
13 addressed by the applicant.

14 Based on the information provided in the  
15 RAI response, there was no open item identified for  
16 this chapter. However, in Section 15.0.3, the  
17 applicant had taken a departure and exemption from the  
18 U.S. EPR FSAR, which the applicant also discussed, and  
19 this was to use site characteristic accident chi over  
20 qs to calculate site-specific dose values at LPZ.

21 The staff performed an independent DBA  
22 dose analysis to verify the results of the applicant  
23 site-specific analysis reported in the FSAR. To  
24 perform this analysis, the staff used the computer  
25 code models that were developed for completion of the

1 U.S. EPR DC review, and they used the site-specific  
2 chi over qs to calculate the site-specific doses for  
3 all DBAs at LPZ.

4 The results were found acceptable, and I  
5 have the staff's report here if any member of the  
6 Committee has any additional questions or  
7 clarification on that analysis.

8 MEMBER REMPE: So again, I was looking at,  
9 let's see, page 15.6, and it references that they  
10 actually did time shifting of the chi over q values.  
11 I assume that means they took the higher one, and when  
12 the release was high, they applied it. But I was  
13 surprised that they did that, actually the applicant  
14 did that, and then you checked them?

15 MS. HART: That is correct. In fact, this  
16 is Michelle Hart. I'm in the Radiation Protection  
17 and Dose Analysis Branch, and I did that review for  
18 both the DC and for this COL. The DC, AREVA did that  
19 in the DC.

20 They time-shifted the LPZ, and it is  
21 correct. Your interpretation of what that means is  
22 you take the zero to two hour chi over q for the LPZ  
23 and apply that during the worse release time.

24 Then you put what would have been during  
25 that time before and after, and then continue with the

1 different dispersion characteristics. So you're  
2 having the least dispersion during the time that you  
3 have the worse release. I asked UniStar if they did  
4 that for Calvert as well, and they did. That was in,  
5 also in relation to the question because they only had  
6 the one chi over q for the 0 to 2 hour period, that  
7 was higher than the DCD values.

8 Did they use just that value, or did they  
9 use all of the site-specific values, and they used all  
10 of the site-specific values. So that's, the reason I  
11 had to ask that question is because their LPZ, site-  
12 specific doses were actually lower than the DC values.

13 So if you had a higher chi over q, that  
14 didn't make sense on the face of it. But yes, it was  
15 just for that one time period that it was slightly  
16 higher, and when you apply all of them, because the  
17 rest of them were lower than DC, the overall dose was  
18 lower in most cases.

19 MEMBER REMPE: Okay, thanks.

20 MR. ARORA: Thank you, Michelle. It may  
21 also be noted that the rest of the DBA doses results  
22 for exclusionary boundary, control room and DFC doses,  
23 they were all incorporated by reference. The staff  
24 found that these were acceptable, because the Calvert  
25 site characteristic chi over qs were lower than those

1 values which were used as site parameters in U.S. EPR.

2 Next chapter, Chapter 18. The only branch  
3 that was involved with the review of this chapter was  
4 the operator licensing and human performance branch.  
5 Only two RAI questions requesting additional  
6 information from the applicant were issued.

7 One question was on the procedure  
8 development section of the application, and the other  
9 on the human performance monitoring. Both these RAIs  
10 were answered very promptly by the applicant, and the  
11 staff was fully satisfied with the responses received.

12 The review was completed without any open  
13 item being identified. The staff's review ensured  
14 that the HFE design responsibility for emergency  
15 operation facility was specifically stated in the COL  
16 application, and that the application provided a  
17 statement of standards that would be met.

18 All COL information items identified in  
19 the EPR design certification were addressed properly  
20 in the COLA. That was also made sure by the staff  
21 during their review. There was an ITAAC for  
22 verification requirement, to verify that the staffing  
23 levels derived from task and staffing analysis, they  
24 remain bounded by the regulation.

25 So those were the certain salient items

1 that staff looked at during their review, and there  
2 was no open items, as I said. All the responses were  
3 satisfactory. That was my last chapter presentation,  
4 okay.

5 We have staff representation here for  
6 Chapter 18 also, if any member has any additional  
7 questions.

8 MEMBER POWERS: Any other questions to  
9 present to the presentation? I would just comment  
10 that as to Aurora's earlier slide, he put down a  
11 simple bullet that said "phase discipline." That is  
12 a more significant comment than you might think from  
13 a simple line.

14 The only reason this kind of piecemeal  
15 review works is because both staff and applicant  
16 exhibit a very strong phase discipline, and I thank  
17 them very much for that. With that, Mr. Chairman, I  
18 think we're done.

19 CHAIR ARMIJO: Thank you very much.

20 MEMBER POWERS: John, did you have a  
21 comment you wanted to make?

22 MR. SEGALA: Yeah. This is John Segala  
23 from Licensing Branch 1. I'm a branch chief. We have  
24 a reviewer here that could talk a little bit about the  
25 mixed fuel issue, if you want to take a couple of

1 minutes.

2 MEMBER POWERS: A couple of minutes, I  
3 think, is totally acceptable.

4 MR. SEGALA: Okay.

5 MR. LU: Okay. My name is Shanlai Lu from  
6 the Rad Protection Branch, and lead reviewer on the  
7 EPR. I heard that there was questioning about a mixed  
8 core configuration, what are the limitations of the  
9 setpoint methodology, based on the SPND.

10 That's one of the limitations as a part of  
11 staff's approval. They have to use -- they can't have  
12 a mixed core, but each fuel bundle has to have  
13 identical set of correlation package. However,  
14 neutronically, if you're loading the uranium  
15 enrichment, maybe it could be different.

16 So I think that's the limitation we  
17 already imposed on that part of the SER. Did I answer  
18 your question about that?

19 MEMBER ABDEL-KHALIK: That's fine. We can  
20 pursue it in more detail later. Thank you.

21 MEMBER POWERS: Thank you. I think we're  
22 done.

23 CHAIR ARMIJO: Okay. Well, thank you,  
24 Dana. I think we're a little bit ahead of schedule.  
25 So we'll take a break and reconvene at 10:15.

1 (Whereupon, a short recess was taken.)

2 CHAIR ARMIJO: Okay. Let's come back to  
3 order. The next topic is the spent fuel pool scoping  
4 study, and the purpose of this meeting is to receive  
5 a briefing from the Office of Nuclear Regulatory  
6 Research on this study.

7 Our Subcommittee on Materials, Metallurgy  
8 and Reactor Fuels met with the staff on March 6th of  
9 this year in a closed forum, and at that meeting, some  
10 pre-decisional information was presented, as well as  
11 some official use only information.

12 That information will not be presented  
13 today or discussed. This will be an open session.  
14 We'll hear presentations from representatives of the  
15 Research staff, who will discuss the seismic and  
16 structural methods, the scenario delineation, accident  
17 progression and consequences analysis methods for the  
18 study.

19 Also, we've had a request from a member of  
20 the public, Mr. Bob Leyse, to give some remarks and  
21 comments for about five minutes, and I believe he also  
22 submitted a one-pager entitled "Spent Fuel Pools  
23 Bioresearch Overview: Phase 1 Testing," which all the  
24 Committee members have received.

25 With that, I'd like to turn it over to the

1 staff, whether it's Katie or Michael.

2 MR. SCOTT: Good morning, thank.

3 CHAIR ARMIJO: Okay, Michael.

4 MR. SCOTT: I'm Mike Scott. I'm the  
5 Deputy Division Director in the Division of Systems  
6 Analysis in the Office of Nuclear Regulatory Research,  
7 and I'd like to just make a few opening remarks.

8 The study that you'll be briefed on this  
9 morning to assess the potential safety benefits of  
10 expedited movement of spent fuel to casks was born  
11 from a steady interest in spent fuel consequences,  
12 expressed by members of the public and by Congress.

13 The Research staff was tasked with  
14 developing updated information on key aspects of  
15 potential spent fuel pool accident consequences on an  
16 aggressive one-year schedule. The staff was directed  
17 to move expeditiously, but also to conduct our work in  
18 a technically rigorous manner, using state of the art  
19 tools.

20 To accomplish this task, the staff has  
21 reviewed and is reviewing past consequence and risk  
22 assessments related to spent fuel storage, as well as  
23 other reports of relevance that have been developed by  
24 external stakeholders. The staff identified seismic  
25 hazard as a key piece of the overall spent fuel risk,



1 and you'll hear more about that from the team.

2 For that reason, seismic hazard was  
3 considered a logical place to start in probing the  
4 continued applicability of past studies, developing  
5 insights for the current spent fuel storage situation.  
6 Depending on the results gained from this study,  
7 additional work might be appropriate to obtain a more  
8 holistic answer on the path forward on this issue.

9 Along with providing general updates to  
10 past information, the study can provide a number of  
11 insights for scenarios investigated. For example,  
12 through accident progression time lines for spent fuel  
13 pools proceed more slowly than previously thought, as  
14 the agency has found to be the case for reactor events  
15 in the recent SOARCA analyses.

16 Do seismically-induced station blackout  
17 scenarios contribute significantly to overall  
18 consequences, or are the consequences dominated by  
19 seismically-induced pool drain-down? Do low density  
20 loading storage cases produce substantially different  
21 results in terms of public health effects and off-site  
22 consequences, compared to high density storage cases?

23 Do situations with successful mitigation  
24 substantially reduce the off-site consequences? We  
25 expect that insights such that we will obtain will

1 address issues such as these, and be very helpful in  
2 framing the ongoing discussions about whether  
3 expedited fuel movement produces any substantial  
4 safety benefits, and informing next steps.

5 Other ongoing efforts, such as plan site  
6 Level 3 PRA will complement and build on this work.  
7 Unless you have questions for me, I'll now turn it  
8 over to Katie Wagner to begin the presentation.

9 CHAIR ARMIJO: Mike, I have some comments,  
10 not necessarily questions. In the course of the  
11 presentation, I'd like to understand why this work is  
12 being done on an expedited basis, when we have  
13 demonstrated at the Fukushima event that the spent  
14 fuel pools performed their function, despite the  
15 severe seismic event, and despite hydrogen explosions  
16 and other problems?

17 So from a standpoint of priority of work  
18 by the staff, I'm struggling to understand what the  
19 reason or justification for this level of effort,  
20 other than -- and on this expedited schedule.

21 It seems that we're ignoring the facts of  
22 what actually happened in one of the most, in fact the  
23 most destructive event that happened in fuel pools of  
24 -- that we design and use in the United States.

25 So as the presentation goes forward, I'd

1 like to try and understand what is really driving this  
2 thing, because I just don't see a technical  
3 justification. That's a personal opinion that may or  
4 may not be shared by other members.

5 But it just seems odd to me that we're  
6 spending this kind of effort on this kind of study,  
7 and ignoring the facts of what happened at Fukushima.  
8 With that, I'll --

9 MR. SCOTT: I'd like to respond to that if  
10 I could. The emphasis on this task, which of course  
11 is only a relatively small part of the agency's  
12 resources that are being focused on lessons learned  
13 from Fukushima, the emphasis that has been provided on  
14 this task is focus both on the potentially significant  
15 consequences of this event, recognizing it's highly  
16 unlikely, and as I mentioned in my remarks, the high  
17 stakeholder interest in this subject that emerged from  
18 Fukushima.

19 So this is -- it is our, it's been our  
20 judgment that we need to address this issue as part of  
21 but not a major part of the efforts that are being  
22 focused on Fukushima and lessons learned from that.  
23 Okay?

24 CHAIR ARMIJO: Yeah. I think I understand  
25 the code words "high stakeholder interest," and I'll

1 leave it at that. But I was looking more for a  
2 technical justification. But let's move on. Katie,  
3 the floor is yours.

4 MS. WAGNER: All right. Good morning, and  
5 welcome to this briefing on the Office of Research's  
6 Spent Fuel Pool Scoping Study. I'd like to quickly  
7 introduce my colleagues.

8 We have Jose Pires, who's our structural  
9 analysis lead; Don Helton, who is our boundary  
10 conditions and probabilistic aspects lead. To the  
11 side is Andy Murphy, our seismic analysis lead;  
12 Hossein Esmaili, our accident progression lead; and  
13 A.J. Nosek, our off-site consequence lead.

14 Moving to Slide 2, the agency has a rich  
15 regulatory basis for its current position on spent  
16 fuel storage. A number of events, such as the change  
17 in path forward on long-term storage in the Fukushima  
18 accident, motivated the reassessment of the underlying  
19 knowledge base.

20 To launch this reassessment, an expedited  
21 limited scope consequence study was undertaken, to  
22 provide insights in one year. The objective of this  
23 study is to reexamine the impact of moving older spent  
24 fuel to dry cask storage in an expedited manner.

25 The results of this study will inform our

1 regulatory decision-making process, guided by  
2 a Tier 3 Japan Lessons Learned item entitled "Transfer  
3 of Spent Fuel to Dry Cask Storage."

4 Moving to Slide 3, you'll see on this time  
5 line that many activities have addressed spent fuel  
6 pool issues in the past, such as the resolution of  
7 Generic Issue 82 in the late 1980's, action plan  
8 activities to increase spent fuel pool cooling rates  
9 reliability in the mid-90's, the NUREG-1738, study for  
10 decommissioning in 2001, the post-9/11 security  
11 assessments, and comprehensive site-level 3 PRA, which  
12 is just starting.

13 Please note that on this slide, the two past  
14 studies, which include a probabilistic risk  
15 assessment, resolution of Generic Issue 82 and NUREG-  
16 1738 are surrounded by a box. Moving to Slide 3.

17 MEMBER SKILLMAN: Katie, what is the context  
18 of that comment, "surrounded by the box"? What are  
19 you communicating there please?

20 MS. WAGNER: It's just simply that there's  
21 no significance. It's just we wanted to point out  
22 which studies did and did not have a probabilistic  
23 risk assessment as part of the study.

24 MEMBER SKILLMAN: Thank you, thank you.

25 (Off record comment.)

1 MS. WAGNER: Obviously, spent fuel pool risk  
2 involves many components, several of which include  
3 spent fuel pool seismic hazards, cask drop hazards for  
4 spent fuel pools and emergency preparedness  
5 considerations on other topics. Past studies have  
6 indicated that spent fuel pool seismic hazard is an  
7 important piece of overall spent fuel pool risk, or  
8 overall spent fuel risk.

9 For this reason, spent fuel pool seismic  
10 hazard is the logical place to start probing the  
11 continued applicability of past studies in developing  
12 insights for the current spent fuel storage situation.  
13 Depending on the results gained from the study,  
14 additional work might be necessary to obtain a more  
15 holistic answer.

16 Moving to Slide 5, as you'll see on this  
17 slide, past studies show that seismic hazard is the  
18 most prominent contributor to spent fuel pool fuel  
19 uncover, as shown by these plots, showing the  
20 frequency of fuel uncover. I'd like to point out  
21 that in NUREG-1738, few hazards were used, and we  
22 chose to use the Livermore hazard curves, because they  
23 more closely match the updated USGS curves for the  
24 plant that we are studying, which is Peach Bottom.

25 Moving on to Slide 6, now I'd like to give

1 a brief overview of the spent fuel pool scoping study.  
2 The focus of the study is to reexamine the potential  
3 impacts on spent fuel pool safety in the event of a  
4 challenging beyond design basis seismic event.

5 For this study, emphasis has been put on  
6 obtaining timely results, by using available  
7 information and methods, a representative operating  
8 cycle for a BWR Mark I plant, which is Peach Bottom in  
9 this case, and past studies to narrow the study scope.

10 The time line of the study, which Mike Scott  
11 already pointed out, is very aggressive. The study  
12 plan was finalized in July 2011, and the Office of  
13 Research will be sending study results to NRR in June  
14 2012.

15 The closely-related Japan Lessons Learned  
16 Tier 3 item from SECY 12-0025, Transfer of Spent Fuel  
17 to Dry Cask Storage, addresses the bigger picture,  
18 with the spent fuel pool scoping study being a key  
19 component.

20 MEMBER STETKAR: Katie, before you switch to  
21 the next one, I mean for the benefit of the full  
22 Committee explain why you in particular selected  
23 boiling power reactor rather than a pressurized water  
24 reactor, because the main genesis of this question is  
25 the different configurations of the spent fuel pools,

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1 different connections to the spent fuel pools and  
2 boilers, versus pressurized water reactors and perhaps  
3 different vulnerabilities to seismic failures for the  
4 two fuel pools?

5 MS. WAGNER: Certainly. I'm going to ask  
6 Don to take that one.

7 MR. HELTON: Yes. I guess the first comment  
8 I'll make is, and something that we plan on making  
9 clear in the report, and it came up in the  
10 Subcommittee discussion, is we did not pick a boiling  
11 water reactor because we viewed them to be inherently  
12 more vulnerable. That was not part of the decision-  
13 making process.

14 There were a number of considerations that  
15 did, that were part of the decision-making process,  
16 including the level of stakeholder interest, the  
17 availability of MELCOR and MACCS-2 models, as well as  
18 finite element structural analysis models, the  
19 availability of information on the plant that we chose  
20 from some past studies.

21 Of course, the Peach Bottom plant is a BWR  
22 Mark I. Of course, the Fukushima had BWR Mark I's on  
23 the site. I won't say that that was -- I mean that  
24 was not a key part of the decision, but that it was  
25 another aspect of it.



1           So in the end, it was a combination of these  
2           different considerations that prompted us to choose  
3           this site.

4           MEMBER STETKAR: But generic conclusions  
5           across the entire operating fleet are going to be  
6           drawn as a result of this scoping study. Is there  
7           some chance -- you mentioned you didn't select the  
8           boiler, because you thought it might be more  
9           vulnerable? Is there some chance that it might be  
10          less vulnerable?

11          MR. HELTON: There is certainly that  
12          possibility. Our intent was not to do one, a site-  
13          specific analysis that could then be extrapolated to  
14          the industry, in terms of the fleet, without a  
15          tremendous amount of caution in doing so.

16          Our goal was to do a site-specific analysis  
17          of a plant that is fairly typical of the 20 or so Mark  
18          I BWRs in the U.S., and to go from there.

19          MEMBER STETKAR: Okay. That means the  
20          results have to be cast pretty carefully, because this  
21          -- so that it's not necessarily misinterpreted, that  
22          the results of the scoping study are indeed  
23          generically applicable to the entire fleet, in terms  
24          of policy decisions and, you know, what one should do  
25          going forward.

1                   MEMBER POWERS: Don, is Peach Bottom  
2                   representative? What I'm thinking is Peach Bottom  
3                   among BWRs is the plant that has been analyzed most  
4                   within the regulatory context, PRA and accident  
5                   analysis.

6                   Everybody does Peach Bottom, and  
7                   consequently, any flaws or oversights or deficiencies  
8                   have presumably been corrected at Peach Bottom,  
9                   whereas others have not been subjected to that kind of  
10                  scrutiny. So is Peach Bottom representative?

11                 MR. HELTON: I guess what I meant by that  
12                 was from a high level, from a design perspective, the  
13                 Mark I's have a fairly typical design. Even that  
14                 said, there are important differences from AE to AE  
15                 that can affect things like the structural assessment.

16                 We're not trying to make the case at this  
17                 point that from an as-operated perspective, that  
18                 globally it is or is not typical. Rather, we will try  
19                 as much as possible to say, to point out cases along  
20                 the way in our analysis, where we believe that  
21                 particular aspects are typical or atypical.

22                 An example of that is the way that Peach  
23                 Bottom chooses to do its fuel loading in the spent  
24                 fuel pool. They've actually gone beyond what is  
25                 required in regulatory space, in terms of the

1 arrangement of their fuel, to have an arrangement that  
2 is even more coolable, to use that terminology, than  
3 what is required.

4 That is something that we view as good, but  
5 atypical. So therefore in our study, we're looking at  
6 what the regulatory requirement is. So again, I don't  
7 want to make global statements about typical versus  
8 atypical, but in cases where, or in specific instances  
9 where we know it to be very typical, we'll try to  
10 identify those at that level.

11 MEMBER POWERS: If I were to ask you about  
12 PWR containments and their variability, you would  
13 point to a NUREG report that went through,  
14 deliberately comparing and contrasted all the  
15 structural features of PWR containments.

16 If I asked you for a similar thing about the  
17 structures of spent fuel pools in Mark I BWRs, is  
18 there a NUREG that you would point me to, that would  
19 say here, all 23 of them have been looked at and  
20 here's the information.

21 MR. HELTON: I'll defer that to Jose.

22 DR. PIRES: I have not seen a report that we  
23 did the level of detailed information that is for the  
24 containments, the reports that have containment  
25 information. There are some previous studies that

1 have looked at the spent fuel pools. There are some  
2 databases collected.

3 But I have not seen a report myself with the  
4 level of detail that are in the reports that have  
5 containment databases. We are trying to start one,  
6 but it's a slow process.

7 MEMBER POWERS: Yeah. I think that would be  
8 a -- I mean it strikes me how often I refer to that  
9 report that the staff prepared on the structural  
10 details of all the containments. I mean my copy has  
11 lost its binding and most of its cover, I pull it out  
12 so often.

13 A similar thing, given the interest in spent  
14 fuel pool, it might be something to consider, maybe  
15 not as part of this study, but as some follow-on  
16 activity, because you know, these questions come up,  
17 and like I say, I pull my containment thing down every  
18 time a containment question comes up.

19 DR. PIRES: Yes. We have a contract with  
20 Sandia Labs to develop some --

21 (Simultaneous speaking; laughter.)

22 DR. PIRES: As a varied utility that has a  
23 lot of information on containments, and we have been  
24 debating whether to expand it, to include information  
25 on spent fuel pools in that project. I know that for

1 some security studies, there has been information  
2 collected on numerous spent fuel pools, but the budget  
3 for that --

4 CHAIR ARMIJO: That's accessible to you, but  
5 not to the general public.

6 MS. WAGNER: Let's move to Slide 7. For the  
7 technical approach of the study, we will be  
8 specifically considering two conditions. One is  
9 representative of the current situation for the  
10 selected site, with a high density loading and a  
11 relatively high density loading configuration, and a  
12 relatively full spent fuel pool.

13 The other is representative of a situation  
14 in which ex-bed movement of the older fuel to a dry  
15 cask storage facility has taken place, with a low  
16 density loading situation. The elements of the study  
17 include a seismic and structural assessment, a scale  
18 analysis of reactor-building dose rates, a MELCOR  
19 accident progression analysis, and emergency planning  
20 assessment, a MAX-2 off-site consequence analysis and  
21 probabilistic considerations.

22 MEMBER REMPE: What version of MELCOR is it  
23 you're using? Is it 2.1 or is it another version?

24 MR. HELTON: We're using 1.86 right now for  
25 the scoping study. We've also been playing around

1 with doing the same calculations in 2.1. But there's  
2 some unique aspects of MELCOR that were added to the  
3 1.85 version and carried forward to 1.86 for a spent  
4 fuel pool analysis.

5 So like I said, at this point, we're doing  
6 it in 1.86, and then also exploring the feasibility of  
7 basically doing the same thing in 2.1.

8 MEMBER REMPE: So some of the models in 1.86  
9 are not in 2.1?

10 MR. HELTON: I think from a reactor  
11 standpoint, the answer is everything that's in 1.86 is  
12 in 2.1. There are potentially some unique features  
13 for spent fuel pool analysis.

14 MEMBER REMPE: That were not carried  
15 forward?

16 MR. HELTON: That were not carried forward,  
17 and if I've misspoken, then the MELCOR guru back there  
18 will correct me.

19 MR. ESMAILI: All the models that are in  
20 1.86 are now -- Hossein Esmaili. All the models that  
21 are in 1.86 are in 2.1. So we just made the choice,  
22 because we had the model available in 1.86, and we  
23 didn't want to convert it to 2.1 because it would take  
24 a long time. So this is what will work.

25 (Off record comments.)

1 MS. WAGNER: Thank you. If those are all  
2 the questions on that slide, then now I'll turn things  
3 over to Jose Pires, who will discuss seismic and  
4 structural methods used in the study.

5 CHAIR ARMIJO: Katie, just before you do  
6 that, this study takes you the point where you've  
7 damaged, you've drained the pool at some extreme, you  
8 know, for some extreme conditions. You get to a  
9 situation where you're draining the pool and you've  
10 had a zirconium oxidation and hydrogen release.

11 In this study, will you just let that  
12 released radioactivity be dispersed in a normal way,  
13 or would you, will you also incorporate at some point  
14 a hydrogen explosion resulting from the cladding?

15 MS. WAGNER: I'm going to turn that to Don,  
16 since he's presenting on that.

17 MR. HELTON: Yeah. Let me give you a quick  
18 answer, just to answer that, because I think when we  
19 go through we'll answer some of this. What Jose is  
20 going to talk about is the fact that we don't presume  
21 failure of the pool.

22 We study the pool from a finite element  
23 analysis, impose this event on it, and then predict  
24 what's actually going to happen.

25 CHAIR ARMIJO: I appreciate that, Don. But

1 as you crank up the seismic, the magnitude, you'll get  
2 to a point where you can fail just about anything.

3 MR. HELTON: Of course.

4 CHAIR ARMIJO: Yes, and so if you take it to  
5 that point and you fail the structure or the liners  
6 and you drain the pool, and you get a zirconium  
7 oxidation in the hydrogen release, do you then  
8 incorporate the hydrogen explosion into your analysis?

9 MR. HELTON: The answer is if we produce  
10 sufficient hydrogen, and this depends on when the  
11 oxidation is occurring and to what extent it's  
12 happening in an arid environment, which will not  
13 produce hydrogen, versus a steam environment, which  
14 will.

15 But if we produce enough hydrogen and it  
16 transports, and the conditions are such that a  
17 hydrogen deflagration would be predicted, then yes,  
18 we'll model that.

19 CHAIR ARMIJO: Thank you.

20 MEMBER POWERS: But he asked you about an  
21 explosion.

22 CHAIR ARMIJO: Well, yeah. I was saying the  
23 worst case, a real explosion. If it can't happen,  
24 that's good to know. If it does happen, can happen --

25 MEMBER POWERS: It could happen and not



1       calculated to happen are two different things.

2               MR. HELTON: We would expect it if  
3       sufficient hydrogen was generated to have a  
4       deflagration or detonation event, that would at a  
5       minimum blow out panels on the refueling floor, and  
6       potentially cause additional damage, and we will, to  
7       the best of our abilities, model that.

8               CHAIR ARMIJO: Okay.

9               MEMBER POWERS: Can you model the DDT?

10              MR. HELTON: I'm sorry?

11              MEMBER POWERS: Can you model a deflagration  
12       to detonation transition?

13              MR. HELTON: We will use the resident models  
14       in MELCOR to predict the combustion of hydrogen.

15              MEMBER POWERS: You're deliberately not  
16       answering my question.

17              MR. HELTON: I'll deliberately defer your  
18       question to Jose.

19              (Laughter.)

20              DR. PIRES: No, we do not, Dr. Powers. We  
21       just, if there is the conditions for detonation, we  
22       just flag it, that there are conditions for  
23       detonation. But we do not model DDT. We only model  
24       a hydrogen burn.

25              MR. HELTON: But just to be clear, that

1 hydrogen burn has the capability and will produce  
2 pressure differentials that will again, at a minimum,  
3 fail blowout panels on the refuel floor.

4 DR. PIRES: Yeah, and for this particular  
5 case, you know, if there are no igniters, the MELCOR  
6 default for the onset of hydrogen combustion is about  
7 ten percent hydrogen, that you can really achieve very  
8 quickly.

9 MEMBER POWERS: But how do you flag when  
10 you're ripe for DDT?

11 MR. HELTON: I'm sorry. I'm not trying to  
12 be difficult. I've lost hearing on my right ear, so  
13 --

14 MEMBER POWERS: I've been accused of  
15 speaking too softly.

16 MEMBER CORRADINI: Accused or guilty?

17 (Laughter.)

18 MEMBER POWERS: Accused.

19 (Simultaneous speaking.)

20 MR. HELTON: He's got my good ear.

21 (Laughter.)

22 MEMBER POWERS: Now the question is, and I'm  
23 bringing it up because there's been a lot of work  
24 lately on the issue of deflagration to detonation  
25 transitions, and it becomes very pertinent in thinking

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1 about the Fukushima accident, and the statement was  
2 that they flag when they're ripe for DDT, and I just  
3 wondered how they did that.

4 DR. PIRES: Again, in MELCOR, we don't have  
5 such a model.

6 MEMBER POWERS: Oh, I misunderstood.

7 DR. PIRES: And you know, the refueling bay  
8 is an open environment. So the conditions for a DDT,  
9 it could happen, but you know how you get into a very  
10 open environment, it's probably going to burn, as  
11 opposed to going through the --

12 MEMBER POWERS: An open environment like a  
13 reactor building?

14 DR. PIRES: Yeah, in top of the refueling  
15 floor.

16 MEMBER CORRADINI: So can I ask Dana's  
17 question a bit differently? The last time I remember  
18 this being looked at in great detail was essentially  
19 for ice condensers, because of the run-up of the  
20 channel surrounding the baskets. I guess to reverse  
21 the question, is there any characteristics in some of  
22 the geometries that essentially look like where the  
23 NRC's research, from many years ago, were concerned  
24 about that, because it's a geometrical effect?

25 DR. PIRES: Yes. And again, I haven't

1 looked. Again, since we don't have the model in  
2 MELCOR --

3 MEMBER CORRADINI: Okay.

4 CHAIR ARMIJO: Jose.

5 DR. PIRES: I will talk about the peak  
6 ground seismic scenario and the structural analysis  
7 that we are -- the approaches that we are utilizing.  
8 The seismic scenario for this event is a challenging  
9 event, but with a very low frequency of occurrence  
10 that has been estimated to be 1 in 60,000, 61,000  
11 years.

12 The PGA for, peak ground acceleration for  
13 this event, if you would characterize the earthquake  
14 in those times, is in the range from .5 to 1G, and  
15 specifically we have been looking at an earthquake  
16 with an acceleration of .71G peak ground acceleration.

17 If you see how that compares to the safe  
18 shutdown earthquake and the operating basis  
19 earthquake, it is about six times greater. So it's a  
20 very challenging event. Why did we pick this event,  
21 and that was because of some review of past studies  
22 indicates that you would have to go to events in this  
23 range to start challenging the spent fuel pool  
24 structure.

25 So if you move to the next slide, the other

1 --

2 MEMBER CORRADINI: Can I ask a question that  
3 we've been debating from your Subcommittee meeting,  
4 and we'll do it out in the open a bit? So you're  
5 picking a -- you don't have to go back -- but in the  
6 previous slide, a range of what I'll call single large  
7 seismic events.

8 From the standpoint of seismic analysis, is  
9 one big one worse than a bunch of little ones that add  
10 up to the same energy?

11 DR. PIRES: No, I don't think so, not for  
12 this structure.

13 MEMBER CORRADINI: So then if I -- you see  
14 where I'm going with this? So then if one did a  
15 series of smaller seismic events, could I end up with  
16 more accumulated damage? That's where I'm going with  
17 it.

18 DR. PIRES: Right. No, I don't think so for  
19 this structure. My understanding of the behavior of  
20 the spent fuel pool structure is that this tends to be  
21 relatively brittle, and so it is more of a threshold-  
22 type event. If you have many, many loading cycles  
23 before certain level, you have almost no damage. Then  
24 you start exceeding certain levels, you start seeing  
25 damage.

1           So it's pretty much the intensity of the  
2 motion with a certain duration that controls.

3           MEMBER REMPE: So even a big one followed by  
4 some smaller ones would not cause some aftershocks,  
5 would not cause --

6           DR. PIRES: I also --

7           CHAIR ARMIJO: If you really damage -- if  
8 it's big enough to start cracks, and you have  
9 subsequent ones, it's not going to help. That's what  
10 happened in Fukushima. They had 7, greater than  
11 magnitude 7 after the initial big one, and then a  
12 bunch at greater than 5, and hundreds after that,  
13 smaller ones. So nature has a way of making it worse.

14           MEMBER CORRADINI: The reason that we were  
15 asking the question on this site is it's the -- the  
16 way you answered, I want to make sure I get clear.  
17 The way you answered it is the initial big one,  
18 because of the brittle behavior thing, really does the  
19 damage, and all the accumulated other ones, if I never  
20 had the big one, would never be noticed?

21           DR. PIRES: Exactly, the one previous to  
22 that, yeah. And I will repeat, it's not completely  
23 brittle damage, but it's on the brittle side. Not  
24 totally brittle, in terms of at least of the cracking.

25           CHAIR ARMIJO: I just get -- I'm not a

1 seismic guy, but I'm just curious, .71. Why not .70  
2 or .75, some bigger point, you know?

3 DR. PIRES: It's sometimes on estimating the  
4 central point of an interpolate (ph). You either use  
5 the arithmetic mean or the geometric, and the  
6 geometric mean was used here, so that it was just --  
7 because some of these things tend to be linear on  
8 logarithmic scales, and so what's convenient.

9 CHAIR ARMIJO: Okay. I just thought there  
10 was something magical about that number.

11 MR. HELTON: It's the square root of 1 times  
12 .5.

13 CHAIR ARMIJO: That's a lot.

14 MEMBER SCHULTZ: But the way it's presented  
15 here, and I'll just make this comment now; I may come  
16 back to it later. The way it's presented here, given  
17 that this is going to be a high profile, well-read  
18 document, is that we are dealing with accurate  
19 numbers.

20 MEMBER CORRADINI: Right.

21 MEMBER SCHULTZ: And it will be perceived,  
22 then, that the agency has developed a very accurate  
23 analysis, therefore, of what could happen. So  
24 presenting .71 or 1 in 61,000 years for the event  
25 suggests that we really know about this event, and

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1 we're really going to tell and evaluate what will  
2 happen, not what can happen or might happen, but what  
3 will happen. We need to be very cautious about that  
4 and present --

5 CHAIR ARMIJO: On what's presented, yes.

6 DR. PIRES: That's a good point.

7 MEMBER SCHULTZ: That's where using  
8 something like .7 or 10 to the minus 5th or 10 to the  
9 minus 6th, picking one makes more sense.

10 MEMBER CORRADINI: Yeah, because really  
11 you're -- I mean the easy way of saying it is that  
12 your uncertainty might be an order of magnitude. So  
13 showing anything less than -- showing anything with  
14 more precision than order of magnitude conveys almost  
15 too much certainty.

16 MEMBER STETKAR: Or doing an actual  
17 uncertainty analysis.

18 MEMBER CORRADINI: Or doing an actual  
19 uncertainty analysis that goes along with that.

20 MEMBER STETKAR: That has uncertainty in  
21 both the seismic hazard and the seismic fragilities.

22 DR. PIRES: Yeah, I agree with that. It's  
23 more accuracy --. The seismic, in addition to the  
24 peak ground acceleration, it is also important to  
25 characterize the vibration of the ground to response

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1 spectra. What is the frequency content in the  
2 vibrations of the ground?

3 So what -- we also use the USGS 2008 seismic  
4 hazard models for that, and these were similar to the  
5 models that were used for the Generic Issue 199.

6 So based on that, we obtained what's called  
7 the ground motion response spectra for that site, and  
8 then that was scaled up to the intensity that we are  
9 considering, that is actually greater than what the  
10 ground motion -- that for the ground motion response  
11 spectra.

12 One comment here is that compared to two  
13 points, the design earthquake and earthquakes used in  
14 PRAs for this plant, and earthquakes used in previous  
15 studies for spent fuel pools, these earthquakes is  
16 rich in the I frequency, and it's a rock site too  
17 here, and natural frequencies of the spent fuel pool  
18 structure are also in that range, up to 20 hertz.  
19 That was different from previous studies. If you go  
20 to the next slide --

21 MEMBER SKILLMAN: So -- go ahead. Go to  
22 your next slide.

23 DR. PIRES: So this shows just that we  
24 compared the ground motion response spectra for this  
25 site and for this study, which is the red line in that

1 picture. We did the purple line, which is the design  
2 basis earthquake, the safe shutdown earthquake.

3 You can see it's much far in excess of the  
4 design basis earthquake, and you can see that there is  
5 some energy carried on the I frequencies of the  
6 ground, of the motion.

7 MEMBER CORRADINI: So, and this was simply  
8 -- I mean maybe I missed it in the Subcommittee  
9 meeting. This is simply a multiplicative factor of a  
10 smaller curve? It seems a bit more stylized than  
11 that, and I don't remember why it's more stylized, I  
12 guess.

13 DR. PIRES: The ground motion response  
14 spectra for the site is about half of the red line  
15 there, but the shape is the same. So that was scaled  
16 up for the intensity that we used for the study.

17 MEMBER CORRADINI: Right, on the low  
18 frequency side. But on the high frequency side, it's  
19 --

20 DR. PIRES: The shape is the same. The  
21 shape of the earthquake, based on the more recent  
22 seismic hazard models, is the one given by the red  
23 line which, as you can see, shifts the energy to the  
24 I frequencies.

25 MEMBER CORRADINI: Okay, I'm sorry.

1 CHAIR ARMIJO: Yes. That's a new model.

2 DR. PIRES: The new model.

3 CHAIR ARMIJO: Okay.

4 MEMBER CORRADINI: Right. The new model,  
5 though, with six -- where you've essentially amplified  
6 it by just a constant?

7 DR. PIRES: Yes.

8 MEMBER CORRADINI: Okay. That's what I  
9 missed. All right, sorry. Thank you.

10 DR. PIRES: Sure.

11 MEMBER RAY: Well but okay. Then I have to  
12 ask this question. We start off the proposition that  
13 it's six times the PGA and six times the SSE for  
14 existing plants. Of course, new plants typically are  
15 .3.

16 DR. PIRES: Right.

17 MEMBER RAY: So you wouldn't want the  
18 inference to be that that's the way plants would be  
19 licensed today, six times that. It's six times for  
20 the existing plant, or I guess for Peach Bottom, or  
21 the 25 plants you referred to.

22 It just bothered me a little bit that the  
23 inference would be that it's six times what a plant in  
24 the central and eastern U.S. would be designed to  
25 today. It's a similar comment to the one Steve made,

1 I think. It's what is the perception of what you're  
2 saying that is being conveyed.

3 DR. PIRES: I was just referring to the  
4 particular site here. If you will consider the ground  
5 motion response spectra, that will be similar to what  
6 the plant would be designed for today. That is only  
7 about a factor of two.

8 MEMBER RAY: That's right.

9 DR. PIRES: Two, a little bit over two.  
10 From .3 to .7.

11 MEMBER RAY: Yeah, and I think that that  
12 message is -- I mean I understand what you're saying  
13 is accurate. It's just what do people hear that I'm  
14 commenting about.

15 CHAIR ARMIJO: Okay.

16 DR. PIRES: For the spectral analysis, or  
17 the objective of the spectral analysis is to determine  
18 what the initial conditions for the remaining part of  
19 the study, the accident progression analysis.

20 What we looked for primarily here was I  
21 start with the bullet right at the bottom, was for  
22 what would be the distortions and the displacement  
23 strengths in structure of the pool and the liner.

24 And so that was the primary results that we  
25 are trying to obtain. We are going to -- we follow an

1 approach that was used in a previous study, that  
2 looked at the fragilities of spent fuel pool  
3 structures, that was done for the resolution of the  
4 Generic Issue 82.

5 So we followed the general approach. We  
6 modified it somewhat to do more detailed analysis of  
7 the structure of the pool itself. They did some end  
8 calculations.

9 Here, we did finite element modeling. So a  
10 little bit more detail there, because the structure of  
11 the pool is complex and we were trying -- you know,  
12 part of the purpose here is to look at cracking  
13 patterns.

14 We have been leveraging data that existed  
15 for the NUREG-1150 PRA, the flaw response spectra data  
16 was calculated there, that is accelerations at various  
17 points on the structure. So we can leverage that  
18 data, and scale it as an input for this study. That  
19 was an advantage. Like Don pointed earlier, this  
20 information was part of the reasons why we chose this  
21 plan.

22 So if you move to the next slide. These are  
23 just some pictures to illustrate the configuration of  
24 the building. The reactor building is down there on  
25 the upper left corner. We ended up not modeling the

1 entire building. We just isolated -- we used loads  
2 already calculated in previous studies, and then  
3 isolated the structure of the pool itself.

4 You can see that on the right, which shows  
5 the spent fuel pool and also the dryer-separated pool.  
6 You can model the other part. Spent fuel pool  
7 structurally supported on the reactor shield building  
8 on one side, and then on the other side it's supported  
9 on the exterior wall.

10 It's a reinforced concrete structure. It's  
11 very thick walls, very strong walls. It also has  
12 embedded beams and girders on the floor, which provide  
13 additional strengths to the structure.

14 MEMBER SKILLMAN: Jose, in the upper left  
15 image, there are colors from the base mat to the steel  
16 bracing. What do the colors represent please?

17 DR. PIRES: They don't represent anything of  
18 significance. It's that we were -- at some point we  
19 thought it would be useful to do an entire finite  
20 element model of the structure, and actually generate  
21 our response spectra.

22 But we realized we would not have  
23 possibility of doing that in the scope of time that we  
24 have, and that is just we were dividing the models in  
25 parts for your convenience.

1           So there is nothing special. You can see at  
2           the top the spent fuel pool floor, and that area above  
3           the spent fuel pool floor tends to be metallic in some  
4           of these reactors.

5           It tends to be a metallic frame. It carries  
6           the crane. It's a very heavy crane, rated for over  
7           120 tons, and it's an open area. That's an entire  
8           open area there. So that's, I guess, the open space  
9           that was referred to before.

10           MEMBER SKILLMAN: Thank you.

11           DR. PIRES: And then shield panels in  
12           between those empty spaces there, that are, tend to be  
13           metallic panels.

14           MEMBER ABDEL-KHALIK: The analysis was done  
15           with the gates up?

16           DR. PIRES: Yes.

17           MEMBER ABDEL-KHALIK: Does it make any  
18           difference if you're in a refueling configuration?

19           DR. PIRES: Not a significant difference  
20           within the approximations that we are considering.

21           MEMBER ABDEL-KHALIK: How about sloshing?

22           DR. PIRES: The sloshing tends to be longer  
23           period, long period, and affected by the long period  
24           components on the ground motion. And it might make  
25           some difference, but the sloshing, we would not expect

1 it to be an important component on the loss of water  
2 from the --

3 MEMBER ABDEL-KHALIK: And this is just  
4 intuitive?

5 DR. PIRES: It's not completely intuitive.  
6 We did some preliminary calculations, simply by  
7 calculation by hand, just to see what the results,  
8 range of the results would be, and that came up with  
9 numbers for sloshing that are relatively small.

10 MEMBER ABDEL-KHALIK: But aside from  
11 sloshing, the presence of the gates, does it make any  
12 difference?

13 DR. PIRES: In my opinion, it does not make  
14 a difference, on the loads calculated and on the  
15 damage to the pool. It's my opinion. The other place  
16 where it could make some difference, for instance,  
17 would be there is an autodynamic load that is the  
18 impulsive load of the water.

19 But on -- these are almost 40 feet deep or  
20 40 feet wide. So that mass of water there is going to  
21 be moving with the pool during the earthquake, and the  
22 small dimensions of that gate will not have a  
23 significant effect on that, in my opinion. But we  
24 didn't verify it with analysis.

25 MEMBER ABDEL-KHALIK: My concern would be



1 the coupling between both sides of the pool.

2 DR. PIRES: Yeah. I don't expect that it  
3 will be a measure. Can you go to the next slide?

4 I should make a comment before moving to the  
5 next slide, that was a question that was brought up  
6 before, is ordinarily, you'd use the pool, and there  
7 will be differences between the pool, depending upon  
8 the architect engineer, not only on the amount of  
9 reinforcement and other details on the floors.

10 Also, there will be differences, for  
11 example, on how the liner is attached. So some  
12 architects and engineers would have different choices  
13 on those details. However, they would all be trying  
14 to achieve the same goals, just with different  
15 details, I presume.

16 After I said we have looked at where, and we  
17 used simpler approaches for that, was penetrations.  
18 The displacements would be very small. These are very  
19 stiff structures, very thick. So the displacements  
20 would be small and likely the penetrations will be  
21 damaged.

22 We looked at AC and DC power fragilities,  
23 and took a look also at fragilities estimated for  
24 other buildings, like the building that would house  
25 the B5B equipment. That's not a seismic integrity

1 warrants action.

2 MEMBER POWERS: I'm intrigued by the  
3 statement that the systems are very stiff, and it's  
4 unlikely that the penetrations would be damaged.

5 I'm familiar with a variety of tests of  
6 containment structures, which I presume are stiff, and  
7 I cannot think of a single case in which the  
8 penetration regions survived an overpressurization,  
9 which is quite different than what you're talking  
10 about here.

11 But in every case, I think the damage to the  
12 structure was most noticeable around penetrations. So  
13 I ask you what do you have as far as experimental  
14 validation of this argument that the penetrations are  
15 going to be invulnerable to damage in these stiff  
16 structures?

17 DR. PIRES: Yeah. The containment  
18 structures are different. It's the entire wall of the  
19 containment is pretty much under the same uniform  
20 strength. The strength is very uniform over the  
21 entire wall, because of the internal pressurization.

22 Then there are strength concentrations  
23 around the penetrations, and because of that, either  
24 the containment structure around the penetration you  
25 start developing of tear points in the concrete

1       containment on the liner. The containment will not  
2       fail catastrophically, but the tear -- if you are  
3       going to develop tears, they would be in the regions  
4       of strength concentrations.

5               In this case, but still other penetrations,  
6       you know, there have been tests of barrels.  
7       Penetrations are designed to accommodate some of these  
8       deformations. They themselves have not failed in some  
9       of the tests that I have looked at, but it was the  
10      region of the containment where it transitioned to the  
11      penetration, where you have strength concentrations.

12             In this case here, the displacements that  
13      exist, and even those are small, tend to be near the  
14      bottom of the walls and they're very small, very, very  
15      small displacements. They concentrate near the bottom  
16      at the intersection of the walls and the pool. At  
17      that level, you don't have penetrations. Penetrations  
18      are further up, above the level of the racks.

19             So and there, the displacements are very,  
20      very small. So that's the basis for my argument, and  
21      we are looking at models to calculate strength  
22      concentrations in the outer area, in the liner,  
23      similar to what was done for containments.

24             Some approximations we made here is because  
25      this ground motion is high frequencies, and there is

1 incoherency on the vibrations of the ground, there are  
2 matters that have been used recently to take into  
3 account that incoherency, because that will reduce the  
4 loads that I've seen through the structure.

5 Those were -- here, we're just using  
6 approximations. Although this is probably not a  
7 structure where there will be much reduction from  
8 those incoherency facts, but we still accounted for  
9 them in approximation, in a manner that was probably  
10 somewhat conservative in this case.

11 So some coupling of the structure and the  
12 pool itself might also lead to some reductions in the  
13 load. Those were not accounted for here, and so those  
14 are some approximations that we made, that may be on  
15 the conservative side.

16 And what else? Oh, another thing is the  
17 load from the racks was using approximation. The  
18 assumption made here is what that for these floating  
19 racks that are allowed to slide, they tend to be --  
20 the movement of the racks tends to be longer periods.

21 So they are decoupled dynamically from the  
22 structure. So there are dynamic amplification of --  
23 the inertial loads on those would be calculated using  
24 a factor of one, so doubling essentially their dead  
25 weight. And that the spent fuel damaged state, we are

1 assuming that that damaged state to the envelope,  
2 potential leakage from the transfer gate or from the  
3 dryer pool for the conditions, some conditions on the  
4 operating cycle, in which the gates would be open.

5 And so what the end result that we are  
6 looking for is a few discrete damage states that will  
7 be minimal in terms of their relative likelihoods.

8 MEMBER SCHULTZ: So with regard to the first  
9 three items here, the impression is that you could  
10 have done more detailed or more complex analyses, and  
11 demonstrated what these assumptions, the effect these  
12 assumptions had on the results that have been  
13 produced?

14 DR. PIRES: It is happened. Yes, it is  
15 always possible to do that. In the case of the I  
16 frequency, for example, many of the reductions that I  
17 have been seeing have been claimed for structures with  
18 a very deep place mat, say 15 feet, in some places 20  
19 feet. Very few place mats are uniform over the  
20 foundation.

21 That's not the case in this structure. It's  
22 only, the foundation is only four feet thick, and it's  
23 not uniform. Near the drywell foundation, it is  
24 thicker, so it's not -- the dimensions.

25 So the drywell pretty much is the structure

1 that transmits the vertical motions to the pool, and  
2 that's only about 60 feet in diameter at the  
3 foundation, not at the size of the foundations in  
4 which you have seen large reductions from this  
5 incoherency effect. So this judgment made us conclude  
6 that that was probably not where we should put our  
7 effort at this time.

8 MEMBER SCHULTZ: What I'm trying to get to  
9 is were these not investigated in more detail because  
10 of lack of time? Would you have wanted to look at  
11 these in more detail, or did you assume we're really  
12 trying to develop -- we're really trying to develop a  
13 damage state for the spent fuel pool.

14 Therefore, we could identify these in more  
15 detail, but then if we didn't damage the spent fuel  
16 pool substantially enough, we would increase the  
17 magnitude of the seismic event, and so we would get  
18 there?

19 DR. PIRES: No, that was not the reason.  
20 The main reason was these arguments that I told you,  
21 that these -- that incoherency effect is normally  
22 observed for dimensions of 150 feet. This reactor  
23 building is 150 feet, but the foundation is not  
24 uniform in thickness, and it's thinner than the  
25 others.

1           So our judgment was that that reduction  
2           would most likely not be of significance, given other  
3           uncertainties for us to spend time doing that with  
4           these models.

5           MEMBER SCHULTZ: Good.

6           MEMBER STETKAR: Jose, and just to be clear,  
7           there's no effort in this study to develop any type of  
8           fragility-type curve for any of these structures or  
9           connections, was there?

10          DR. PIRES: The only effort is down at the  
11          bottom, to when we tried to calculate the likelihood  
12          of those damage states.

13          MEMBER STETKAR: But damage states given  
14          that specific acceleration?

15          DR. PIRES: Exactly.

16          MEMBER STETKAR: Not what I'm talking about  
17          is fragility curve, as a function of applied  
18          acceleration?

19          DR. PIRES: It's not the full fragility  
20          curve, but it's just we did some sensitivity or we are  
21          doing some sensitivity. But just for that purpose, to  
22          see what would be the uncertainty around that, so that  
23          you can estimate some standard deviations to calculate  
24          the relative likelihoods.

25          MEMBER STETKAR: Yeah. That's a different

1 concept there than what I'm discussing. Thanks.

2 DR. PIRES: And that's it. That is my last  
3 slide.

4 MR. HELTON: Okay. This is me. I'm Don  
5 Helton, and I'll be talking to you about the scenario  
6 delineation part of this, the MELCOR modeling and the  
7 MACCS-2 modeling.

8 The next slide here just tries to show you  
9 how we've discretized this problem in the time domain.  
10 So we're looking at a typical operating cycle of 23  
11 months, almost two years.

12 The first 25 days of that, just under a  
13 month, is the outage, and then followed by the post-  
14 outage period. Obviously, in terms of decay heat and  
15 movement of fuel, there's more going on or at least  
16 movement of recently discharged fuel, there's more  
17 going on during the first part of the operating cycle.  
18 So we've preferentially weighted that part of the  
19 cycle, in terms of discretizing the time domain.

20 So basically we've broken it up into five,  
21 what we would term as operating cycle phases, and the  
22 first two of those are during the outage, and then the  
23 remaining three cover the remainder of the operating  
24 cycle.

25 MEMBER SKILLMAN: Don, to what extent would



1 an emergency offload of the entire core at the end of  
2 OCP No. 3 do to your, if you will, to your results?

3 MR. HELTON: It would certainly affect --  
4 for the sort of instantaneous part, or for that little  
5 part of time while the emergency offload had taken  
6 place, then it certainly could affect the results.

7 We would expect it to affect the results for  
8 both the high density and the low density case, and  
9 other than that, the only other thing I'd offer is  
10 that, you know, this was a point of discussion at the  
11 Subcommittee.

12 So I did go, just anecdotally go and talk to  
13 some folks in our Office of Regulation, to try to get  
14 a feel myself for how typical that sort of occasion  
15 is, and at least anecdotally, the information was is  
16 that it would be highly atypical, but certainly  
17 possible.

18 MEMBER SKILLMAN: Thank you.

19 MR. HELTON: The next slide just tries to  
20 orient us a little bit with regard to the mitigation  
21 assumptions. So at this point, I just want to remind  
22 you that we are looking at a situation with high  
23 density loading, and then a separate situation with  
24 low density loading, where the fuel older than five  
25 years has been removed from the spent fuel pool.

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1           For the high density configuration, we're  
2           basically looking at two alternatives there. One is  
3           a situation where the licensee has re-arranged the  
4           fuel prior to the outage, such that the recently  
5           discharged fuel goes directly into a one by four  
6           pattern, and that is consistent with what the plant  
7           that we're studying, Peach Bottom, does, but  
8           recognizing that that's not necessarily the case for  
9           all licensees.

10           We also have another alternative where  
11           during the outage, the fuel is stored contiguously,  
12           and then placed into a one by four configuration after  
13           the outage. So we're going to talk about -- we're  
14           going to use this terminology, and we recognize it's  
15           not perfect.

16           We're going to use the terminology  
17           "unmitigated" and "mitigated," and we've wrestled with  
18           other terminology like optimistic and pessimistic and  
19           other things, and certainly welcome any thoughts you  
20           guys have on that front.

21           But for the moment, we're going to use this  
22           unmitigated and mitigated terminology. For the  
23           unmitigated scenarios, what that means is that no  
24           operator action is taken for 72 hours, and 72 hours  
25           right now is the time that we're using to truncate the

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1 calculations and the pool has either reached a stable  
2 steady state, or has not gone to release by that  
3 point.

4 So for unmitigated cases, no operator  
5 action, and I'll touch upon this again in a minute.  
6 But what that means is we are also not considering  
7 repair and recovery of the spent fuel pool cooling and  
8 other systems, and basically what this comes down to  
9 is non-recovery of AC power, because that's clearly  
10 what's prohibiting the use of the equipment that's  
11 used for dealing with the spent fuel pool.

12 MEMBER CORRADINI: So I'm sure you said this  
13 in the Subcommittee, but I guess I forget. So that's  
14 going to be viewed as a high density, no mitigation of  
15 bounding calculation, to show what?

16 MR. HELTON: Let me -- do you need to do a  
17 calculation? I think I could surmise where we're  
18 going with that one.

19 MEMBER CORRADINI: No. I think you  
20 definitely need to do that calculation. I'm also  
21 going to object a little bit to the use of the term  
22 "bounding," because as you guys would point out, we  
23 could have chosen other things like an emergency  
24 offload.

25 MEMBER CORRADINI: That's fair. We could

1 have done that. But still it is a pessimistic case.

2 MR. HELTON: Okay. But it's not the same as  
3 saying that all hope is lost, in the sense that we  
4 will have any number of conditions that by 72 hours  
5 will not have had a release. If you don't -- for  
6 instance, if you're in a pure boil-off situation and  
7 let's say you're --

8 MEMBER CORRADINI: Okay, that's fine, that's  
9 fine. I'm with you.

10 MR. HELTON: Does that make sense?

11 MEMBER CORRADINI: Yes. I just -- and then  
12 the, and again maybe I asked this in the Subcommittee  
13 meeting. I don't remember. Is this a matter of just  
14 time to the end of the study, that you didn't do some  
15 sensitivities, in terms of operator actions at a day,  
16 three days, some time, to see if that a big effect on  
17 it?

18 MR. HELTON: I wouldn't really say that it  
19 was a function of the study being expedited, so much  
20 as we -- it was decided at the beginning that we were  
21 not going to do an HRA.

22 MEMBER CORRADINI: That's fine. That helps  
23 me.

24 MR. HELTON: So that sort of sets you down  
25 --

1 MEMBER CORRADINI: So it's essentially kind  
2 of two --

3 MR. HELTON: Right, not extremes, but two  
4 situations, an optimistic and a pessimistic.

5 (Simultaneous speaking.)

6 MR. HELTON: Okay. For the mitigated  
7 scenarios, what that means is first of all, we're  
8 assuming diagnosis of the need to take mitigation  
9 based on a loss of level and time for observation.

10 In terms of the capacities and the timings  
11 of the 5054 HH2 equipment, or the B5B equipment, for  
12 those more familiar with that vernacular, we are in  
13 general following what's prescribed in any NEI-06-12  
14 Revision 2, which is the industry guidance for this  
15 equipment, and which has been endorsed by the NRC for  
16 operating reactors. There's a separate revision  
17 that's been endorsed for new reactors.

18 Then once deployed, again in the vein of an  
19 optimistic/pessimistic situation, once deployed, then  
20 we assume that either other on-site capabilities or  
21 off-site capabilities are brought to bear to continue  
22 operation of that equipment to the end of the  
23 simulation.

24 MEMBER STETKAR: And Don, I've forgotten  
25 from the Subcommittee meeting also. Was there some

1       likelihood that that B5B equipment was damaged,  
2       destroyed, unavailable, due to the seismic event, or  
3       was it always presumed to be available, as long as the  
4       operators had this time delay?

5               MR. HELTON: The way we're treating it,  
6       obviously there is some unquantified, in terms of this  
7       study, probability that the equipment would be  
8       damaged, and in the context of this study, that  
9       represents the unmitigated case. The unmitigated case  
10      treats the situation where it is unavailable.

11             MEMBER STETKAR: Okay.

12             CHAIR ARMIJO: Where did the five feet come  
13      from, five feet plus 30 minutes for diagnosis?

14             MR. HELTON: That was simply something was  
15      developed subjectively, and then discussed internally  
16      and viewed to be reasonable. Now as a starting point,  
17      now that we've done the analyses, what we're finding  
18      is is that you could make slightly different  
19      assumptions, and you wouldn't see any large effect in  
20      the results.

21             But that's -- so again, it's somewhat of a  
22      subjective determination --

23             CHAIR ARMIJO: It's a starting point, and  
24      you just -- did you pick it from experience or  
25      something --

1 MR. HELTON: I mean I guess the best way to  
2 characterize it, it was subjective. The intent was to  
3 take into account the situation that AC power is  
4 unavailable. DC power may be unavailable, and --

5 CHAIR ARMIJO: And you don't know what's  
6 going on.

7 MR. HELTON: And now there's a lot going on  
8 at the site. The site we're studying specifically has  
9 provisions in their earthquake response procedures, to  
10 go check the level of the pool, as one of the many  
11 things that they're doing.

12 So but again, this was not intended to be  
13 prescriptive or performance-based in any way. It was  
14 just a logical way, what we felt was a logical way to  
15 approach diagnosis, given that diagnosis is not  
16 defined. It's one of the things that's not defined in  
17 the underlying NEI document.

18 MEMBER STETKAR: Well, and I think the key  
19 is you said you explicitly did not perform a human  
20 reliability analysis. You didn't examine anything  
21 about timing or feasibility or any of that, any of  
22 those issues that you would examine more carefully.

23 MR. HELTON: And then my final point here is  
24 just to point out that we do have these cases of  
25 successful or unsuccessful deployment of the

1 mitigation equipment. But whether or not that  
2 equipment is successful in preventing the release or  
3 decreasing the source term is something that we  
4 attempt to simulate mechanistically.

5 MEMBER SKILLMAN: How would the results be  
6 affected if you were required to consider a 60-day  
7 decay on the third of the core that you just  
8 offloaded, plus 24 or 30 hours of decay on a full core  
9 that you were forced to offload? So now you have 1-  
10 1/3 core arranged in the pool, one full core that's  
11 just freshly discharged, because you've got a casualty  
12 on the primary where you're forced to offload.

13 I understand you to say that's a typical.  
14 But what's typical of all white water reactors is  
15 decay heat, and you can't get away from that. It is  
16 a phenomenon that comes with this technology. So if  
17 you were to be forced to consider the third that you  
18 offloaded 60 days ago, plus the three thirds that you  
19 just irradiated for 60, 90, 100 days, and you  
20 interspersed that new full three-thirds core into your  
21 pool, how significant would the result change?

22 MR. HELTON: I guess I'm not prepared to  
23 answer that quantitatively. We haven't analyzed that,  
24 so I don't have an answer for you. The one thing I  
25 will offer is that we continue to think about this in



1 terms of both the likelihood and the consequence.

2 So now there is at least the potential,  
3 certainly we'd grant there's at least the potential  
4 that the consequences would go up during that  
5 situation, but they also have to be combined with the  
6 fact that we now have had that particular situation,  
7 which is potentially not common, combined with this  
8 event, which is obviously not common.

9 And so again, I can't answer you  
10 quantitatively, which I think is what you would want.  
11 But by the same token I would offer that  
12 qualitatively, you've got competing demands here, in  
13 terms of potential for increasing consequences versus  
14 the decreasing likelihood.

15 MEMBER SKILLMAN: Well, I'm not persuaded by  
16 the idea that it can happen or that it's atypical. It  
17 would seem to me that this would be a scenario that  
18 should be included, just to assure that however one  
19 might look at the path forward for loading these spent  
20 fuels, accommodates even that unlikely event where the  
21 operator is forced to go to a full core offload.

22 Even though that's atypical, I believe  
23 that's almost a design basis that one ought to  
24 consider.

25 CHAIR ARMIJO: But Dick, is that the only

1 option that the operator would have? Just stay put  
2 for a while, keep it in the core. Rearrange your  
3 pools for a favorable offload, you know.

4 MEMBER. SHACK: A short earthquake's not  
5 going to happen.

6 CHAIR ARMIJO: I mean if you just -- the  
7 only option that you point out is that you shut down,  
8 you start offloading immediately, and if you're aware  
9 that there's a vulnerability here, wouldn't you look  
10 at other options?

11 MEMBER SKILLMAN: You'd look at all options.

12 CHAIR ARMIJO: Yeah.

13 MEMBER SKILLMAN: But the one thing I would  
14 do is pull the fuel -- I think removing fuel is one  
15 that one would think of. It would seem to me that's  
16 --

17 CHAIR ARMIJO: Other than what scenario  
18 you're talking about, when you're forced to offload,  
19 you know.

20 (Simultaneous speaking.)

21 MEMBER STETKAR: I think we're getting into  
22 time issues here, but I think you're all dancing  
23 around the fact that this is not a probabilistic risk  
24 assessment for a fuel pool. It is not a full-scope  
25 probabilistic risk assessment. It is a specific

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1 calculation for a specific configuration, under a  
2 specific applied acceleration with specific  
3 assumptions, where there is some variability in those  
4 assumptions, like the optimistic versus pessimistic  
5 conditions.

6 It's not a full-scope risk assessment that  
7 would account for, you know, frequency and variability  
8 and frequency, different types of scenarios, different  
9 types of consequences, and uncertainties in terms of  
10 the frequency of an applied acceleration or the  
11 fragility of any of the equipment. It is not that.  
12 It is simply what it is.

13 MR. HELTON: For time considerations, I'll  
14 keep going. We'll take that under advisement.

15 CHAIR ARMIJO: Keep moving, okay.

16 MR. HELTON: We know that stating  
17 assumptions and limitations are --

18 MEMBER CORRADINI: I'm sorry. I know that  
19 he wants to move on, but because of what John said,  
20 which I agree with, then I'd be very careful to take  
21 selected calculations, then to move on to some  
22 decision-making based on selected calculations.  
23 That's, I think, where we're all kind of going here,  
24 and there's a lot of heads nodding on this. That's  
25 what I think --

1 (Simultaneous speaking.)

2 MEMBER CORRADINI: --relative to the  
3 Subcommittee meeting. Is that fair?

4 MEMBER SKILLMAN: Yes.

5 MR. HELTON: And that's where the bigger  
6 picture issue comes in, in terms of the Tier 3 item,  
7 and I mean that's part of what we're wrestling with  
8 there, is you know, there's a good knowledge base  
9 here.

10 We are probing portions of that knowledge  
11 base, to see if they're generally challenged or  
12 corroborated. But it's that overarching knowledge  
13 base that needs to be used to make a regulatory  
14 decision.

15 Okay. Just real briefly, we've touched upon  
16 many of these, either at Subcommittee or today, but we  
17 know that stating, clearly stating assumptions and  
18 limitations is important. So I just, here, we've put  
19 down a few of them with full core offload, both as an  
20 outage for vessel inspections or in the way that it's  
21 been brought up today.

22 These are not typical for a BWR, and so  
23 because of the way the study is structured, we're  
24 looking at the more typical situation. But we  
25 recognize that as an assumption.

1 MEMBER STETKAR: On the other hand, full  
2 core offloads are typical for pressurized water  
3 reactors during re-outage.

4 MR. HELTON: That's correct, that's correct.  
5 I guess another thing that I would point out there,  
6 that had not really occurred to me or not really sunk  
7 in with me previously, is keep in mind that when we  
8 have the pool in a situation where it is hydraulically  
9 connected with the reactor, so when it's in a  
10 refueling configuration and the gates are down, the  
11 reactor well's flooded and it's hydraulically  
12 connected to the pool, and we're in -- and we're doing  
13 our analysis, for as long as they're hydraulically  
14 connected, we're actually accounting for the decay  
15 heat in both the reactor and in the pool.

16 So in some senses, we are doing a full core  
17 offload, and that as long as they're hydraulically  
18 connected, we're accounting for the decay heat in  
19 both.

20 MEMBER STETKAR: But until you drain down --

21 MR. HELTON: Until they become hydraulically  
22 disconnected --

23 (Simultaneous speaking.)

24 MR. HELTON: Correct, and then it becomes a  
25 reverse to being a spent fuel pool study.

1 MEMBER STETKAR: Yes, that's correct.

2 MR. HELTON: But you know, we felt like --  
3 that's an area where we felt like that was just too  
4 arbitrary and invisible line to draw, when you knew  
5 that decay heat in the reactor, in part heating up the  
6 water in the spent fuel pool.

7 So I want to touch upon multi-unit effects,  
8 because that's a little bit of what we just talked  
9 about. Inadvertent criticality events is something  
10 that we're currently is not within our scope, and  
11 we've already talked about the recovery and repair  
12 aspect. To the extent that we can address some of  
13 these issues and others that we're identifying by a  
14 sensitivity analysis, then we endeavor to do that.

15 CHAIR ARMIJO: Your election to look at  
16 uncertainties via sensitivity studies is because of  
17 the computer codes that you're using, or you just  
18 wanted to provoke Professor Apostolakis?

19 MR. HELTON: Well first of all, you can use  
20 global sensitivity analysis methods, that might not  
21 provoke him. But --

22 CHAIR ARMIJO: No, it would provoke him. I  
23 know that.

24 MR. HELTON: No. At this point, that's not  
25 a part of it that we spent a lot of time focusing on

1 or cataloguing the assumptions and limitations that  
2 we're making, and as we have these thoughts of you  
3 know, hey, this is one we can chase after, once we  
4 have the time, then we're cataloguing that as well.

5 You know, you can have those arguments as to  
6 which one is more efficient or effective at getting  
7 what you're getting at. At the moment, we propose  
8 sensitivity analysis. But it's not an inherent  
9 limitation of the tools codes that we're using, as  
10 demonstrated by the fact that we're doing quantitative  
11 uncertainty analysis as part of the SOARCA project,  
12 using essentially the same tools.

13 MEMBER POWERS: So you just want to provoke  
14 Professor Apostolakis?

15 MR. HELTON: Yeah, sure.

16 MEMBER POWERS: I kind of enjoy that myself,  
17 so --

18 MR. HELTON: Real quickly, I just want to  
19 touch upon the use of MELCOR for spent fuel pool  
20 analysis. This slide is just intended to give you  
21 some reassurance that we didn't enter into this  
22 blindly. MELCOR, as a tool for spent fuel pool  
23 analysis, has been in use for roughly a decade now.

24 As part of the security assessments that  
25 were done post-9/11, we did a large number of separate

1 effects and integral analyses, and we in fact briefed  
2 the ACRS on several occasions on those analyses.

3 In addition to that, we've done limited  
4 comparisons to the COBRA-SFS study, or actually COBRA-  
5 SFS code. We've done some computation fluid dynamics  
6 analysis to support some aspects of the MELCOR  
7 modeling, and there was also an experimental program  
8 that looked at ignition, well looked at hydraulic,  
9 thermal hydraulic and ignition phenomena related to  
10 fuel during a spent fuel pool accident, again to  
11 confirm or modify the use of the code in this context.

12 CHAIR ARMIJO: Don, are you analyzing  
13 channel or dechanneled BWR fuel, or both?

14 MR. HELTON: We are analyzing channeled BWR  
15 fuel.

16 CHAIR ARMIJO: Which probably from a cooling  
17 is not as conservative. Inability to cool it tends to  
18 isolate it from the other. You know, like compared to  
19 your cartoon there of the PWR assemblies, they're  
20 pretty open, unless the poisons --

21 MR. HELTON: For a case where you have a  
22 complete drain down spent fuel pool accident, keep in  
23 mind that the air has to get under the racks and  
24 through the inlet nozzle of the racks and the  
25 assembly. So the channel box can have some effect

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1       there. Keep in mind that these are high density  
2       racks, so they are fairly close-pitched and the rack  
3       walls are closed.

4               So the rack walls, in some respects,  
5       represent an outer channel. So I wouldn't argue that  
6       there would be some effects, but there are some other  
7       factors that would also --

8               CHAIR ARMIJO: So you don't see that as a  
9       big effect, channeled or dechanneled?

10              MR. HELTON: I wouldn't expect it to have a  
11       big effect, because of the closed frame racking.

12              CHAIR ARMIJO: Okay.

13              MR. HELTON: And also keep in mind the  
14       channel boxes add zirconium to the mix. So they have  
15       good and bad effects in that sense.

16              This next slide is just intended to give you  
17       a picture in your head, as to what MELCOR is trying to  
18       represent here. So we have up on the upper right-  
19       hand corner a picture of the spent fuel pool layout  
20       during operating cycle Phase No. 3. So this is post-  
21       outage. The fuel is in a one by four pattern.

22              One of the things that occurred to me might  
23       have gotten confusing at the Subcommittee, the blue  
24       here, in case it's not obvious, is not water. It's  
25       the cold fuel. So and then in terms of orienting the

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1 older fuel, and to some extents we allow the modeling  
2 conveniences to guide that, since that's not the fuel  
3 that's going to have the first order impact on whether  
4 or not you go to release, what the initial release  
5 would look like.

6 Then there are a couple of other figures off  
7 to the side and at the bottom here that just attempt  
8 to show how you take a code like MELCOR and represent  
9 this type of geometry.

10 MEMBER POWERS: One of the features of the  
11 code you're using doesn't solve the momentum equation,  
12 and so if you look at this assembly, you say -- or  
13 this projection, you say gee, this looks to me like a  
14 whole bunch of parallel channels, flow channels.

15 Why is it immune to parallel flow  
16 instabilities, so that I don't need to solve the  
17 momentum equation? In other words, I could have steam  
18 roaring up through one channel and air coursing down  
19 through another channel.

20 The difficulty you have is that once you  
21 establish an air downward flow, it's a vacuum, because  
22 the oxygen component gets completely consumed, whereas  
23 in everything else, the steam reaction produces an  
24 equivalent amount of hydrogen.

25 Why are you immune to parallel flow

1       instability over this large range sludge pattern of  
2       reacting fuel assemblies?

3               MR. HELTON: Let me take a crack at that,  
4       and then Hossein can jump in, if he elects. In terms  
5       of what the overall flow pattern is going to be, and  
6       to what extent you're going to get up or down flow, we  
7       did try to do or we did do computational flow dynamics  
8       analyses, to try to get at that issue, and to look at  
9       the flow in the building, the downflow through the  
10      downcomer area and under the racks, and then upflow  
11      through the assemblies.

12              In general, those analyses showed that you  
13      would set up this -- that if a pool were completely  
14      drained, you would set up a situation where the  
15      downcomer area, in this case the cask area for the  
16      pool, and the gaps between the racks and the pool  
17      walls, will establish that downflow, and that flow  
18      will preferentially go to those areas, and that flow  
19      will preferentially go up through even the colder  
20      assemblies, as well as, of course, the hotter  
21      assemblies.

22              It's not to say that can preclude downflow  
23      through assemblies on the very periphery. But in  
24      general, we didn't see that type of behavior.

25              (Off record comments.)

1           MEMBER CORRADINI:  You're worried about it,  
2           Dana, when there's water above it or once I start  
3           getting to the top of the channel?

4           MEMBER POWERS:  Once you get to the top of  
5           the channels, it seems to me and if it was one  
6           assembly, I think you can argue that the steam flux is  
7           enough, so that you don't have to worry about this  
8           parallel flow instability problem.

9           But now you're talking about many, many feet  
10          of assemblies.  Small fluctuations in the steam flux  
11          will set up, and once you start air being set down and  
12          reacting with an assembly, because the oxygen gets  
13          completely assumed, that becomes a very stable  
14          downward flow.

15          It does tend to preserve itself, and then  
16          you'll have steam roaring up in one area and air  
17          coming down in another area, and it's a very  
18          complicated-looking flow pattern.

19          MEMBER CORRADINI:  What you're really  
20          asking, though, is -- I mean what I think you're  
21          asking is how much of a power difference and hydraulic  
22          difference do you need to cause that to occur?  I  
23          wouldn't expect it to occur, but if I made enough of  
24          a disparity of the power that each one's giving and  
25          the frictional losses, you could get it.

1                   MEMBER POWERS: Remember I had tried to push  
2                   air through a porous plate that looks like this. What  
3                   I find is always I get a downward flow around the  
4                   periphery, and it's just because there's more  
5                   resistance to upward flow there, and so it  
6                   concentrates in the center.

7                   I would expect you have the same thing  
8                   trying to come down. I certainly don't know, but this  
9                   is clearly a highly stylized thing, and in fact having  
10                  air coming down into this system might actually be  
11                  less risky, because you'll promptly burn all the  
12                  hydrogen. You'll get no accumulation of hydrogen in  
13                  this situation, I suspect. But again, I don't know.  
14                  So I just asked.

15                 MEMBER ABDEL-KHALIK: Would you get any air  
16                 flow through these bundles until the entire bundle  
17                 clears, I mean you've got a gap in the bottom?

18                 MEMBER POWERS: Once you get, expose a  
19                 little hot zirconium, it's going to go after air like  
20                 you will not believe. It will create a flow toward  
21                 it.

22                 MEMBER SKILLMAN: But you've got to be  
23                 completely uncovered to get that, though?

24                 MEMBER POWERS: No. All you have to do is  
25                 expose the top.

1 MR. HELTON: We would predict that for a  
2 good portion of -- I mean obviously, we're talking  
3 about after you started to uncover the fuel.

4 MEMBER SKILLMAN: Right.

5 MR. HELTON: While the top I'll say half,  
6 for notional thinking purposes, while the top half of  
7 the fuel is uncovered, but the bottom half, again for  
8 notional thinking purposes, is covered, then we would  
9 predict that you would still get a lot of steam  
10 cooling from the boiling taking place.

11 Once you've lost adequate steam cooling,  
12 then you would have some circulation, as Dr. Powers  
13 was talking about, but you would not set up the once-  
14 through natural circulation cooling until you had  
15 substantially cleared the base plate, as you're  
16 referring to.

17 CHAIR ARMIJO: You mean the whole pool has  
18 to be emptied?

19 MR. HELTON: That's correct.

20 MEMBER CORRADINI: But I think, I'm just  
21 eating. So Sam's, somebody's got to tell us to stop  
22 talking. But it just strikes me that I remember these  
23 calculations for TMI. Let's not talk about today's  
24 latest event. Let's go back.

25 But in TMI, once I had just a little bit of

1 water left, I could again, under different conditions,  
2 I could imagine if I had enough disparity in power or  
3 hydraulic resistance, I could imagine what Dana's  
4 suggesting is possible.

5 I know it's half and half, but a little bit  
6 of water. Then, you're going to get a downward flow,  
7 because as you said, you're going to basically suck in  
8 the gases. It's a quantitative question.

9 CHAIR ARMIJO: I think you'd better note  
10 that and keep moving. We've got -- we're behind  
11 schedule, and we do also have one public speaker.

12 MR. HELTON: I will try to get us there.  
13 Okay, so this is the high density case. Let's take  
14 all the assemblies older than five years out. This is  
15 the low density case. Again, one by four for the most  
16 recently discharged, and just due to physical space  
17 limitations in the pool, you can't put the other two  
18 offloads in a one by four. So we've represented them  
19 here in a checkerboard pattern.

20 Okay, I'll try to -- because we're behind  
21 time, I'll try to move quickly through actually the  
22 highlights of the off-site consequence piece of this.  
23 We are using the Max-2 (ph) code. It is the choice  
24 domestically and in a lot of other places for doing  
25 this type of analysis.

1           It takes its input, the source term and  
2           other aspects of the release from MELCOR. It takes  
3           its inventory from ORIGEN ARP (ph) calculations, and  
4           then uses other site-specific information like weather  
5           and population as inputs, and then outputs,  
6           consequences from an atmospheric release.

7           We are leveraging the SOARCA best practices  
8           as much as appropriate. We've also done an update of  
9           the economic and population data for doing this  
10          analysis, and of course there are also emergency  
11          planning considerations that go into the off-site  
12          consequence analysis.

13          This is just a cartoon that tries to orient  
14          us about the fact that we've got a postulated  
15          radioactive material release from the site. Max-2  
16          takes that release and transports it off-site, and  
17          then it handles things like deposition, including  
18          deposition caused by rainfall, the direct exposure  
19          shine from the plume, as well as exposure from  
20          deposited material, and then exposure from inhalation  
21          and so on.

22          Oops. I'm too far in my notes. Okay, and  
23          then finally in terms of consequence modeling, just to  
24          continue just a little bit more on that, we will be  
25          modeling prompt and latent health effects, and we are



1 following the lead of SOARCA in considering three  
2 different dose response models and planning to report  
3 results for those three different models.

4 Those are the linear no threshold model, the  
5 linear low dose model with truncation at 620 millirem,  
6 and again, with truncation with five rem per year or  
7 ten rem lifetime.

8 In terms of consequence reporting, we're  
9 planning on reporting health effects, again in terms  
10 of early fatalities and latent cancer fatalities, and  
11 also land contamination, in terms of total land, total  
12 square area of land contaminated above the specified  
13 dose level.

14 MEMBER POWERS: I just have to ask. The  
15 Health Physics Society has come out and said not to  
16 quantify below, what is it, 100 millirem?

17 MEMBER CORRADINI: Ten. You're saying below  
18 ten.

19 MEMBER POWERS: Ten millirem? Why isn't  
20 that one of the alternatives?

21 MR. HELTON: It's another one that could be  
22 considered. I will let somebody jump in if I  
23 misspeak, but my understanding, not having been  
24 directly involved, is that that was one of the  
25 sensitivities that was considered for the SOARCA.

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1 MEMBER CORRADINI: I think it's there, isn't  
2 it?

3 MEMBER POWERS: Yeah.

4 MEMBER CORRADINI: I think it's there,  
5 though.

6 (Simultaneous speaking.)

7 CHAIR ARMIJO: It's three HPS.

8 MR. HELTON: Are you talking about why we  
9 don't apply low dose with a truncation at ten  
10 millirem?

11 MEMBER POWERS: I think what they're saying  
12 is that's the one.

13 MEMBER CORRADINI: Okay, that's the one.  
14 Okay.

15 MEMBER POWERS: I just misremembered the  
16 exact number.

17 CHAIR ARMIJO: It's a ten.

18 MEMBER RYAN: Ten rem.

19 CHAIR ARMIJO: Katie?

20 MS. WAGNER: All right. I'm going to try to  
21 do this expeditiously. So of course there will be a  
22 SECY paper that will be submitted in July 2012, that  
23 runs through the plan for the resolution of the  
24 broader item on expedited transfer of spent fuel pool  
25 dry cask storage.

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1           We've been seeking input from the program  
2           offices, and we have been giving briefings for senior  
3           management and Commissioners. We've also been  
4           interacting with the licensee to ensure that the team  
5           understands how our assumption apply to the operating  
6           facility, and we understand that ACRS may write a  
7           letter and we would definitely consider that feedback,  
8           if it were given.

9           A communication plan has been drafted, and  
10          we plan on sending the study results to NRR by the end  
11          of June 2012.

12          MEMBER ABDEL-KHALIK: How do you intend to  
13          communicate all the limitations associated with this  
14          study?

15          MS. WAGNER: You can go ahead.

16          MR. HELTON: In terms of -- let's just talk  
17          about in terms of the June product right now to NRR,  
18          because that's what we're focused on, it's somewhat  
19          our intent to be in keeping with past guidance from  
20          ACRS on research quality. At the moment, our draft  
21          report has a chapter dedicated to stating major  
22          assumptions and limitations.

23          CHAIR ARMIJO: Okay. Is there going to be  
24          a conclusion from this study, other than we need to do  
25          more work? For example, from this study as it's

1 structured now, could you possibly conclude that we  
2 don't see much benefit in unloading the old fuel, from  
3 a safety standpoint.

4 Is that possible? Or we see great benefit,  
5 but a conclusion that you may have to, you know,  
6 expand on its applicability. But for the particular  
7 study that you did, you come to a conclusion.

8 MR. HELTON: Mr. Ruland would like to take  
9 that question.

10 MR. RULAND: Mr. Chairman, Bill Ruland from  
11 ESS. We, of course, the Office of Research is going  
12 to give us the study, and we've formed no opinion yet  
13 about what this is going to tell us. As you've Don  
14 talk about some of the limitations and the Committee's  
15 pointed out some of the limitations of the study, we  
16 recognize, hopefully we recognize what those  
17 limitations are.

18 It's going to be our job to put this in  
19 context with all the other information. So just want  
20 to, you know, that's going to be our job. You know,  
21 we're the Regulatory Office, and as, you know, as you  
22 know, I think that's our job to put it in context.

23 CHAIR ARMIJO: They'll give you results and  
24 you'll draw a conclusion if you can?

25 MR. RULAND: That's correct.

1 CHAIR ARMIJO: Okay, got it. Okay. Any  
2 other comments, questions from the Committee, taking  
3 into account we are a little late and we have a member  
4 of the public. Go ahead, John.

5 MEMBER STETKAR: Yeah, just a quick one,  
6 Don. You mentioned that you're going to carefully --  
7 I think it's vital that you carefully describe your  
8 assumptions. Keep in mind that oftentimes it's  
9 important to explicitly describe what the study is  
10 not.

11 That's a little bit different than saying  
12 what you did, you know, and sometimes people reading  
13 what you did don't necessarily appreciate what wasn't  
14 done. So that's just a constructive sort of  
15 suggestion.

16 MR. RULAND: Right, and like I said, and one  
17 way in which we're hoping to do that again is having,  
18 at least in terms of the internal product that we're  
19 delivering to NRR, having this chapter dedicated to  
20 the major assumptions and limitations.

21 CHAIR ARMIJO: Okay. With that, I'd like to  
22 open the bridge line.

23 MR. LEYSE: Can you hear me?

24 CHAIR ARMIJO: Is this Mr. Leyse?

25 MR. LEYSE: This is Leyse, right.

1 CHAIR ARMIJO: Leyse, okay. Please go ahead  
2 with your comments.

3 MR. LEYSE: Oh, they're all extemporaneous,  
4 based a little bit on what I heard regarding quality  
5 and research. If you look at the slide, it talks  
6 about prior research. ACRS should look into the  
7 quality of that program.

8 I'm going to start off with something that  
9 I'll mention at the very end also. I've asked NRC to  
10 explain why more conventional LOCA studies, such as  
11 the rod bundle heat transfer at Penn State. Why is it  
12 that those studies do not require zircaloy bundles,  
13 such as the spent fuel pool Phase 1 testing? I'll  
14 repeat that later.

15 Starting off with my written stuff, a single  
16 zircaloy tube, sufficiently heated in air, will  
17 smoulder like pot, or somewhat like a cigarette.

18 NRC staff may have discerned that, so they  
19 went to bundle assemblies for the spent fuel pool LOCA  
20 fire research. At the top of the slide, the cross-  
21 section of the 17 by 17 test bundle is something that  
22 I copied and enlarged with another slide that NRC used  
23 at a closed meeting with EPRI last year.

24 Apparently, the NRC now recognizes the  
25 fundamental importance of including the geometry of

1 the stationery zircaloy reactor, in combination with  
2 the thermohydraulic or aerodynamic conditions of the  
3 air in natural circulation for spent fuel pool LOCA  
4 research.

5 From the slide, it is unfortunate that NRC  
6 has not applied similar resources in responding to  
7 Petition for Rulemaking BRM-50-76. Instead, NRC  
8 repeatedly extols this program that cites the role of  
9 reaction kinetics during LOCA.

10 For example, the Leyses' brief presentation  
11 to ACRS Subcommittee on thermohydraulic phenomena,  
12 Monday, October 18th, 2010, asserted that the 2,200  
13 degree Fahrenheit limit for peak cladding temperature  
14 in the LOCA is non-conservative.

15 Mark Leyse and Robert Leyse discussed  
16 Petition for Rulemaking PRM-50-93, which requests that  
17 the NRC revise its regulations to require that the  
18 calculated maximum fuel element cladding temperature  
19 not exceed a limit based on data from multi-rod  
20 assembly severe damage experiments.

21 At that same October 2010 meeting, the  
22 Subcommittee listened for hours of presentations by  
23 rod bundle heat transfer staff. Those presentations  
24 did not include any consideration of the role of  
25 chemical reaction kinetics, and the impact of

1 volumetric hydrogen generation during LOCA.

2 So as I started, I've asked the NRC to  
3 explain why its LOCA studies, such as rod bundle heat  
4 transfer at Penn State, do not require zircaloy  
5 bundles like the fuel pools Phase 1 testing.

6 Finally, maybe the Japanese will lower the  
7 2,200 degree Fahrenheit heat cladding temperature  
8 limit if they probe the NRC's non-conservative  
9 technical review, pertinent to the denial of BRM-50-  
10 76. Thank you. Any questions?

11 CHAIR ARMIJO: Okay. Thank you, Mr. Leyse.  
12 Any questions from the members of the Committee?

13 (No response.)

14 CHAIR ARMIJO: There being no questions,  
15 again I'd like to thank you for your submittal and  
16 presentation, and without any other comments or  
17 questions from the staff, I'd like to thank the staff  
18 for an excellent presentation. We will write a  
19 letter, I'm sure, I'm pretty sure.

20 But with that, I'd like to take a break for  
21 lunch. We're a little late, but we will reconvene at  
22 12:45.

23 (Whereupon, at 11:55 a.m., a luncheon recess  
24 was taken.)

25



## A F T E R N O O N   S E S S I O N

12:44 p.m.

CHAIR ARMIJO: Okay. Let's come to order. The next topic will be the Final Safety Evaluation Report associated with the license renewal application for the Columbia Generating Station, and Jack Sieber will lead us through that. Jack.

MEMBER SIEBER: Okay. Thank you, Mr. Chairman. This afternoon, the full Committee of the ACRS will hear presentations by the staff members of the Division of License Renewal, and the applicant, Energy Northwest License Renewal Subcommittee had a meeting on the Columbia Generating Station, held on October 19th, 2011.

At that time, there were six open items and no confirmatory items from the Safety Evaluation Report. Six open items consisted of first, high voltage porcelain insulators; second, use of future operating experience information; third, upper-shelf energy; fourth, metal fatigue; fifth, core plate rim hold-down bolts; and sixth, fatigue analysis of the polar crane.

The applicant and the staff will explain to the Committee this afternoon the resolution to those open items. We will now proceed with the meeting, and

1 I call upon Melanie Galloway of the Office of Nuclear  
2 Reactor Regulation, to begin.

3 MS. GALLOWAY: Thank you, Mr. Sieber. My  
4 name is Melanie Galloway. I'm the acting Division  
5 Director of the Division of License Renewal, and as  
6 always, we are very pleased to be here today, to  
7 present to you the results of our review associated  
8 with the Columbia license renewal.

9 Before we get started, I'd like to introduce  
10 a few members of the staff that are here in support of  
11 this meeting. First to my left is Mark Delligatti,  
12 who is the acting Deputy Division Director of the  
13 Division. In addition, we have representation of a  
14 number of our branch chiefs.

15 Dennis Morey is our Projects branch chief,  
16 responsible for the Columbia safety review. In  
17 addition, we have with us Raj Auluck and Bo Pham, two  
18 of our technical branch chiefs in the Division.  
19 Michael Marshall, another technical branch chief, was  
20 not able to be here today because of an emergent  
21 technical issue that he's working, but he is the  
22 newest member of our management team in the Division,  
23 and we're glad to have him.

24 In addition, I wanted to note that there is  
25 representation by all of our technical branch staff

1 here, as well as regional individuals on the phone.  
2 Geoff Miller, the branch chief in Region IV, as well  
3 as Greg Pick, the senior inspector, Region IV, are  
4 available via that phone connection.

5 In addition, beyond the staff in the  
6 Division of License Renewal, we have representatives  
7 from other technical organizations in NRR that have  
8 supported this review, including balance of plant  
9 branch, the vessel internal branch, and the electrical  
10 branch.

11 First of all, there are a few things I want  
12 to note before turning it over to the applicant for  
13 their presentation. The first is we want to thank the  
14 Committee for being flexible in terms of the  
15 scheduling of both the Subcommittee meeting and the  
16 full Committee meeting.

17 The original schedule for Columbia was a 22-  
18 month schedule, but in order to accommodate the  
19 requirements of the applicant, in terms of responding  
20 to RAI, as well as some of their on-site scheduling,  
21 we did extend the schedule by seven months. So thank  
22 you for your flexibility in that regard.

23 I do want to note in particular one open  
24 item that was open at the time of the Subcommittee  
25 meeting, and is of course now closed, and that is the

1 open item that had to do with operating experience.  
2 I want to note that, because that is an area of review  
3 that has gotten increased importance for the staff.

4 We recently issued an interim staff guidance  
5 document in March of this year, talking about and  
6 providing additional clarity in the area of operating  
7 experience reviews. We've recognized over time that  
8 this is a very significant area that required more  
9 definition.

10 As more plants get into the period of  
11 extended operation, we recognize the importance of  
12 operating experience in terms of ensuring the  
13 effectiveness of aging management programs. So the  
14 Columbia review was the first license renewal review  
15 that had the full benefit of this additional  
16 codification, which we had provided in operating  
17 experience, and the staff, as well as the applicant,  
18 will go into additional detail, talking about the type  
19 of information that was provided, that allowed us to  
20 close this open item.

21 With that, I would like to turn it over to  
22 the applicant, Dale Atkinson, for their presentation.

23 MEMBER STETKAR: Melanie, before you stop,  
24 you said that there was an ISG just issued in March of  
25 this year?

1 MS. GALLOWAY: That's correct.

2 MEMBER STETKAR: Do you happen to have that  
3 ISG number?

4 MS. GALLOWAY: Sure. It's ISG-2011-05. The  
5 exact title is "Ongoing Review of Operating  
6 Experience."

7 MEMBER STETKAR: Thank you.

8 MS. GALLOWAY: Sure.

9 MR. ATKINSON: All right. Thank you, Mr.  
10 Chairman. Are you ready to begin?

11 CHAIR ARMIJO: Yes sir, all right.

12 MR. ATKINSON: I'd like to introduce myself.  
13 Dale Atkinson representing Energy Northwest, and I  
14 appreciate the opportunity to appear today before the  
15 ACRS and discuss the license renewal application for  
16 Columbia Generating Station.

17 I'd like to take just a moment to introduce  
18 our team. To my immediate left is Don Gregoire,  
19 Manager of Regulatory Affairs, and to his left is John  
20 Twomey, Project Manager for License Renewal.  
21 Additionally, we have several members of our staff  
22 here for support around the room.

23 We've provided an agenda, which we think  
24 will address the closure of the open items and other  
25 topics of particular interest, and with that, Mr.

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1 Chairman, I'd like to draw your attention to what we  
2 have as Slide No. 4. Slide No. 4 is an aerial view of  
3 the Columbia Generating Station and surrounding area.

4 I know many of the members of the ACRS have  
5 been out to visit the site. If I can go back to that  
6 particular slide. One moment. There we go. Okay.  
7 I'd like to point out a few features on this. In  
8 particular, you'll note in the bottom center of the  
9 slide here, Columbia Generating Station itself, the  
10 Hollis Building is the reactor building.

11 To its immediate left is the Turbine  
12 Generator building, and the Rad Waste building is the  
13 shorter structure there. There are several support  
14 buildings around as is typical. To the right over  
15 there is a collection of six four-strap cooling  
16 towers. Immediately above them are the two ultimate  
17 heat sinks, with two spray rings in service. You can  
18 see by the white circles there.

19 As you had towards the top of the picture,  
20 which is actually looking east, at the top of the  
21 picture is the Columbia River. It flows left to right  
22 in this picture, and roughly in the middle of that  
23 shot of the river is the river intake structure, that  
24 provides cooling water to Columbia Generating Station.

25 You'll note in the land that exists between

1 Columbia Generating Station and the river are two  
2 cancelled nuclear plants. I'd like to point out some  
3 elevation features that are not obvious when you look  
4 at this aerial photograph. There is a fair bit of  
5 elevation change.

6 In particular, I point out that the Columbia  
7 River itself has a normal river high water elevation  
8 of 353 feet above mean sea level, and the plant  
9 itself, the area right around the base of the reactor  
10 building, is actually at elevation 441 feet above sea  
11 level. So there's typically an 88-foot delta in  
12 there.

13 I guess I'll also remind the Committee that  
14 Columbia Generating Station is located on the Hanford  
15 Nuclear site, and consequently you can see not a lot  
16 of other features surrounding it there.

17 I draw your attention to the next slide  
18 please, Slide 5. Just a general overview. Columbia  
19 Generating Station is a General Electric BWR Series 5  
20 reactor with a Mark II containment. As I showed in  
21 the picture, the cooling water supply and the plant  
22 circulating water in the ultimate heat sink from the  
23 Columbia River, very nice, clean cool water.

24 The plant is rated at 3,486 megawatts  
25 thermal, and has had an upgrade, which I'll address in

1 the next slide.

2 MEMBER. SHACK: Is that a venting? Is  
3 venting in this Mark II?

4 MR. GREGOIRE: As in hardened vents?

5 MEMBER. SHACK: Yeah.

6 MR. GREGOIRE: We do not have hardened  
7 vents. A brief history, with the construction permit  
8 in 1973; the operating license on December 20th, 1983.  
9 We did conduct a five percent uprate in 1995, and then  
10 applied for license renewal of January 2010, and I'll  
11 just point out our present license is set to expire  
12 December 20th of 2023.

13 With that, I'd like to turn the presentation  
14 over to Don Gregoire. Don?

15 MR. GREGOIRE: Thank you. On Slide 8, it  
16 covers briefly our aging management programs we're  
17 crediting for license renewal. 55 in total; 35  
18 currently existing; 13 enhancements to those; and then  
19 20 additional ones. We do have 71 commitments. 55 of  
20 those are specifically for each of the programs we're  
21 committing to or crediting for this process.

22 On the next slide is a summary of the six  
23 items that were considered open at the time of the  
24 Subcommittee meeting, and I'll touch base on each one  
25 of those rather briefly, and if you have questions,



1 please let me know.

2 The first one is Slide 10, closure of the  
3 open item related to high-voltage porcelain insulator.  
4 Now we have been asked to include this in our program,  
5 and on August 17th, we provided a response to the  
6 staff that we were including these insulators in our  
7 program, and that closed out that item.

8 In regards to the next slide, Slide 11,  
9 operating experience. As Ms. Galloway had mentioned,  
10 Columbia was one of the first in the queue there to  
11 expand on how we were going to communicate use of  
12 future operating experience for modifying or  
13 implementing changes to our aging management program.

14 We had gone through a number of iterations,  
15 teleconferences with the staff, to try to make sure  
16 that we captured the appropriate language in our FSAR.  
17 We implemented a few enhancements to our existing  
18 programs, and we provided responses in December to  
19 close this item with the staff.

20 MEMBER SKILLMAN: Don, I would like to ask  
21 this question please. In the status report that the  
22 ACRS has been provided, the forward-going strength of  
23 your OE program is really tied to your Corrective  
24 Action Program.

25 MR. GREGOIRE: The Corrective Action Program

1 also includes the operating experience program, that's  
2 partnered with that. So it's internal and external,  
3 yes.

4 MEMBER SKILLMAN: Describe to us the  
5 strength of your Corrective Action Program, please.

6 MR. GREGOIRE: Okay. I will note that  
7 during the inspection from the NRC, there was a  
8 comment made on a couple of items that had not been  
9 entered into the Corrective Action Program during the  
10 inspection, due to corrosion issues. Since then,  
11 we've instituted a number of strengths or changes to  
12 our Corrective Action Program and our engineering  
13 walk-downs.

14 I just reviewed the engineering walk-downs  
15 performed for this last quarter. There were a number  
16 of CRs that were written to address issues from leaks  
17 to gasket issues, to a number of things that  
18 demonstrate or prove that we had taken action to make  
19 sure that we're identifying and using Corrective  
20 Action Program to address any signs of aging.

21 We have implemented some changes to our  
22 operating experience program, to ensure that we have  
23 a license renewal implementing coordinator, who sits  
24 on the program to ensure that they evaluate and  
25 identify any new aging issues, and that includes new

1 failures or possibly new, not just failures that are  
2 non-safety related, but failures that are safety-  
3 related.

4 And so we have active involvement with our  
5 License Renewal Committee or our team in the operating  
6 experience, as well as in the Corrective Action  
7 Program. We review all the CRs, condition reports  
8 every day, every working day, to identify those that  
9 would or need to be captured in our aging management  
10 program. So we have done a number of things to  
11 strengthen the program in this regard.

12 MR. ATKINSON: Yeah. Nonetheless, I think  
13 what I'd offer, I do think it's a strong program. So  
14 I don't feel that we're particularly exposed in that  
15 area. We have had external people take a look at it.  
16 We've got a nuclear safety culture assessment underway  
17 this week, which includes a major focus on the  
18 Corrective Action Program.

19 The involvement of all the staff is quite  
20 significant. As Don mentioned, we each get all of the  
21 corrective action items every working day. We go  
22 through them. We have several reviews during the day  
23 in challenge meetings. We keep very detailed metrics,  
24 to make sure that they're resolved in a timely manner,  
25 and then of course are audited not only by the Nuclear

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1 Regulatory Commission, inspected by them, but also by  
2 our Quality staff and outside groups we bring in to do  
3 so.

4 We continue to learn opportunities to  
5 improve the program. But overall, I think the program  
6 is strong.

7 MEMBER SKILLMAN: When you meet to describe  
8 what you've discovered in CAP, what level of senior  
9 management is present?

10 MR. GREGOIRE: Every morning, business  
11 morning, we have an ops management or plant management  
12 meeting that reviews all the condition reports, to  
13 make sure they have the right categorization, the  
14 right ownership and the right urgency associated with  
15 that. That happens on a daily basis in the morning.

16 MEMBER SKILLMAN: Who's involved?

17 MR. GREGOIRE: The managers from most  
18 departments, Operations, Maintenance, Engineering,  
19 Chemistry, RP.

20 MR. ATKINSON: And typically a plant  
21 manager, the site vice president and the chief nuclear  
22 officer are present.

23 MEMBER SKILLMAN: Is that common or --

24 MR. ATKINSON: That is very common at that  
25 daily meeting.

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1 MEMBER SKILLMAN: Thank you.

2 MEMBER SIEBER: Maybe I can ask a question  
3 that gets back to what the issue is. These insulators  
4 are 230 kV insulators.

5 MR. GREGOIRE: These are 500 kV insulators.

6 MEMBER SIEBER: Pardon?

7 MR. GREGOIRE: 500 kV.

8 MEMBER SIEBER: 500 kV insulators, okay, and  
9 they are not located on the station property. They're  
10 located at Ashe substation which, if I read your map,  
11 that Ashe substation is to the east of the major  
12 buildings, and the issue was that you had these five  
13 cooling towers sitting to the south of the station,  
14 maybe a little bit southwest, and the drift from those  
15 cooling towers would impact the Ashe substation, which  
16 is an ultimate station blast out power supply. It's  
17 not the main one.

18 How far away from those cooling towers,  
19 approximately, is the Ashe substation?

20 MR. GREGOIRE: You can see in the image  
21 above here, the cooling towers are south of the plant.  
22 The Ashe substation is at the top of the screen there.  
23 It's about three-quarters of a mile. Now we did have  
24 some experience with some cooling tower drift coming  
25 into our transformer yard, which was just north of the

1 plant.

2 We did some studies early in the 90's that  
3 showed that that drift really was occurring close to  
4 the plant, but wasn't being seen much past that.

5 MEMBER SIEBER: Now your commitment was to  
6 either inspect the insulators or, as an alternative,  
7 just replace on some time-limiting basis; is that  
8 correct?

9 MR. GREGOIRE: Well, not to replace but  
10 clean. Now we did have a test done during this last  
11 refueling outage in the May-June time frame, to test  
12 to see what kind of accumulation was occurring on the  
13 insulators in the switchyard. Very low build-up was  
14 identified during, in those tests.

15 We plan to have a PM that's conducted about  
16 once every eight years, which is consistent with the  
17 transmission organization, Bonneville Power  
18 Administration, who owns that switchyard, to make sure  
19 that we go and reevaluate this buildup.

20 MEMBER SIEBER: Okay.

21 MR. ATKINSON: I think the issue surrounding  
22 the corrective action program as it pertains here came  
23 up because we ultimately ended up including this  
24 action that wasn't there originally, to go do this  
25 inspection out at the Ashe substation.

1           We actually have an individual in the room  
2           that was involved in the evaluation that was done in  
3           the 90's, to figure out where to go or how far out  
4           this was problematic. Basically, we concluded we  
5           didn't need to do anything all the way at the Ashe  
6           substation.

7           MEMBER SIEBER: The projects are desert --

8           MR. ATKINSON: Right. It's desert, and it's  
9           quite a ways to Ashe. Nonetheless, we were unable to  
10          recover the test data that showed the actual fall-off  
11          of material as you approached it. So we thought it  
12          prudent to go ahead and add the preventive maintenance  
13          activity to go look out there at it, and in fact the  
14          tests to date has confirmed that it does not appear to  
15          be problematic out there.

16          MEMBER SIEBER: Yeah. Well, I concluded  
17          that the chance of significant accumulation was  
18          probably not there, but the corrective action would  
19          take care of it anyway.

20          MR. ATKINSON: Absolutely.

21          MEMBER SCHULTZ: Yes. So Don, it's issues  
22          like this that, based upon the improvements to the  
23          Corrective Action Program, you would feel would be  
24          identified by the station staff, and put into the  
25          Corrective Action Program?

1 MR. GREGOIRE: This was a little bit unique,  
2 in that there's no history of any kind of failures in  
3 the Ashe substation, and the staff asked us to look a  
4 little bit beyond it.

5 If you're referring to our ability to  
6 identify issues that may come up during our current  
7 plant, I mean there's a number of things that we're  
8 doing right now. But I'm not sure. Are you referring  
9 to this insulator issue or --

10 MEMBER SCHULTZ: That, plus those that  
11 you're about to discuss, the other issues as well.  
12 But I'm -- given the going-forward approach associated  
13 with license renewal, that we're looking for the  
14 connectivity between your Corrective Action Program  
15 and then, on inspection and discussion, what was  
16 identified by the staff.

17 Obviously, the Corrective Action Program is  
18 the much better way to identify these issues and  
19 address them.

20 MR. GREGOIRE: Now I will tell you that we  
21 provided aging management training to our Engineering  
22 staff in April of this year. During the refueling  
23 outage, which occurred right after that, we had a  
24 number of items that were identified, issues with  
25 corrosion or wear, that were entered in the corrective



1 action process.

2 So you could actually see or demonstrate  
3 that the engineers got the message. They understood  
4 it, and they were using the corrective action process  
5 to drive change. We had quite a few that were  
6 identified during the process of the outage,  
7 especially because you're much more exposed to  
8 equipment that's torn apart and what-not.

9 MEMBER SIEBER: I would point out that in my  
10 experience, insulators fail even if they're not fouled  
11 from the environment. It depends on the porosity, the  
12 insulation material and so forth. So this inspection  
13 is not a waste of time for this.

14 MEMBER ABDEL-KHALIK: So typically, how many  
15 CRs are written per year at your plant, just a  
16 demonstration of people's willingness to write CRs?

17 MR. GREGOIRE: I don't have the total  
18 numbers, but it's in the thousands. I would just be  
19 guessing. It would be somewhere between five to ten  
20 thousand CRs that are written a year. Now we have an  
21 inspection that's --

22 MEMBER ABDEL-KHALIK: 5,000 would be on the  
23 low end?

24 MR. ATKINSON: Yeah, but I think it's closer  
25 to ten. You have to understand that we, a few years

1       ago, incorporated the work orders and everything to go  
2       into that. So it's a very large database of  
3       information. But it is --

4               MR. GREGOIRE: I apologize. I don't have  
5       the exact number, but I will say that we get a regular  
6       inspection from the NRC staff, both from the  
7       residents and the regions, and we've had very few  
8       violations with our Corrective Action Program over the  
9       years.

10              MR. TWOMEY: But I do know, speaking back to  
11       when they were separated as problem evaluation  
12       requests. So you could count the numbers. We were up  
13       around between eight and ten thousand.

14              MR. GREGOIRE: That's what I recall too.

15              MEMBER ABDEL-KHALIK: Very fine.

16              MEMBER SIEBER: What's the average time for  
17       you to clear an open item for your corrective action  
18       folks?

19              MR. GREGOIRE: So the priority with  
20       corrective actions is it's in accordance with safety  
21       significance. Those that are much more safety-  
22       significant are resolved in much quicker time. Those  
23       that are not take much longer. So I don't have a  
24       number for you.

25              MR. GREGOIRE: We do use a very typical

1 industry metric, you know, for having corrective  
2 actions closed in 120 days. We track all of them.  
3 But we do have some that are tagged to long-term  
4 program changes or even outages. So we try and  
5 separate those out, so the staff doesn't become numb  
6 to seeing a very long-term corrective action item.

7 MEMBER SIEBER: Well that -- the big numbers  
8 concern me, because that's the attitude that we'll get  
9 forward.

10 MR. ATKINSON: And that's why we've spent a  
11 lot of time making sure that the metrics keep it in  
12 front of people and the different reviews.

13 MR. GREGOIRE: And in the morning meeting  
14 with the management team, they identify the different  
15 levels of classification for those that are alpha or  
16 Bravo level. Those get immediate attention, because  
17 they have immediate safety significance, and they get  
18 resolved much, much quicker than those of the Charlie  
19 or Deltas.

20 MEMBER SIEBER: Thank you.

21 MR. GREGOIRE: I'd like to move on to the  
22 next item on Slide 12, which is the closure of our  
23 item related to upper-shelf energy. In the  
24 information we had provided the staff, there was  
25 questions that were raised about the technical basis

1 for initial transverse upper-shelf energy and copper  
2 content for certain instrument nozzles that were in  
3 the belt line region.

4 We have since provided that information to  
5 the staff, and satisfied their concerns for the  
6 technical basis.

7 The next item is associated with metal  
8 fatigue. In this area, there was -- the standard  
9 review plan was revised, challenges our licensees to  
10 consider other possible locations.

11 That may be more limiting than those  
12 identified in NUREG-6260. Our staff was aggressive in  
13 going out and evaluating those. We took the action to  
14 complete the analysis. We actually had, were audited  
15 by the staff in November of this year, and we provided  
16 closure on a final item in January on this subject.

17 There were no items that were identified  
18 that were more limiting than those that we had  
19 previously provided in our application, and then all  
20 values were less than the 1.0 of the SAME code.

21 The next item is associated with the closure  
22 of the subject of lower core plate rim hold-down  
23 bolts. We were asked to provide information with  
24 regard to TLAA and the hold-down bolts. We have  
25 included information in our application for aging

1 management review on these bolts, and we all  
2 dispositioned this as a TLAA with classification  
3 Charlie One Triple I, which means that the effects of  
4 aging will be adequately managed for the period of  
5 extended operation.

6 MEMBER SKILLMAN: Don, let me ask a question  
7 about this. This whole issue seems to tie back to the  
8 presence or non-presence of the core plate wedges.

9 MR. GREGOIRE: That's correct.

10 MEMBER SKILLMAN: And originally, you  
11 communicated that you had these wedges in place, and  
12 later discovered that you did not?

13 MR. GREGOIRE: That's correct.

14 MEMBER SKILLMAN: Was there any 50.9  
15 consequence for that activity?

16 MR. GREGOIRE: Well, this was initial  
17 license information. Back in 1983, it was our  
18 understanding that these wedges had been installed.

19 It was something we did communicate to the  
20 staff in accordance with 50.9, to make sure that they  
21 understood, especially when we did an evaluation in  
22 the last outage, we actually sent a camera down there  
23 to verify that and found that they were not there. So  
24 we communicated right away with the staff, both with  
25 the resident and with NRR.

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1           MEMBER SKILLMAN: Okay. Let me go a little  
2 bit further on this. So as I envision this mechanical  
3 coupling of these bolts, I can imagine some movement  
4 of the core thermal shield complex that's causing  
5 these bolts to either fatigue or simply loosen.

6           How will the treatment of the fatigue,  
7 remaining fatigue life of those bolts be handled once  
8 you install the wedges, which is the commitment that  
9 you have made? What I'm really wondering about is how  
10 you calculate the usage to date, because once the  
11 wedges are installed in theory, that usage decreases  
12 significantly?

13          MR. GREGOIRE: Right. The wedges prevent  
14 lateral and vertical motion. We do have a study that  
15 was done to evaluate it, and Steve Richter is our lead  
16 on this, but we do have a slide showing the sequence.

17          MR. RICHTER: Steve Richter, Energy  
18 Northwest Engineering. Slide 41, I believe. No, 42.  
19 I'd like to see 41 first, just to get an idea of where  
20 we're at. Thank you. So this is a drawing of our  
21 reactor pressure vessel. You see the core plate is in  
22 the middle there, and the insert is the bolt itself.

23          There's 30, 32 or 30 bolts around the core  
24 plate itself. You've got all the way to the active  
25 fuel line top of it. They prevent the lateral motion.

1 We had a study done, as part of our deviation when we  
2 found the problem, entered it into our Corrective  
3 Action Program, had the study done and updated, to  
4 make sure that the pre-load and life of the bolt would  
5 neither exceed our current license.

6 As we committed to, we will have it  
7 addressed two years prior to the period of extended  
8 operation. Now fatigue wasn't identified as one of  
9 the failure mechanisms. Relaxation, loss of fuel load  
10 and cracking are the mechanisms of concern, according  
11 to the BWR VIP 25 (ph), excuse me, boiling water  
12 reactor Vessel Internals Program dash 25 guidelines.

13 CHAIR ARMIJO: Which is the mechanism of  
14 greatest concern, stress corrosion cracking --

15 MR. RICHTER: Stress corrosion cracking.

16 CHAIR ARMIJO: And you're addressing that  
17 with hydrogen water chemistry, noble metals, things  
18 like that?

19 MR. RICHTER: True, but now you can go to  
20 the next slide and see.

21 CHAIR ARMIJO: Okay.

22 MR. RICHTER: What you see here is the loss  
23 of life. Zero percent losses, they're at the bottom,  
24 and then at 40 years, shortly after 40 years, it drops  
25 off quickly, assuming that five years into it we have

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1 a crack and it grows.

2 This study does not take credit for hydrogen  
3 water chemistry. But we do have it, and we are  
4 mitigating hydrogen water chemistry. So that's an  
5 added conservatism in the calculations.

6 MEMBER. SHACK: And how many of those bolts  
7 do you need?

8 MR. RICHTER: I have not seen the  
9 calculation. I don't know that we've done the  
10 calculation to determine how many we need. But this  
11 shows that it's there, and if you assume, I believe  
12 the assumption in the analysis is that all of them  
13 have a crack five years since service initiates, and  
14 begins growing. You still have plenty of margin with  
15 pre-load.

16 MEMBER SKILLMAN: Does this assume the  
17 wedges are or are not installed?

18 MR. RICHTER: Are not installed. Our design  
19 is no wedges.

20 MEMBER SIEBER: Now when hydrogen water  
21 chemistry first came out, you did not employ it  
22 because of other materials --

23 (Simultaneous speaking.)

24 MR. ATKINSON: That's correct. We had a lot  
25 of copper. It was a challenge at that time to do



1 that.

2 MEMBER SIEBER: And you changed materials in  
3 all places?

4 MR. ATKINSON: And the biggest key to the  
5 chemistry change was the replacement of the main  
6 condenser frankly, to remove the copper, replace the  
7 metal with titanium, a very large project, and then as  
8 well as noble metals, you know, the advent of that  
9 chemistry. The tool list helps quite a bit as well.

10 MEMBER SIEBER: Okay.

11 CHAIR ARMIJO: Are those bolts inspectible?  
12 Have you -- not really?

13 MR. ATKINSON: Not really, but Steve can  
14 talk to that. That's the challenge here.

15 MR. RICHTER: You can look at the top of  
16 them. The industry requirement is that you either  
17 perform UT, or you inspect the bottom to make sure  
18 they haven't fallen out. Neither one of those is a  
19 feasible inspection. So that answer is no, they are  
20 not.

21 MEMBER SIEBER: Can't you UT down through  
22 the top of the bolt?

23 MR. RICHTER: I couldn't hear.

24 MR. GREGOIRE: Can you UT though the top of  
25 the bolt head?

1 MR. RICHTER: No, you can not. There's a  
2 keeper on top which prevents effective UT. The  
3 industry is looking into that.

4 MEMBER. SHACK: You can't even identify  
5 broken bolts?

6 MR. RICHTER: We cannot, other than -- yeah.

7 MR. ATKINSON: So this is -- as you've honed  
8 in on, here's the challenge we have to deal with, as  
9 we face the end of the 40-year lifetime, and plan for  
10 the wedge and the securing going forward, which is why  
11 we have this commitment to work that out, and working  
12 with the BWR owner's group to resolve.

13 CHAIR ARMIJO: What is a bolt material?  
14 High strength alloy? It's not just plain old 316 --  
15 (Simultaneous speaking.)

16 MR. RICHTER: Stainless steel, I believe.  
17 304 stainless steel.

18 CHAIR ARMIJO: I hope it isn't 304.

19 MR. ATKINSON: We can check on that, and  
20 while they're getting that specific, I did get some  
21 information back on CRs, our condition reports. We  
22 are running about 12,00 condition reports per year.  
23 50 percent of all of them are closed within 30 days.  
24 So we invest quite a bit of time and effort into that  
25 Corrective Action Program.

1 MR. GREGOIRE: If you would like, we can  
2 move on, and then --

3 MEMBER SIEBER: Did you pass over the upper-  
4 shelf energy?

5 MR. GREGOIRE: We had, just prior to metal  
6 fatigue, we talked about upper-shelf energy yes, back  
7 on Slide 12.

8 MEMBER SIEBER: That was just a technical  
9 argument that --

10 MR. GREGOIRE: Yes. It was just making sure  
11 we had given them, the staff, the technical  
12 information that supported our conclusion for what the  
13 copper content was and what the initial upper-shelf  
14 energy was.

15 MEMBER SIEBER: Great.

16 MR. RICHTER: Excuse me, Dale?

17 MR. ATKINSON: Yes.

18 MR. RICHTER: I do recall that the bolting  
19 material and the nut are SA-193 and 194.

20 CHAIR ARMIJO: Okay. Bill, translate that  
21 to me. Is that -- I don't know what that is.

22 MR. RICHTER: It's 304.

23 CHAIR ARMIJO: It's 304, yeah. So it's  
24 plain vanilla.

25 MEMBER. SHACK: Geez, stress relaxation.

1 CHAIR ARMIJO: That's just calculated.

2 MEMBER. SHACK: Well, but I'm surprised that  
3 you would use 304 for something where stress  
4 relaxation was the critical issue.

5 MR. GREGOIRE: All right, next slide, John.

6 MEMBER ABDEL-KHALIK: So what would be the  
7 impact of a broken bolt falling into the bottom of the  
8 vessel?

9 MR. ATKINSON: Well, I'll tell you what.  
10 While Steve gathers his thoughts, you know, I've seen  
11 quite a few different lost part analyses conducted for  
12 boiling water reactors, formerly for GE and now at  
13 Columbia Generating Station, and my experience is a  
14 component of that kind of mass is going to settle to  
15 the bottom of the vessel around the subtubes.

16 The biggest challenge would be whether the  
17 debris ended up settling in the bottom head drain, and  
18 caused some sort of blockage down there, either a flow  
19 problem or an isolation problem. Is that the type of  
20 information you wanted?

21 MEMBER ABDEL-KHALIK: Right. I was just --  
22 if you had actually looked at that, due to the fact  
23 that you can't inspect them.

24 MR. ATKINSON: Right. We have been in the  
25 bottom of the vessel invert, but that's not a very

1 frequent activity to go down there. It's a difficult  
2 inspection to perform. So it's been a number of years  
3 since we've been in the internal side of the vessel  
4 invert.

5 We do not have any signs of flow degradation  
6 in the bottom head drain flow or any other observable  
7 delta there.

8 CHAIR ARMIJO: Well Dale, has there been any  
9 operating experience on 5's with the same hold-down  
10 bolt design, either a failure or open bolts?

11 MR. ATKINSON: I think for that, I am going  
12 to need the BWR VIP representative. So Steve.

13 MR. RICHTER: Due again with the wall, I  
14 couldn't very well hear you.

15 CHAIR ARMIJO: Yes. There's a question,  
16 operating experience in the same bolts in the BWR-5?

17 MR. RICHTER: Yes. There's quite a few that  
18 have this same configuration. There are no reports of  
19 any failed bolts.

20 CHAIR ARMIJO: And no one has been able to  
21 inspect them or remove one for whatever reason? It's  
22 just --

23 MR. RICHTER: To the best of my knowledge,  
24 all that has been done is a visual from on top. A few  
25 utilities have done that. Of course, we are

1 committed, all of us, if the opportunity arises and  
2 you're down there, to try and look at everything in  
3 the area.

4 I do not recall any report of anybody being  
5 able to capture a bolt. But there's been no OE of a  
6 failed bolt either.

7 CHAIR ARMIJO: Okay.

8 MR. GREGOIRE: And there are a number of  
9 plants that it's similar.

10 CHAIR ARMIJO: Yeah.

11 MR. GREGOIRE: The last item is Item 15,  
12 associated with fatigue analysis for power crane.  
13 Just as a point of clarification, we have an overhead  
14 crane, not a puller crane, that you would typically  
15 find with a dome. But nonetheless, we were asked  
16 about whether there was a TLA, and we agreed with the  
17 staff, that there should be a TLA associated with this  
18 crane and all of our in-scope cranes.

19 So we have included it in our TLA analysis  
20 and concluded that it meets the criteria of Charlie 1-  
21 I, which is remains valid for the period of extended  
22 operation, and we provided that information to the  
23 staff back in October.

24 So with that, that is the last of the items  
25 that were identified as being open, and if there's no

1 further questions, I'll turn it over to John Twomey to  
2 discuss any of the subjects that were raised during  
3 the Subcommittee meetings, if preferred.

4 MR. TWOMEY: So after we left the  
5 Subcommittee meeting, we had six topics that we were  
6 required to submit additional information to the  
7 Subcommittee. There was on the slide, we submitted  
8 the closure information December of 2011, and the next  
9 topic I'd like to talk about is implementation.

10 You know, we are a few years out from our  
11 period of --

12 MEMBER STETKAR: John, hold on.

13 MR. TWOMEY: Yes.

14 MEMBER STETKAR: Excuse me. You said you  
15 submitted closure information on those six items last  
16 December?

17 MR. TWOMEY: Yes, I did.

18 MEMBER STETKAR: Huh.

19 MEMBER RAY: To the staff?

20 MR. TWOMEY: To the staff, yes.

21 MEMBER STETKAR: Huh. I don't think we've  
22 seen that. I was going to try to follow up on some of  
23 these six, to see what the resolution was, and I was  
24 surprised to hear that --

25 MEMBER SIEBER: It's in Kent's status report

1 on the SER, but it's pretty high level --

2 MEMBER STETKAR: Yeah, high.

3 MEMBER SIEBER: But there is an exchange of  
4 mail back and forth on each one of these, and you can  
5 go and look at that, with some of it, not all of it.

6 MEMBER STETKAR: Okay. I missed that.  
7 Thanks.

8 MR. TWOMEY: All right. Moving on, the  
9 final topic we were going to cover was implementation  
10 overview. The implementation activities anticipating  
11 moving forward, have been incorporated into Columbia's  
12 long-range plan.

13 We're looking at this being approximately  
14 11, 12 years out as an advantage to getting our  
15 program set up, so we run right into them, the full  
16 ten years prior to the period of extended operation.

17 Some of the items we've done, completed, are  
18 an implementation coordinator on our staff has been  
19 identified. That is myself. I will transition from  
20 the program manager into the implementation  
21 coordinator. We've also issued, approved the  
22 implementation procedure.

23 This is the first procedure to outline roles  
24 and responsibilities for the implementation  
25 coordinator, aging management program owners and



1 management staff that would be involved with that, get  
2 everybody on board and ahead of the ball here.

3 Then the next item will be development of  
4 the AMPS, of the Aging Management Programs. As Don  
5 mentioned before, we have 35 existing, 13 required  
6 enhancement and 20 new. Our target is to have all  
7 that work done by the end of 2013. That aligns with  
8 we will then roll into our ten years prior to the  
9 period of extended operation.

10 So we'll have basically the full time frame  
11 to fulfill all our commitments and obligations under  
12 aging management, prior to entering the period of  
13 extended period. We've also actively participated in  
14 the License Renewal Implementation Working Group for  
15 the last couple of years.

16 And we've benchmarked other sites currently  
17 through the Implementation Working Group, and we will  
18 go do benchmarking. This is at other sites that are  
19 ahead of us in the process. This way, we can gather  
20 lessons learned from those that have gone before us  
21 and done well. With that, I'd like to turn it back  
22 over to Dale for his program comments.

23 MR. ATKINSON: All right. Thank you, John.  
24 Well in closing, Mr. Chairman and distinguished  
25 members of the ACRS, I do appreciate the time to come

1 here today and discuss Columbia's license renewal. I  
2 will point out that the plant itself is well-funded,  
3 well-supported, and we have a community of support in  
4 south central Washington.

5 As a point I wanted to make, I did review,  
6 since the Subcommittee the long-range plan, just to go  
7 over for myself on the level of investment in the  
8 plant that's planned for the next ten years as a  
9 typical item, and the next fiscal year, which for us  
10 begins in July, we'll be investing \$270 million in the  
11 operating and maintenance of Columbia.

12 In addition, there's another \$50 million in  
13 capital projects. So it's a very, I think, well-  
14 invested in ongoing concern, many of these programs.  
15 We had some discussion last time about the time out  
16 for us, given that the license doesn't expire until  
17 2023.

18 We have taken advantage of that, to actually  
19 go out, do some inspections and basically get our feet  
20 wet in the process of running the plant for the  
21 additional 20 years. I would like to recognize a lot  
22 of the hard work that has been put into this process,  
23 both by the team at Energy Northwest and the NRC  
24 staff.

25 We at Energy Northwest do understand our

1 responsibility and are committed to the long-term safe  
2 and reliable operation of Columbia Generating Station.  
3 With that, Mr. Chairman, I'd like to turn it back over  
4 to you, sir.

5 CHAIR ARMIJO: Yeah. I think we have the --  
6 Jack, it's the staff.

7 MEMBER SIEBER: The staff's review.

8 MEMBER. SHACK: Just a quick question.

9 MR. ATKINSON: Yes.

10 MEMBER. SHACK: The wedges are a complete  
11 substitute for the bolts. That is, once the wedges  
12 are in, you could have complete failure of the bolts?  
13 This is really a lateral motion kind of thing?

14 MR. RICHTER: Yes. That's the discussion  
15 we've had, yes. Steve, confirm that please?

16 MR. RICHTER: Yes, that is absolutely  
17 correct. The wedges replace the function of the bolt.

18 MEMBER. SHACK: Okay.

19 MEMBER SCHULTZ: Dale, in your plans over  
20 the next ten years, is there any plan for an  
21 additional power uprate?

22 MR. ATKINSON: We do not have an additional  
23 power uprate planned right now. We continue to do  
24 cost-benefit analyses, and right now for the power  
25 condition in the Northwest, it simply doesn't pencil

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1 out. For us, the next change, I pointed out in the  
2 presentation, we've done a five percent uprate.

3 For us, the next uprate is substantial in  
4 the amount of equipment that has to change. So as  
5 we've gone through kind of a living program of  
6 obsolescence and replacement, we've tried to retain  
7 the option on all the equipment that's replaced, to  
8 support an uprate should we choose to do it some day.

9 For example, we replaced the main generator  
10 rotor last outage, and provided a rotor that has the  
11 capabilities to support an uprate. Additionally, the  
12 condenser, same type of situation. But right now, the  
13 rest of the steps necessary to conduct an uprate  
14 simply aren't penciling out as cost beneficial.

15 MEMBER SCHULTZ: With regard to the issue on  
16 the bolt evaluation, and the wedge addition, is there  
17 -- what is the limiting factor that is affecting  
18 schedule? The commitment, what I heard was that the  
19 commitment was by 2021, this would be addressed?

20 (Simultaneous speaking.)

21 MR. ATKINSON: No later than two years prior  
22 to that.

23 MEMBER SCHULTZ: What's affecting schedule  
24 for implementation at this point?

25 MR. ATKINSON: Steve, why don't you address

1 that? I'll give you a high level view. It's the  
2 challenge of the solution, but go ahead.

3 MR. RICHTER: It's the challenge of the  
4 solution. I believe the design for wedge installation  
5 has been done before at other utilities. Looking at  
6 it from the process, it's the term of identifying,  
7 planning, budgeting and implementing, and if you do a  
8 cycle approach, that's a couple of cycles right there.

9 We are also working with the industry, to  
10 see if this is not a manufacturer problem. In other  
11 words, we have the analysis already the industry is  
12 committed to, by 2015. So whether this is a problem  
13 that has to be resolved.

14 In other words, there might be enough life  
15 to go 60 years, and every electrical power resurgence  
16 through the BWR vessel during this inspection program  
17 is committed to having a document out on the streets  
18 by 2015.

19 So we'll see what that says, and then  
20 planning our own destiny and methodically approaching  
21 this.

22 MR. ATKINSON: Yeah. From my own  
23 experience, it's not the most elegant solution. So  
24 while it's workable, we'd like to see where the  
25 development of the program goes, to see if that's the

1 path to take. Beyond that, we've installed wedges and  
2 other things in the past, and the industry has a fair  
3 bit of experience doing, putting other mechanisms in  
4 there.

5 And, you know, very change has its  
6 challenges, either on that day or some day down the  
7 road. So we just want to spend some time with the  
8 industry, and make sure we provide the best solution.

9 MR. RICHTER: And if you recall, this is by  
10 two years prior due. It doesn't mean we'll wait  
11 until the last year necessarily.

12 MR. ATKINSON: Right.

13 MEMBER SCHULTZ: Thank you for the  
14 additional explanation.

15 MEMBER SIEBER: Okay. Any other questions?

16 (No response.)

17 MEMBER SIEBER: If not, I think we're ready  
18 for the staff presentation. Thank you very much,  
19 gentlemen.

20 (Pause.)

21 MS. GALLOWAY: I'd like to introduce the  
22 staff who are going to be presenting today. Arthur  
23 Cunanan is our project manager for the Columbia safety  
24 review, and he'll be giving the presentation. Angela  
25 Buford is also a project manager in our organization,

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1 and she will be handling the slides.

2 Matt Homiack is a mechanical engineer in our  
3 organization, and he was the initiator of the  
4 operating experience interim staff guidance document  
5 and we'll be talking about that open item, and Dr.  
6 Allen Hiser is our senior level staff, and I'm sure  
7 the Committee is well familiar with Dr. Hiser. He's  
8 usually here at our ACRS presentations. So with that,  
9 I'll turn it over to Arthur.

10 MR. CUNANAN: Thank you, Melanie. Good  
11 morning Chairman and members of the ACRS staff. My  
12 name is Arthur Cunanan, and I'm the project manager  
13 for the Columbia Generating Station license renewal  
14 application.

15 I'm here to discuss the staff's review of  
16 the Columbia license renewal application, as  
17 documented in the safety evaluation report. Melanie  
18 has made introductions of who is at the table. Also  
19 seated in the audience are members of the technical  
20 staff, who participated in the review of the license  
21 renewal application, or were at the audits conducted  
22 at the plant.

23 Also Greg Pick and Geoff Miller from Region  
24 IV is available on the phone. As always, you can ask  
25 questions at any time during the presentation. Here

1 is an outline of today's presentation. This is an  
2 overview of Columbia Generating Station. We received  
3 a regional administrator's letter, and have issued the  
4 final SER.

5 For internal corrosion of buried piping,  
6 this slide addresses a takeaway from the ACRS  
7 Subcommittee meeting. The ACRS questioned the staff's  
8 position on the applicant's not including additional  
9 inspections of internal surfaces of buried piping,  
10 when they had operating experience of leakage due to  
11 internal corrosion.

12 After the ACRS Subcommittee meeting, the  
13 applicant conducted a search of plant-specific  
14 operating experience and determined that the buried  
15 pipe, which leaked, was out of scope PBC piping, and  
16 that the failure was not due to internal corrosion.

17 Applicant then amended the LRA AMP and the  
18 staff revised the LER to reflect the amended letter in  
19 the final SER. The staff has confidence that the  
20 aging effect of internal corrosion of buried and  
21 above-ground piping is appropriately age-managed by  
22 several programs, such as the fire water program and  
23 open cycle cooling water program.

24 Given that the ACRS Subcommittee meeting  
25 expressed interest in internal corrosion of buried



1 pipe, we would like to take this opportunity to  
2 discuss the following. There have been two examples  
3 of recent industry operating experience noted by the  
4 staff during LRA AMP audits and other plants that are  
5 requesting license renewal.

6 One plant had pervasive microbiological  
7 influence corrosion MIC, and another had extensive  
8 selective leaching of aluminum bronze. The staff has  
9 developed extensive RAIs to address these issues.

10 Given these examples of operating experience  
11 related to internal corrosion, the staff is currently  
12 developing an ISG, and expects to issue the draft ISG  
13 by summer of 2012.

14 MEMBER STETKAR: How is that -- I'm glad you  
15 had a slide. I don't have a copy of your slides here,  
16 so I'm glad you brought this up, because it was one of  
17 the questions that I had, and I was trying to do some  
18 real-time scanning here.

19 I think the reason we brought this up at the  
20 Subcommittee meeting was, as you've explained, the  
21 previously-cited operating experience did note that  
22 there -- did cite, apparently incorrectly, internal  
23 corrosion as a source of the observed failures.

24 In particular, this applicant has not  
25 proposed any volumetric or internal inspection of any

1 of the buried piping; is that correct? They're only,  
2 not only going to do the excavation of a sample and  
3 internal inspection of their buried piping, right?

4 MR. CUNANAN: Yes.

5 MEMBER STETKAR: When you develop this ISG  
6 to be developed, how will that apply to already-issued  
7 license extensions?

8 MR. CUNANAN: I'll have John Wise talk to  
9 you about this.

10 MR. WISE: Good afternoon. John Wise,  
11 License Renewal staff. This ISG was brought up to  
12 address specifically plants that have pervasive  
13 operating experience. So what it's addressing is when  
14 we run across plants that have internal corrosion  
15 issues, to date we have been using the RAI process to  
16 get some competence that their programs are going to  
17 manage those issues.

18 And so as Arthur describes, this ISG is  
19 intended to take us away from the RAI process, to  
20 provide proactive guidance, you know. As plants  
21 experience this, we're inspecting them. You know,  
22 using this ISG, we're going to give them guidance to  
23 how to craft a plant-specific program to address  
24 pervasive internal corrosion.

25 Now in this case, and for Columbia, we don't

1 have that issue. So specifically this ISG isn't  
2 applicable in this case. But we thought it was  
3 appropriate at this time to bring it up, so you're  
4 aware that we keep track of these things, and we do  
5 handle it with RAIs. But in the future, we are going  
6 to have some guidance, provide more direction.

7 MEMBER STETKAR: Thanks. That helps a lot.

8 MS. GALLOWAY: And John, in response to your  
9 question as well, this is an issue, then, that marries  
10 up quite nicely with our recent ISG and operating  
11 experience, because for plants that have already been  
12 licensed-renewed, to the extent that they encounter  
13 operating experience, we would fully expect them to  
14 analyze it.

15 If they determine they need to do something  
16 more than what they're already doing, the ISG then  
17 would be an appropriate guidance document to them,  
18 that we would expect them to use, to continue to  
19 demonstrate to us that they're effectively managing  
20 aging.

21 MEMBER STETKAR: Yeah, and that makes sense.  
22 Thanks. That helps a lot. Okay. Thank you, John.

23 MEMBER RYAN: Arthur, one other just follow-  
24 up question, just for my information. You mentioned  
25 that there a biological brand of corrosion. Is that

1 common?

2 MR. CUNANAN: From what I spoke to with John  
3 Wise, he said that if they have -- if they don't have  
4 the right corrosion inhibitor, then you would get  
5 microbiological --

6 MEMBER RYAN: I understand that part. But  
7 is this kind of -- I mean has that been a mismatch in  
8 a lot of places, or is that a fairly rare type of  
9 corrosion?

10 (Simultaneous speaking; laughter.)

11 CHAIR ARMIJO: It's everywhere, Mike.

12 MR. CUNANAN: It's everywhere.

13 MEMBER RYAN: It's everywhere. Thanks,  
14 right.

15 MR. CUNANAN: Next slide. The first open  
16 item addresses how the applicant would consider future  
17 operating experience to inform its aging management  
18 activities. To provide an overview of how this item  
19 was closed, I'd like to introduce Matt Homiack of the  
20 staff. Matt.

21 MR. HOMIACK: Good afternoon. Thank you,  
22 Arthur. As Melanie Galloway highlighted in her  
23 opening remarks, operating experience is important,  
24 because it serves as the feedback mechanism, to ensure  
25 the continued effectiveness of aging management

1 programs.

2 Similar to other plants, programs are  
3 currently being implemented at Columbia to review  
4 operating experience on an ongoing basis, such as  
5 doing the Corrective Action Program.

6 The issue of how the applicant would  
7 consider future operating experience was an open item  
8 for Columbia, because although the applicant indicated  
9 that it would continue to review operating experience,  
10 it did not specifically describe how its existing  
11 programs will address potential issues related to  
12 aging.

13 The staff reviewed several aspects  
14 associated with the applicant's ongoing review of  
15 operating experience, in order to determine whether  
16 this review will provide for the adequate evaluation  
17 of operating experience related to aging.

18 The areas reviewed were consistent with the  
19 guidance in the staff's final license renewal, in  
20 terms of Staff Guidance LR ISG 2011-905, "Ongoing  
21 Review of Operating Experience."

22 As a result, the staff determined that the  
23 applicant's operating experience review activities are  
24 adequate for the capture, identification, processing  
25 and evaluation of both plant-specific and industry

1 operating experience related to aging, and for the  
2 implementation of changes to the aging management  
3 activities, as identified through these evaluations.

4 In addition, the applicant will provide  
5 training on aging to those personnel that screen,  
6 evaluate and submit operating experience, and report  
7 Columbia operating experience on aging to the  
8 industry. This addresses the staff's concern that  
9 future operating experience would not be adequately  
10 incorporated into the aging management programs.

11 MEMBER SKILLMAN: Matt, let me ask this  
12 question. In the homework information that the ACRS  
13 has been provided, there are 35 existing aging  
14 management programs and 20 new programs, 55 programs.  
15 That is a wide swath of administrative activity for  
16 this licensee.

17 The licensee has just communicated about  
18 12,000 CAPs per year, 6,000 will be done within 30  
19 days. That sounds like a pretty good closure rate.

20 In the staff's evaluation of the  
21 effectiveness of this corrective action program, which  
22 is really the workhorse to ensure to this information  
23 is gathered and evaluated and used properly, by chance  
24 did you look at the physical condition of this nuclear  
25 station, to determine whether or not the CAP close-out

1 is effective?

2 For instance, did you look at maintenance  
3 role, the number of AI systems, and the closure rate  
4 of the material condition issues facing the plant, to  
5 develop confidence that the team at Columbia really  
6 gets the job done?

7 MR. HOMIACK: The staff's review with  
8 respect to operating experience was both somewhat of  
9 a process perspective of how operating experience  
10 would be reviewed and translated into the AMPs.

11 As part of the staff's review, we looked at  
12 corrective action entries from the past as part of  
13 every aging management program, in order to determine  
14 how those past issues are going to be addressed.

15 MEMBER SKILLMAN: So you look at it from a  
16 programmatic perspective?

17 MS. GALLOWAY: We have regional  
18 representatives on the phone, and I'm wondering if  
19 they, if either Geoff or Greg would have first-hand  
20 information regarding what's been observed at the  
21 plant?

22 MEMBER SKILLMAN: That would be quite  
23 helpful. Thank you.

24 MS. GALLOWAY: Geoff or Greg? Are the lines  
25 open?

1 DR. HISER: Is the line open?

2 MEMBER SKILLMAN: We probably have it muted.  
3 They're probably screaming at their phones right now,  
4 as we speak.

5 DR. HISER: Well, I guess -- this is Allen  
6 Hiser, License Renewal. The Corrective Action Program  
7 is not unique to license renewal. So this is a  
8 program. It gets a lot of reactor oversight, okay,  
9 from the residents onsite and also regional  
10 inspections.

11 So I think that is really where the  
12 confidence that we have, is that we want to ensure  
13 that the programmatic aspects of the Corrective Action  
14 Program are kept robust for license renewal, in terms  
15 of aging management needs. But in terms of the  
16 overall effectiveness of the program and  
17 implementation aspects of the program, that would be  
18 a part of the current reactor oversight process.

19 MR. MILLER: This is Geoff Miller, Region  
20 IV. Can you hear me?

21 MEMBER SKILLMAN: Yes, yes sir.

22 MR. MILLER: I apologize. I was in fact  
23 screaming at the telephone.

24 (Laughter.)

25 MR. MILLER: The little red light that said



1       mute was off, but apparently it wasn't working. I was  
2       just trying to say that yes, we did do a problem  
3       identification and resolution inspection at Columbia.

4               That was just completed in September of last  
5       year, that did do a look at their Corrective Action  
6       Program and the effectiveness of their current program  
7       resolving problems.

8               The results from that, we did conclude that  
9       the Columbia Generating Station or program was being  
10      implemented effectively, and that they were resolving  
11      those issues, including the use of operating  
12      experience and the closure of items in the CAP. Is  
13      that kind of what you were looking for?

14              MEMBER SKILLMAN: Yes sir, it is. This is  
15      Dick Skillman. Thank you for the answer.

16              MR. MILLER: Sorry about that.

17              MEMBER SKILLMAN: Thank you.

18              MR. HOMIACK: Is there any further  
19      questions?

20              MEMBER SCHULTZ: Just to follow up on that  
21      for a moment. I'm a bit surprised that we would lead  
22      into this with activities that will be implemented  
23      throughout the term of the renewed license, and then  
24      go into assuring that the licensee is going to have a  
25      program of this type.

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1 But the program, as we've just heard, it  
2 does exist now. So I would expect and hope that the  
3 guidance is really indicating the importance of this  
4 for any licensee, whether or not they're going to  
5 renew license, but becomes more important as the plant  
6 moves into a different realm of operation, 40 to 60  
7 years.

8 MS. GALLOWAY: And you're absolutely right,  
9 and you know, I know from the staff's standpoint,  
10 we're glad to hear you say that, because one of the  
11 things we did clarify in the ISG is the fact that you  
12 can't have a situation where you're reviewing  
13 operating experience at the time you're going through  
14 license renewal, and then you don't enter the period  
15 of extended operation for 10, 15, X number of years  
16 later, and you don't do anything.

17 So our ISG makes it clear that there's an  
18 expectation that once you go through the license  
19 renewal process and get a renewed license, that you  
20 are carrying on that program, so that you take  
21 advantage of the operating experience that's gained  
22 from the license renewal time frame, until your period  
23 of extended operation, without missing a beat.

24 It's a continual process, and we think that  
25 is extremely important, in order to be in the best

1 position you can be at the PEO, to manage aging, to  
2 manage the effectiveness of aging.

3 MEMBER SCHULTZ: Thank you, Melanie.

4 MEMBER SIEBER: Actually, the license  
5 renewal application in the accompanying SER is a list  
6 of commitments that licensee make that are bound as  
7 license conditions, and they have to be implemented  
8 before the current license expires, and they are held  
9 accountable by inspections for those actions.

10 One of the reasons why the staff fusses  
11 around to make each of these commitments in sufficient  
12 detail, is to make sure that the aging management  
13 programs and the timing of the aging management  
14 routines meet the regulations.

15 This thought has come up in the past among  
16 Committee members, that this is a beginning step, and  
17 at this point, once a license renewal is issued, it  
18 represents a lot of commitments that the licensee has  
19 to perform, or suffer the penalties of not performing  
20 commitments that the licensee has made, which  
21 ultimately could lead to shutdown of the plant.

22 That's my understanding of what goes on. We  
23 should not expect all these programs to be in place  
24 right now.

25 MS. GALLOWAY: Just one clarification which

1 I think is very important. We at the staff are doing  
2 a lot of look at commitments, and how they are to be  
3 implemented at the time of the period of extended  
4 operation. One thing that we are clear on is that our  
5 expectation is that the commitments will be fulfilled  
6 by the applicant by the time the period of extended  
7 operation starts.

8 However, the content and the substance of  
9 each one of those commitments is not in and of itself  
10 a license condition. So once the applicant enters the  
11 PEO, they do have the ability to alter those  
12 commitments, after having gone through a 5059  
13 evaluation process, because those commitments are  
14 incorporated as part of their FSAR.

15 So we just want to make it clear that  
16 they're not license conditions directly; they're part  
17 of what we require as a license condition, that they  
18 be implemented by the PEO, and then they do have  
19 latitude to change them if undergoing the regulatory  
20 process of 5059.

21 MEMBER SIEBER: The changes made under 5059,  
22 particularly changes that reduce requirements, 5059 is  
23 a lot tougher than it was 30 years ago, and those  
24 should not be lightly made.

25 MR. CUNANAN: Okay. We'll move to the next

1 slide, if there's no further questions. For the high  
2 voltage porcelain insulator program, the applicant has  
3 addressed this issue in their presentation.

4 The applicant included the 230 kilovolt post  
5 insulator as part of their program, with testing every  
6 eight years and cleaning if needed. The staff finds  
7 this acceptable and has closed this item.

8 For the crane load cycle limit, the  
9 applicant already discussed identifying these crane  
10 analyses as TLAAs, and disposition analyses under 10  
11 C.F.R. 54.21(c)(1)(i). The staff has no further  
12 concerns regarding this issue.

13 For metal fatigue, I'd like to introduce  
14 Allen Hiser to present this item.

15 DR. HISER: Thank you, Arthur. With the  
16 increased neutron fluence as a result from plants  
17 going to license renewal, 60 years of operation  
18 instead of 40, for Columbia, the N12 instrumentation  
19 nozzles will achieve a neutron fluence greater than 1  
20 times 10 to the 17th. Therefore, they have to  
21 consider the effects of radiation on the properties of  
22 those nozzles.

23 In response to staff RAIs, the applicant  
24 provided an analysis for those nozzles that included  
25 copper content measurements and also Charpy test data,

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1 including test temperature, absorbed energy and shear  
2 percentage.

3 The applicant, based on that data, cited an  
4 initial upper-shelf energy of 62 foot pounds from its  
5 evaluation of the data, which was sufficient in  
6 combination with the copper content of 0.27 percent,  
7 to project the upper-shelf energy to exceed the  
8 Appendix G of 10 C.F.R. Part 50 required value of 50  
9 foot pounds. So it would meet that criteria.

10 The cooper content was reviewed by the staff  
11 and we found it acceptable, because it was an  
12 appropriately conservative value from the data that  
13 was provided by the applicant. Upon further staff  
14 questioning, the applicant identified that certain of  
15 the Charpy data they provided were actually from the  
16 same heat numbers as the forgings used to fabricate  
17 the N12 nozzles.

18 Segregating that data from the data provided  
19 by the applicant indicated that the upper-shelf energy  
20 and the longitudinal orientation for these heat  
21 numbers is on the order of 230 foot pounds or more,  
22 which crates to an upper shelf energy in the  
23 transverse orientation of something that's  
24 significantly greater than 62 foot pounds, probably on  
25 the order of 150 foot pounds.

1           So based on that analysis and the data  
2           provided by the applicant, the staff found that the  
3           applicant's conservative value of 62 foot pounds to be  
4           acceptable, and the applicant's upper shelf energy  
5           evaluation was found acceptable. Thus, this open item  
6           was closed by the staff.

7           MEMBER SIEBER: I think they were lucky to  
8           find matching samples.

9           DR. HISER: It's always very good to have  
10          data from your own material.

11          MEMBER SIEBER: That's right, and that  
12          doesn't always occur.

13          DR. HISER: No, that's correct.

14          MEMBER SIEBER: It's always kind of rare.

15          MR. CUNANAN: All right. Thank you, Allen.  
16          Environmental-assisted fatigue is a generic item that  
17          the ACRS has seen before with previous plants, such as  
18          Salem and Hope Creek, where contrary to the standard  
19          review plan and GALL report, the applicant had not  
20          considered other plant-specific locations to analyze  
21          for EAF, environmental-assisted fatigue.

22          The staff had asked similar RAIs to those  
23          applicants regarding these concerns. The staff wanted  
24          to know whether the applicant's plan-specific  
25          configurations may have additional locations that need

1 to be analyzed for the effects of EAF, other than  
2 those identified in NUREG-6260.

3 The applicant submitted its results of  
4 addressing EAF to the staff, and the staff conducted  
5 an audit on November 29th through December 1st, 2011,  
6 to verify critical locations that the applicant looked  
7 at. Based on this audit, the staff was able to verify  
8 the applicant's approach in identifying locations that  
9 can be affected by EAF.

10 The staff concluded that the applicant had  
11 appropriately addressed EAF for its plant-specific  
12 configuration. For the core plate rim hold-down  
13 bolts, I'd like to give the presentation back to  
14 Allen, to discuss this item.

15 DR. HISER: As you heard earlier in the  
16 applicant's presentation, when they submitted their  
17 license renewal application, they thought that they  
18 had core plate wedges installed, and so they did not  
19 treat the core plate rim hold-down bolt degradation as  
20 an aging effect requiring management.

21 When they sent a letter to us indicating  
22 that they do not have wedges installed, we had  
23 questions on how they would resolve the TLAA  
24 associated with stress relaxation, and also had  
25 questions about were there, you know, what the aging



1 management review line items are. So what would be  
2 the aging effects that would require management, and  
3 how would they appropriate manage those items.

4 In response to our RAI, the applicant  
5 evaluated the TLAA of stress relaxation, in accordance  
6 with 10 C.F.R. 54.21(c)(1)(iii), and also provided an  
7 AMR line item for stress relaxation of the bolts, that  
8 ties directly to the TLAA.

9 There also is a line item related to  
10 cracking, due to stress corrosion cracking, that was  
11 picked up as well by the applicant. In its response,  
12 the applicant also committed to install the core plate  
13 wedges at least two years prior to the period of  
14 extended operation, which you have heard earlier.

15 The staff has decided that we will issue a  
16 license condition, requiring the applicant to install  
17 these wedges on or before December 20, 2021, which is  
18 two years before their PEO, and this license condition  
19 will also require the applicant to submit a report to  
20 NRC staff, summarizing the results of the installation  
21 of the wedges, and if applicable, any corrective  
22 actions that they implemented.

23 Based on this license condition that will be  
24 put on the license, the renewed license for Columbia,  
25 this item was closed by the staff.

1 MEMBER ABDEL-KHALIK: Does the uncertainty  
2 regarding either the presence or lack of the wedges  
3 point to a bigger problem with regard to configuration  
4 control?

5 DR. HISER: I think that's a very good  
6 question.

7 MEMBER ABDEL-KHALIK: I beg your pardon?

8 DR. HISER: I think that's a very good  
9 question, and I think this is something that we did  
10 discuss with the applicant, in particular with their  
11 internals and the inspections that they did in the May  
12 time frame, provided us with confidence in that area  
13 that there are no other deviations, such as not having  
14 the wedges.

15 MEMBER ABDEL-KHALIK: So you have explicitly  
16 evaluated their configuration controls and determined  
17 that they are adequate, this is just a fluke?

18 DR. HISER: We did not do a systematic  
19 review such as that, no.

20 MEMBER ABDEL-KHALIK: Would that be  
21 appropriate, given the significance of this issue?

22 MS. GALLOWAY: Again, maybe our regional  
23 counterparts on the phone can talk about what  
24 inspections they have done over the last several years  
25 regarding configuration control. Geoff or Greg?

1 MEMBER STETKAR: Don't start yelling yet.  
2 We need to turn you on on this end. It's not your  
3 problem.

4 CHAIR ARMIJO: A little time.

5 (Off record comments.)

6 MEMBER STETKAR: Say something.

7 DR. HISER: Hi Geoff.

8 MR. MILLER: Can you hear me?

9 MEMBER STETKAR: Yes.

10 MR. MILLER: Okay. I was hitting every  
11 button I can think of on this phone.

12 MEMBER STETKAR: No, no. It's this end. We  
13 have you muted here because the system here makes a  
14 lot of noise.

15 MR. MILLER: Oh, okay. I'm sorry about  
16 that. Sorry for the delay. Yes, I did hear the  
17 question, configuration control. It is something that  
18 we look at, as part of our baseline inspections here  
19 in the region. We do have component design basis  
20 inspections that look at configuration control on a  
21 sample basis, and our resident inspectors at the plant  
22 do do, they are involved in continuous reviews of  
23 items that are entered in the CAPs, and they do a  
24 semi-annual review for trends.

25 I'm not aware of them having identified any

1 trends involving configuration control, and I haven't  
2 looked at our most recent CDBI report. But I don't  
3 recall there being an issue with configuration control  
4 identified at the station. There's not a history  
5 there that I'm aware of, that's come up in our  
6 baseline inspections or as part of our assessment  
7 process.

8 MEMBER ABDEL-KHALIK: But given the  
9 significance of this issue, wouldn't this be  
10 something, an item that you should have looked at  
11 explicitly?

12 MR. MILLER: This particular item is  
13 something that would have been identified in the  
14 Corrective Action Program. I can't recall if we  
15 pulled that as a particular sample.

16 MEMBER SKILLMAN: This is Dick Skillman. I  
17 would like to join Dr. Khalik in the question, and for  
18 me, the real issue is extent of condition. Here is a  
19 piece of information that was believed to be accurate,  
20 and it turned out be not correct.

21 Where else in the information that you are  
22 using to justify extended operation, other  
23 vulnerabilities, where an absence of information is  
24 critical? This is an extent of condition question.

25 (Off record comments.)

1 MEMBER SKILLMAN: Maybe another way to ask  
2 the question is in the Corrective Action Program, was  
3 this item closed to fix, or was this item root cause  
4 and develop an extent of condition assessment, please?

5 MS. GALLOWAY: Is that a question the  
6 applicant can answer?

7 MR. RICHTER: Yes. Steve Richter, Energy  
8 Northwest. The issue was closed with actions, and  
9 among those actions was to perform an extent of  
10 condition, first of all to look at the specific  
11 information provided by the OEM, the corrected  
12 information, to make sure there was no other  
13 additional areas of concern there, and then a review  
14 of the vessel internal program, to make sure there  
15 were no other omitted inspections based on presumed,  
16 or presumptions of configuration.

17 MEMBER SKILLMAN: When is that information  
18 to be made available to your staff?

19 MR. RICHTER: Excuse me, what are you  
20 asking?

21 MEMBER SKILLMAN: Is this a six month or 12  
22 month or 24 month or a 36 month bring back? When is  
23 the extent of condition and cause going to be done?

24 MR. RICHTER: Oh, it's completed. I'm  
25 sorry. It's been completed.

1 MEMBER SKILLMAN: And what is your  
2 conclusion?

3 MR. RICHTER: The conclusion was that there  
4 were no other missed inspections. There were no other  
5 impacts, based on the corrected information from the  
6 original equipment manufacturer.

7 MEMBER ABDEL-KHALIK: But that sounds very  
8 narrow, in terms of an evaluation of the extent of  
9 condition. We're looking at the impact on  
10 configuration controls in general.

11 MR. GREGOIRE: In a broader perspective,  
12 there's a number of things. Obviously, the first  
13 thought is what about the vessel?

14 What else in the vessel do we not know? So  
15 again, relying on the BWR VIP guidance with what you  
16 inspect in a vessel, we did go and evaluate internally  
17 what possibly could also be overlooked here, didn't  
18 find anything else there.

19 With regard to configuration management in  
20 the plant, again, we do have regular CDBI inspections  
21 that do assess the health of that process, to  
22 determine if there is anything that we're not managing  
23 appropriately. There have been a few violations in  
24 that area over the years.

25 It is always something of a concern for us

1 to manage that, but in this case here, we did, like I  
2 said, focus our efforts on addressing the vessel  
3 itself and any other possible areas that we might have  
4 overlooked in our inspection process.

5 MEMBER ABDEL-KHALIK: Is the staff satisfied  
6 with this response?

7 DR. HISER: I don't believe we have any  
8 outstanding issues on this.

9 MEMBER ABDEL-KHALIK: Has the staff asked  
10 the question?

11 DR. HISER: I think we relied on the  
12 regional inspection, and again, the regulatory  
13 oversight process on things like this. This is not  
14 specific to a license renewal issue that's addressed  
15 under Part 54. This is part of really ongoing  
16 regulatory oversight.

17 MEMBER ABDEL-KHALIK: But not everything is  
18 a cookie-cutter. I mean if you run into a problem,  
19 you try to sort of nail it down.

20 DR. HISER: Well, and I think as Geoff  
21 mentioned, on the 71002 inspection, that is something  
22 that is considered there. The implications in this  
23 case of not having the wedges, we did follow up on, to  
24 ensure that the license renewal aspects of that would  
25 be appropriately addressed by the applicant.

1 MEMBER ABDEL-KHALIK: Okay, thank you.

2 MR. CUNANAN: All right. That's the last of  
3 the open items.

4 MEMBER SIEBER: The last issue is a current  
5 operating issue, is it not, in terms of closed license  
6 renewal issue?

7 DR. HISER: That's where it's appropriately  
8 addressed, is under the current licensing basis, if  
9 you will, of the plant.

10 MEMBER ABDEL-KHALIK: Has it been?

11 DR. HISER: I would have to defer to the  
12 regionals.

13 MEMBER ABDEL-KHALIK: Root cause provided to  
14 the staff, and determined to be of sufficiently broad  
15 scope to identify the extent of condition?

16 MR. GREGOIRE: Typically, we don't provide  
17 the root cause to the staff for their approval, but we  
18 do certainly make it available to them for their  
19 understanding. We have not received any feedback with  
20 regard to whether we had looked broadly or not. So I  
21 can't say much more than that. This is Don Gregoire.

22 MR. CUNANAN: Are there any further  
23 questions?

24 MEMBER SIEBER: Nope.

25 MR. CUNANAN: Okay, in conclusion, the staff



1 determined that the requirements of 10 C.F.R. 54.29  
2 Alpha have been met for the license renewal of  
3 Columbia Generating Station. This concludes my  
4 presentation. Do you have any further questions?

5 (No response.)

6 MR. CUNANAN: Thank you.

7 CHAIR ARMIJO: Jack, you done?

8 MEMBER ABDEL-KHALIK: Mr. Chairman.

9 MR. ATKINSON: Mr. Chairman?

10 CHAIR ARMIJO: Yes sir.

11 MR. ATKINSON: This is Dale Atkinson with  
12 Energy Northwest. I guess I see the Committee kind of  
13 quibbling with that issue, and I'll offer that the  
14 executives, senior management at Energy Northwest,  
15 were similarly troubled by this.

16 So as a way perhaps to understand it, we did  
17 take a look at why, in this particular case, we have  
18 this situation, where we didn't have what we thought  
19 we had.

20 The short answer is over-reliance on vendor  
21 information in an area that you don't easily get  
22 access to to do inspection. So a lot of the  
23 discussion you've heard is around going back and  
24 looking for that kind of vulnerability.

25 Because in the cases where we have access,

1 where we control for the rest of the configuration,  
2 we've actually done quite well in configuration  
3 management. So I think that's why you're hearing a  
4 lot of this discussion, focusing on where we might  
5 have had an over-dependence on the vendor.

6 In this case, we relied on information from  
7 General Electric that turned out not to be accurate,  
8 and so --

9 CHAIR ARMIJO: They couldn't have been happy  
10 about it either.

11 MR. ATKINSON: No.

12 CHAIR ARMIJO: Did they provide any kind of  
13 explanations that were satisfactory to you, how they  
14 would have made that mistake?

15 MR. ATKINSON: Yeah, I'll offer. I have not  
16 heard anything that was very satisfying. So that's  
17 why we decided let's drop a camera down, take a look,  
18 and then consider any other areas we might be  
19 concerned about. So that's where that went.

20 I'd also like to make one other correction.  
21 I heard the question earlier about the porcelain  
22 insulators. Having been at the plant for 23 years, I  
23 remember a lot of these events.

24 The flashover event that actually caused  
25 this concern with the insulator fouling occurred on

1 500 kilovolt lines. For the purpose of the license  
2 renewal, it's the 230 kilovolt that's in scope.

3 So in fact we did add the inspection to a  
4 230 kilovolt porcelain string out at the Ashe  
5 substation. We verified the adequacy really  
6 previously for a 500 kilovolt line count. All right,  
7 thank you.

8 CHAIR ARMIJO: Okay. Jack, it's okay? All  
9 right. Well, Jack are we completed then?

10 MEMBER SIEBER: It appears that we are, and  
11 if there are no more questions from the Committee, I  
12 turn it back to you, Mr. Chairman.

13 CHAIR ARMIJO: Okay, thank you very much.  
14 I'd like to thank the presenters of the staff and the  
15 applicant. Very good presentations. What we'll do  
16 now is we'll take a break and reconvene at 2:30.

17 (Whereupon, a short recess was taken.)

18 CHAIR ARMIJO: Okay. Let's come back to  
19 order. The next topic is the risk-informed regulatory  
20 framework for new reactors. John will lead us through  
21 this presentation.

22 MEMBER STETKAR: Thank you, Mr. Chairman.  
23 Some background for the other Committee members.  
24 We've had a couple of Subcommittee meetings on this  
25 topic last year and in March of this year. The staff,

1 I'm sure, will fill us in on some of the details.  
2 They're sending a SECY paper up to the Commission I  
3 believe in -- it's scheduled to go up in June, early  
4 June.

5 CHAIR ARMIJO: Early.

6 MEMBER STETKAR: And as a background,  
7 they've been running for almost the better part of a  
8 year, I guess, right, on a number of tabletop  
9 exercises and public workshops, where the goal was to  
10 look at a range of possible risk-informed applications  
11 for new reactors, evaluating them in the context of  
12 existing regulatory guidance, to see how the current  
13 regulatory guidance and current metrics that are  
14 applied as a result of that guidance, what sort of  
15 conclusions you can draw in terms of applicability of  
16 the guidance. Is there a need for updates to the  
17 guidance, and as a result of those exercises, the  
18 staff has developed some options that they're going to  
19 send up to the Commission going forward.

20 So we'd be writing the letter on the SECY  
21 paper that the staff will, I believe, present some of  
22 the results of the table top exercises and a couple of  
23 the more interesting applications, and then go through  
24 the SECY paper.

25 With that, I'll turn it over to the staff,

1 and I think Charlie Ader would probably like to say  
2 something.

3 MR. ADER: I'd just say I'd welcome the  
4 opportunity again to discuss this with the ACRS.  
5 We've had a number of interactions over the last  
6 couple of years. They've all been, you know, very  
7 beneficial interactions. The staff has done a lot of  
8 work. We've had excellent cooperation with  
9 stakeholders too in developing this paper.

10 So I think we're coming, hopefully coming to  
11 the end of this process here pretty soon. I'll turn  
12 it over to Don.

13 MR. DUBE: Thanks Charlie. Thanks, Mr.  
14 Chairman and John and members. I want to acknowledge  
15 Ron Fruhm from NRR, who's handled the reactor  
16 oversight process end of things, and also a couple of  
17 people who aren't here.

18 Eric Powell, who works with me, he's on  
19 rotation; and Chris Hunter did a lot of the  
20 calculations. He's out of Research, Office of Nuclear  
21 Regulatory Research, and he did many, many of the  
22 calculations for the reactor oversight process.

23 So I just want to acknowledge them, and as  
24 Charlie said, we had excellent participation by  
25 industry and other stakeholders. So we're here to

1 discuss the staff's response to the staff requirements  
2 memorandum, in response to the Commission paper 10-  
3 121, and to request a letter.

4 On the agenda this afternoon, we'll give  
5 very brief background. It will emphasize two table  
6 top exercises, Risk-Informed Tech Spec Initiative 4b,  
7 which is on completion times, and then Ron will talk  
8 about the reactor oversight process.

9 We'll touch upon the other table top results  
10 and some of the recommendations, our next vessel  
11 severe accident Tier 2 change process, and this long-  
12 standing issue of converting from large early release  
13 frequency to large early release frequency. But the  
14 emphasis will be on RITS 4b and ROP.

15 Then conclusions, options and  
16 recommendations in the draft paper, and highlight a  
17 couple of small, in the way of editorial changes, that  
18 we've made to the paper, just very briefly.

19 So as a reminder, way back over a year ago,  
20 a year and a half ago now, where the staff presented  
21 the Commission with three options to address the risk-  
22 informed guidance for new reactors, and it was in  
23 light of the fact that new reactors have quite a bit  
24 different risk profile than the current fleet.

25 Generally, significantly, one to three

1 orders of magnitude lower calculated core damage  
2 frequency, at least for internal events. Probably not  
3 so much when one takes into account external events  
4 like seismic, for example. But still, as a general  
5 rule, somewhat lower, in some cases significantly  
6 lower than the current fleet, and what does one do  
7 with that observation.

8 In fact, does one still apply the same risk  
9 metrics, the same thresholds in the reactor oversight  
10 process, or should there be new and different  
11 thresholds? So the staff presented the Commission  
12 with three options. One was basically status quo,  
13 we'll treat them the same as the current fleet.

14 Second -- well, I'll talk about the third.  
15 The third was actually develop lower numeric  
16 thresholds for the new reactors, and option 2 was kind  
17 of in between, which says well, let's look at the  
18 guidance and maybe there's some tweaking we can do,  
19 but we won't actually change the thresholds.

20 The Commission came back in an SRM dated  
21 March 2nd of last year. They approved a hybrid of  
22 Options 1 and 2, which was continue the existing risk-  
23 informed framework, but do a series of table top  
24 exercises.

25 They actually spelled out four or five

1 specific areas for us to table top, and we table  
2 topped all of those areas, and then a couple of other  
3 risk-informed application areas.

4 But very profoundly, the Commission  
5 reaffirmed the existing safety goals, safety  
6 performance expectations, subsidiary risk goals in the  
7 risk guidance, and the key principles that are in, for  
8 example, Reg Guide 1.174, and these are principles  
9 such as small change would result in a small increase  
10 in core damage frequency, and risk, maintain defense  
11 indepth, maintain margin of safety and monitor the  
12 performance over the existence of that risk-informed  
13 application.

14 They also reaffirmed the quantitative  
15 metrics, and they stated that, I'm paraphrasing here,  
16 new reactors with enhanced margins and safety features  
17 should have greater operational flexibility than  
18 current reactors.

19 So that kind of set the boundary conditions  
20 for what the staff would look at. We couldn't go so  
21 far as proposing lower numeric thresholds, so we need  
22 it to work within the directive from NSSRM.

23 So we did a very aggressive series of table  
24 top exercises. We actually started out before the  
25 SRM, because we knew we had to look at the change



1 process for severe accident design features.

2 These are spelled out in VIII(b)(5)(C) of  
3 each design certification rule, and it states if  
4 there's a substantial increase in probability or  
5 public consequences associated with a change, a Tier  
6 2 change to a severe accident feature, that there's a  
7 number of steps that the applicant or license holder  
8 has to go through.

9 So we did that. We started out with that  
10 first, and then a series of very busy and very  
11 aggressive table top. Risk-informed in-service  
12 inspection of piping, Risk-Informed Tech Specs  
13 Initiative 4b on completion times, and affiliated with  
14 that is the Maintenance Rule (a)(4), which is  
15 monitoring and managing risk during equipment outages  
16 and maintenance.

17 We did the other half of Risk-Informed  
18 Tech Spec initiative, kind of a little bit of twin  
19 5(b) on surveillance frequency control program. We  
20 looked at 5069, which is categorization of structure  
21 systems and components, and special treatment thereof.

22 We looked at guidance in aiding NEI-9607  
23 Appendix C. This is one-stop shopping for all the  
24 change processes for new reactors. So it's not just  
25 -- it's a 5059-like process, severe accident features.

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1 Everything from aircraft impact assessments  
2 and large area fires. Everything is a go-to one-stop  
3 shopping, and it may have the licensee go out in  
4 different directions, but basically it is a one-stop  
5 shopping, if you will. We looked specifically at the  
6 change process for ex-vessel severe accident features.

7 Then we jumped into Reg Guide 1.174, which  
8 is risk-informed changes to the licensing basis. We  
9 wanted to tackle this long-standing issue of large  
10 early release frequency and I'll briefly touch upon  
11 that, and then we did a large number of table top  
12 exercises on the reactor oversight process.

13 This includes the significance determination  
14 process, reactive inspections under Management  
15 Directive 8.3 and the mitigating systems performance  
16 index, and then we had a follow-up meeting.

17 So I mean it was very extensive, and we were  
18 basically finishing up one table top, summarizing the  
19 results and preparing for the next table top just a  
20 few weeks later, in a couple of cases.

21 So what is a table top exercise? Basically  
22 what it is is we looked an outline of the guidance,  
23 especially the risk aspects of the guidance, and we  
24 said -- we had representatives from industry and our  
25 own staff and said what's been the experience with the

1 current fleet? What's been -- as a result of proposed  
2 applications, what was the level of risk increase?

3 Some of it was a little theoretical, but  
4 what's been the experience? Has it been good, bad,  
5 indifferent? Has it been risk-neutral, and what might  
6 this guidance look like if we applied it to a new  
7 reactor?

8 So we actually looked at, depending on the  
9 particular exercise, one to five of the new reactor  
10 types. I mean in the case of Risk-Informed Tech Spec  
11 Initiative 4b on completion time, we had all five  
12 reactor design centers there. The new reactor design  
13 centers with combined license applications all  
14 participated in doing calculations.

15 In other cases, we had less data to work  
16 from. But we did apply it and said what would it look  
17 like for new reactor, what are the lessons learned and  
18 is there any concerns here, in terms of could there  
19 possibly be a significant decrease in the enhanced  
20 level of safety of the new reactor as a result?

21 So in many cases, we actually did many, many  
22 calculations. In some cases, it was looking more at  
23 a lot of situations. So getting to the major  
24 conclusions right off the top, during the table top  
25 exercises for the licensing application, so that's

1 Risk-Informed Tech Spec 4b, 5(b), a risk-informed in-  
2 service inspection, those were where a license  
3 amendment would be needed.

4 Staff did not identify any potentially  
5 significant decrease in the enhanced safety margins  
6 for new reactors. Now a little bit of this is, like  
7 I said, is inductive reasoning, inductive reasoning in  
8 the sense of we did many, many calculations, many,  
9 many applications, well over 100, and we tried to  
10 generalize, you know, what can one generalize from  
11 these regarding the overall guidance?

12 So like I said, in that regards, it is a bit  
13 of inductive reasoning, but it's the best one can do.  
14 We did identify a potential gap in the Tier 2 change  
15 process regarding severe accident features that are  
16 not related to ex-vessel severe accident prevention  
17 and mitigation.

18 I have my Venn diagram from the Subcommittee  
19 meeting, which I'll show. But the staff did identify  
20 a gap. We don't think it's a significant gap, but  
21 it's probably something that should get addressed by  
22 the NRC.

23 Current risk thresholds are appropriate for  
24 the reactor oversight process. Ron will talk about  
25 this, but there's a few changes that could be made,

1 particularly that might be warranted, consistent with  
2 the integrated risk-informed principles in Reg Guide  
3 1.174.

4 A lot of this has to do with barrier  
5 integrity, and if one goes through a calculation and  
6 calculates if there's a degradation of a barrier such  
7 as reactor coolant system barrier, and one relies on  
8 the calculations, such as conditional core damage  
9 probability, one inevitably gets low numbers.

10 And yet, you know, relying on margin of  
11 safety and defense indepth, does one feel comfortable  
12 with the regulatory response, just based on, solely on  
13 the risk calculations. So we believe there's areas  
14 here that will change, or some change will probably be  
15 needed, especially for the new reactors, but some of  
16 it might be applicable to the current fleet as well.  
17 There's always some improvement in guidance that could  
18 be found.

19 So that's the background of where we are,  
20 and over the next couple of slides, I'm going to talk  
21 about one specific exercise, but probably the most  
22 intriguing exercise, and that is on Risk-Informed Tech  
23 Spec 4b completion times. We found time and time  
24 again on this that built into the guidance, into the  
25 overall program, are two key programmatic controls,

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1 that the risk-informed completion time is limited to  
2 a deterministic maximum of 30 days, referred to as the  
3 backstop completion time, from the time the tech spec  
4 action statement was first entered.

5 So the risk-informed completion time is kind  
6 of like an online monitoring of risk. Equipment is  
7 either found to be in a failed condition, degraded  
8 condition, or voluntary entry to take maintenance  
9 action on a particular piece of equipment and monitor  
10 to the performance.

11 There's a guidance where one calculates how  
12 long can the plant remain in that configuration,  
13 maintenance configuration, and still meet certain  
14 quantitative metrics, and sometimes it might be a  
15 value calculated by the PRA to be days, tens of days,  
16 hundreds of days, I'll show you a case, thousands of  
17 days.

18 But the backstop says notwithstanding that  
19 calculation, there will be no more than 30 days would  
20 be allowed. Then a second programmatic control is  
21 voluntary use of the risk-managed tech spec for  
22 configuration, which represents a loss of tech spec  
23 safety function or inoperability of all required  
24 trains would not be permitted.

25 So we may have a boiling water reactor that

1 has, let's say, three trains of high pressure  
2 injection and three trains of lower pressure  
3 injection. A situation where all three trains of high  
4 pressure injection would not be allowed. You always  
5 have to have some degree of defense indepth.

6 Even though the plant could depressurize,  
7 open the pressurization valves and use low pressure  
8 injections, one would always have to make some kind of  
9 tech-spec specified safety function, and not allow it  
10 to go bad, even if the risk numbers were say  
11 theoretically permissible.

12 MEMBER BROWN: Before you change the page --

13 MR. DUBE: Sure.

14 MEMBER BROWN: Risk-informed completion  
15 time. Is there -- it's going to be applied, so  
16 theoretically this would be utilized throughout the  
17 fleet; correct, or is that --

18 MR. DUBE: No. They would have to come in  
19 with a license amendment, an applicant --

20 MEMBER BROWN: Okay. They'd have to change  
21 their existing basis, if they wanted to go this way?

22 MR. DUBE: Yes, right.

23 MEMBER BROWN: All right now, thank you. I  
24 messed that part up.

25 MR. DUBE: There is one design center COL

1 applicant, this would be the Mitsubishi USAPWR and the  
2 applicant, COL applicant is Luminant for Comanche Peak  
3 3 and 4, where right from the start they want to  
4 implement.

5 MEMBER BROWN: Okay. Now let me get on with  
6 my -- if you have multiple people, who develops the  
7 algorithm or the risk-informed methodology for each?  
8 Are these dictated by the NRC?

9 MR. DUBE: The methodology is in a guidance  
10 that the staff's endorsed, and the numerical values  
11 are in the guidance. But the license holder has PRA-2  
12 that has to meet requirements for technical adequacy,  
13 and has procedures, station procedures for  
14 implementing.

15 MEMBER BROWN: Okay. So if you had one  
16 particular plant design that was replicated, I'm  
17 assuming they all implemented this risk-informed via  
18 some license amendment?

19 MR. DUBE: Exactly.

20 MEMBER BROWN: And say you had eight plant  
21 sites that had all said we're going to go do it this  
22 way, and they're all identical plants. But they all  
23 have their own PRA and therefore they could all come  
24 up for the same down or degraded condition? They  
25 could come up with different completion times?



1           For just a backstop, let's assume they all  
2           came up with something less than 30 days. One of them  
3           could say well gee, I'm only going to operate for five  
4           days based on my analysis, and the other one will say  
5           well my methodology says ten; somebody else's says  
6           eight; somebody else's says 15.

7           MR. DUBE: We wouldn't expect that.

8           MEMBER BROWN: Well, I know I wouldn't  
9           expect it, but I'm just saying if you don't have a  
10          consistent --

11          MR. DUBE: Every situation is unique, and so  
12          AP1000, you have a Shearon Harris, you have -- I mean  
13          no, Summer and Vogtle.

14          MEMBER BROWN: Vogtle, right.

15          MR. DUBE: And their PRAs are mostly very  
16          similar. In fact, it's probably at this point  
17          maintained by Westinghouse. Since it's very similar  
18          to the same equipment outage, those different unit  
19          sites for the same amount of time should be very  
20          comparably the same value.

21          MEMBER BROWN: Well, what do you mean by --  
22          but why shouldn't they be the same?

23          MR. DUBE: Well, you may have external  
24          events, so you have some -- you have to take into  
25          account external events. So you have the seismic risk

1 at one site may be different than at another site. So  
2 there could be some differences there. The internal  
3 event, you have power, fire, internal flooding, based  
4 on the current standard design, should be identical.

5 But there will be some site-specific  
6 differences in the risk assessment. External flood,  
7 tornado, seismic. So when they go through the number,  
8 if Plan A has high pressure injection train A out for,  
9 in this case it would be a little bit different for  
10 AP1000, but one train out for so many days.

11 They may have a certain number, and it might  
12 be different from the other site because of the  
13 contribution from external events may be different.  
14 That's why I say it should be somewhat similar. Does  
15 that make sense?

16 MEMBER BROWN: Not -- I understand what you  
17 said, but it doesn't make sense to me that I've got  
18 identical trains, identical whatever in terms of the  
19 plant design in AP1000. I would expect that one or  
20 two, I think division or a channel or a train,  
21 whatever it is, is out of service. I would expect I'd  
22 have limited operating --

23 Inelegant is the specification of a time for  
24 each one. You'd get consistency to plants. Now I've  
25 got inconsistency from plant to plant, based on the

1 theoretical thought process, that gee, my risk from  
2 all these other things, whether it be tornadoes or  
3 seismic or tsunamis or flooding or what have you,  
4 gives me more or less external effect.

5 Therefore, I can let this thing stay out for  
6 20 days instead of five --

7 (Simultaneous speaking.)

8 MEMBER BROWN: I'm saying, I said that for,  
9 just to make the point clear. That was the only  
10 reason I said that.

11 MEMBER STETKAR: Yes.

12 MEMBER BROWN: So that's just -- personally,  
13 I understand. You all love this stuff. I just don't.

14 MEMBER STETKAR: Charlie, if you built your  
15 plant on top of a volcano compared to another plant,  
16 there would be a difference.

17 MEMBER BROWN: Well, if I had trains out,  
18 I'd --

19 MEMBER STETKAR: Charlie, if you only think  
20 about internal events, that's true. If you think  
21 about the entire spectrum of contributors to risk,  
22 it's different. You must consider -- if Fukushima had  
23 been built in the middle of the island of whatever.

24 MEMBER BROWN: Krakatoa.

25 MEMBER STETKAR: You know, we wouldn't be

1       having the discussions we're having these days. You  
2       do need to consider those external events, and they  
3       do, they can make a difference. In most cases, not  
4       very much, but --

5               MR. DUBE: The methodology is consistent.  
6       The tools are consistent, but the plant-specific  
7       unique risk profile can result in slight differences,  
8       and I don't think it would be 20 and 5 days; it would  
9       be 20 and 19.

10              MEMBER BROWN: No. Only to, that was not  
11       meant to be characteristic. I understand that point.

12              MEMBER STETKAR: And for new plants, they  
13       are required to look at the whole spectrum of, to a  
14       greater or lesser extent, full spectrum of internal  
15       and external events, in all operating modes.

16              MR. DUBE: Well yeah. I mean that -- for  
17       new reactors, at the time of initial fuel load, they  
18       have to have a PRA that addresses NRC-endorsed  
19       standards one year before, and NRC's endorsed internal  
20       events, fire, external events, seismic, and all other  
21       external events.

22              So when the plant, the first plant starts  
23       up, it's going to have a full PRA covering --

24              MEMBER STETKAR: For full power anyway.

25              MR. DUBE: For full power, and probably

1 lower power shutdown. So yeah, I understand your  
2 point. I mean but there's consistency in methodology  
3 and guidance and approach, pretty much consistency in  
4 the pool that's being used, and if there is a  
5 difference, it's because of site differences.

6 MEMBER STETKAR: Well, of course going  
7 forward, there can be operational experience  
8 differences.

9 MR. DUBE: Over time, yes.

10 MEMBER STETKAR: That over time could cause  
11 some deviation from plant to plant.

12 MEMBER. SHACK: You might even have  
13 procedural differences.

14 MEMBER STETKAR: You might even have  
15 procedural differences.

16 MEMBER. SHACK: People just do things  
17 differently.

18 MR. DUBE: So continuing on this, we did a  
19 series of calculations. All together on Risk-Informed  
20 Tech Spec Initiative 4b, we did about 100  
21 calculations. That was done by the staff and industry  
22 participants, and we had -- one way or another, we  
23 addressed the advanced boiling water reactor, the  
24 advanced pressurized water reactor, the ESBWR, AP1000  
25 and EPR, U.S. EPR.

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1           We, staff used a standardized plant analysis  
2 risk model, and we just used the internal events. But  
3 we're trying to see, you know, what does it tell us?  
4 Some of the other design centers had some  
5 representation of other events, but I'll go over the  
6 AP1000, some of the examples and calculations.

7           So we simulated the removal from service or  
8 inoperability by choosing, in PRA terms, a basic event  
9 in a PRA model and setting it to true, and for some of  
10 these, subsystems and components like here I'm showing  
11 check valves that really don't do online maintenance  
12 per se, and it wouldn't make sense. It's a passive  
13 system. You're not going to go inside containment and  
14 start working on a check valve.

15           But we chose the basic event there so we  
16 could represent a subsystem or train or a pathway  
17 being declared inoperable. So that was just a  
18 convenient tool. The AP1000 has four Class 1E DC  
19 systems, A, B, C, D, 24 hour battery on A and D, and  
20 24 hour and 72 hours on B and C. So you're already  
21 starting with a bit of a asymmetry there.

22           We looked at all various combinations of DC  
23 power outages, and also passive cooling system train  
24 and subtrain outages, everything from accumulators to  
25 core make-up tanks, to the drain line from the in

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1 containment refueling water storage tanks.

2 MEMBER STETKAR: Don, before you get into  
3 some more details, for the benefit of the Committee  
4 members who haven't attended the Subcommittee  
5 meetings, and I've honestly forgotten also, on the  
6 RITS 4b, were all of those done through the SPAR  
7 models, or did some of the design centers use --

8 MR. DUBE: AP1000 participators sat in a  
9 meeting. While they did not numerically present  
10 results that confirmed all of our findings and say  
11 yeah, that's true, that's correct. That's the kind of  
12 value that we see.

13 MEMBER STETKAR: But RITS 4b was actually  
14 run only on the SPAR models?

15 MR. DUBE: For AP1000, yes.

16 MEMBER STETKAR: For AP1000, okay.

17 MR. DUBE: ESBWR was just GE Hitachi did the  
18 calcs. APWR was Mitsubishi. EPR was AREVA, and ABWR,  
19 staff did the calculations using the SPAR model.

20 MEMBER STETKAR: But the other three, ESBWR,  
21 EPR and ESBWR did their calcs with their own PRA  
22 models?

23 MR. DUBE: Yes, that's right.

24 MEMBER STETKAR: Okay. It's kind of an  
25 important perspective for the Committee to understand,

1       you know, these aren't necessarily all SPAR model  
2       calculations.

3               MR. DUBE:  Yeah, correct, and when we, you  
4       know, these are two full day meetings.  Two full days  
5       of workshops.

6               MEMBER CORRADINI:  But the point being,  
7       John, I just want to make sure I understand.  Your  
8       point being that there's kind of a double check --

9               MR. DUBE:  Well, there's some limitations of  
10      SPAR models.

11              (Simultaneous speaking.)

12              MEMBER STETKAR:  Yeah, I mean you know, if  
13      there's some limitations of SPAR models, and one  
14      always has a bit of concern about are those  
15      limitations driving any of the results.  If you have  
16      various participants using their own models, you get  
17      a little bit better confidence in consistency.

18              MR. DUBE:  Right, yeah.  So for the first  
19      day of the table top, it was mostly staff results, and  
20      then once the industry got an idea of how we did  
21      calculations, then the second workshop, which was  
22      about a week later, they came in with their  
23      calculations, and they were pretty extensive.

24              So here is three out of a couple of dozen  
25      cases that were ran for the AP1000.  There's a lot of



1 information here, but I'll walk you through. I'm only  
2 showing base case and three cases. So if I can take  
3 the time to walk you through.

4 So these were three cases, as I mentioned,  
5 out of the order of 100 that we did for all the  
6 reactor design centers. So on the top line, showing  
7 the case, the equipment that's not functional, that we  
8 assumed was either in a failed state or was out of  
9 service for maintenance, the core damage frequency,  
10 the change of core damage frequency from the base, the  
11 calculated completion time, what the tech spec limit  
12 would be, what the allowed completion time would be,  
13 based on the RITS 4b and what the incremental core  
14 damage probability would be, and what the other  
15 available equipment is.

16 That's important, because you have to  
17 maintain some defense indepth and some safety function  
18 for the various configurations, or else one has to  
19 basically immediately start a shutdown. So the base  
20 case, the SPAR model core damage frequency, with no  
21 testing and maintenance of any equipment, so  
22 everything's available, core damage frequency at that  
23 point in time is an annual rate of 2 times 10 to the  
24 minus 7. That's just internal events at power.

25 So that's the base, what we call the base

1 value. So then in Case 1, the next line, we started  
2 simple, one thing at a time, and then we really built  
3 up later on, to two pieces of equipment, three pieces  
4 of equipment, four, five, six pieces of equipment,  
5 really stretching it.

6 But here, we just kept it simple. We took  
7 out the A Class 1E DC power supply. In other words,  
8 called it operable and at maintenance state. So the  
9 core damage frequency would go from 2.1 E to the minus  
10 7, to 5.9 E minus 7. You'll see the delta CDF the  
11 next column over. You see the 3.8 E to the minus 7.

12 So that's the delta. That's the change, and  
13 we started at a baseline 2.1 and went up to 5.9. So  
14 that delta's 3.8 E minus 7. Now by the guidance, the  
15 incremental core damage probability is allowed to go  
16 up to 10 to the minus 5, and t hat's a straight  
17 probability. It's an integral of the change in core  
18 damage frequency over time.

19 So per year times year is a unit-less  
20 number. It's a probability. That, by the guidance,  
21 would be allowed to go up to 10 to the minus 5. So if  
22 you --

23 MEMBER CORRADINI: 10 to the minus 5, it  
24 would be allowed to go up before what?

25 MR. DUBE: Before they have to take

1 corrective action and begin, either restore it or shut  
2 down.

3 MEMBER CORRADINI: Okay. What's the next  
4 column? Maybe you said it, but calculation completion  
5 time.

6 MR. DUBE: I'm going to talk about it right  
7 now. So if you take that eight, the change in core  
8 damage frequency, 3.8 E times 10 to the minus 7, by  
9 how many years can I multiply that to get 10 to the  
10 minus 5, using days, some incredible number, like  
11 9,623 days?

12 Well, remember I said by the backstop, can't  
13 go more than 30 days, so and the tech spec limit is  
14 only six hours.

15 MEMBER BROWN: The existing tech spec by the  
16 DCD?

17 MR. DUBE: Right, the standard tech spec.  
18 So that's a pretty extreme case, but the tech spec  
19 would only allow the configuration six hours. The  
20 risk would allow 9,000 days, but by the backstop, they  
21 would only be allowed to be in this configuration for  
22 30 days.

23 If you take the change in core damage  
24 frequency, 3.8 times 10 to the minus 7 times 30 days,  
25 converted to years. So the actual incremental core

1 damage probability for this change in risk, integrated  
2 over 30 days, would be 3 times 10 to the minus 8.

3 So that's substantially lower than, you  
4 know, 10 to the minus 5 by the guidance. So what's  
5 the -- and by the way, the other available equipment  
6 they have, one 24 hour division remaining, and two 24  
7 by 72 hour divisions remaining. So they still have  
8 three divisions of DC power available.

9 So what's the message from this is that tech  
10 spec limits are very stringent, and we found that on  
11 the AP1000 ESBWR. So in risk space, they're very,  
12 very stringent. If you want to rely just on a risk  
13 number, it would be 9,000 days. But you know, by the  
14 guidance, they would be restricted to 30 days.

15 So this is providing operational  
16 flexibility, right? Going from six hours to 30 days  
17 provides operational flexibility, but the risk  
18 calculation is still low. 3 times 10 to the minus 8  
19 is a very low change in core damage probability. Any  
20 questions on that one line, that first line?

21 MEMBER CORRADINI: John, can I ask about the  
22 next two lines?

23 MR. DUBE: Well, the next two lines are what  
24 if we took -- what if the licensee was in a situation  
25 where for whatever reason, one drain line, injection

1 line from the in-containment refueling water storage  
2 tank, I'll call that line B, were out? So there's two  
3 passive train lines, and they come into a direct  
4 vessel injection path that goes into the reactor  
5 vessel.

6 Well, that would -- in that instant it's  
7 inoperable or not functional, core damage frequency  
8 would be 1.1 E to the minus 4. The delta would round  
9 off. It's still 1.1 E to the minus 4. The calculated  
10 completion time would be 33 days. Tech spec limits  
11 are very stringent, one hour. In other words,  
12 shutdown right away.

13 Would it be allowed to go 33 days, because  
14 that's what the calculation says? Well, the answer is  
15 no, because in design basis space, you have two drain  
16 lines feeding into the vessel injection.

17 If the D line is inoperable and there was a  
18 pipe break on the A line, the core makeup tank and  
19 drainage from the IRWST on the A line and the  
20 accumulator, we assume to go out that break, and it  
21 could not mitigate a design basis accident, the design  
22 basis accident being, you know, failure of this  
23 passive system and break on the other division.

24 So even though theoretically they could  
25 operate and meet the incremental core damage

1 probability of 10 to the minus 5 for up to 33 days,  
2 this configuration would not be allowed, and it would  
3 require --

4 MEMBER CORRADINI: Why wouldn't it? That's  
5 what I didn't catch. I figured by putting one hour in  
6 parens, you weren't going to use 33 days, and why?

7 MR. DUBE: Because --

8 MEMBER BROWN: So the methodology doesn't  
9 work.

10 MR. DUBE: No.

11 MEMBER BROWN: You can't get a 30 days.

12 MEMBER SIEBER: It's margin.

13 MR. DUBE: No, it's restricted. The risk  
14 calculation is necessary but not sufficient. One  
15 still has to demonstrate that the risk increase is  
16 small, and that defense indepth is maintained. In  
17 this configuration, there is no defense indepth.

18 MEMBER CORRADINI: Meaning there's no  
19 redundant system. You lose one, you're toast.

20 MR. DUBE: Exactly. If the LOCA were to  
21 occur in the direct vessel injection line, based on a  
22 design basis question.

23 MEMBER CORRADINI: Yeah.

24 MR. DUBE: But even PRA, you have --

25 (Simultaneous speaking.)

1 MR. DUBE: --say that that's core damage.

2 MEMBER CORRADINI: I don't know. You guys  
3 are kind of way out there. That was just for John.

4 MR. DUBE: See, certainly voluntary use is  
5 not allowed, or inoperability of all required safety  
6 training is not permitted. So in this case, there is  
7 no redundancy. So you cannot meet the tech spec  
8 safety function.

9 MEMBER CORRADINI: So but the reason you're  
10 -- I guess I'm kind of with Charlie. The reason that  
11 one hour works, one hour needs to be used here is not  
12 because of your backstop; it's because from a design  
13 basis standpoint, you have no redundancy?

14 MR. DUBE: Exactly.

15 MEMBER STETKAR: I mean in principle in this  
16 case, whoever wrote the tech specs essentially gave  
17 them an hour to try to fix the problem.

18 MR. DUBE: You're not going to fix it in an  
19 hour.

20 MEMBER STETKAR: In principle, it's a  
21 disallowed --

22 MR. DUBE: An hour is -- having been in an  
23 operating company, an hour is enough time to call the  
24 dispatcher and say "I'm shutting down." Especially  
25 since these are passive systems inside

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1       containment.

2               MEMBER BROWN:   So the point being, you have  
3       to    have    a    backstop    methodology    engineering  
4       deterministic thought process, in order to come up  
5       with the right answer?  I thought of that one, just to  
6       be aggravating.

7               MR. DUBE:   Yeah, yeah.  The real answer is  
8       a small increase, risk increase is necessary but not  
9       sufficient.  Remember the principles of Reg Guide  
10      1.174 and risk-informed regulation.  One has to have  
11      a small risk increase and demonstrate defense indepth,  
12      and demonstrate margin of safety and monitor  
13      performance.

14              MEMBER BROWN:  The incremental core damage  
15      probability increases only --

16              (Simultaneous speaking.)

17              MEMBER BROWN:  One point is smaller than the  
18      other one.

19              MR. DUBE:   Right.  So the risk increase is  
20      small.  That meets the necessary condition, but it's  
21      not sufficient.  There is not enough -- there is no  
22      defense indepth against a certain accident.

23              MEMBER CORRADINI:  So can I say, if only on  
24      this example, because you'll tell me the example is  
25      too isolated for this, is that the two examples you

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1 gave are one, I had multiple redundancies, and the  
2 other I had only a single redundancy?

3 MR. DUBE: Right.

4 MEMBER CORRADINI: That's the essence of why  
5 one is big and the other is small?

6 MR. DUBE: What's big, the allowed  
7 completion time?

8 MEMBER CORRADINI: Yeah.

9 MR. DUBE: Yeah.

10 MEMBER BROWN: So the risk-informed  
11 methodology can't be applied to those things with one  
12 redundancy?

13 MR. DUBE: Yeah.

14 MEMBER BROWN: So you don't want anybody to  
15 think about it. You just want them to go do it.

16 MR. DUBE: But for most of the reactors, now  
17 this is an extreme case that I'm presenting. It's an  
18 interesting case, Case 7 here. But for most of the  
19 plants, their three trains or four being redundant.  
20 So ABWR typically has three trains of high pressure  
21 injection, low pressure injection.

22 The EPR, APWR has four trains. The APWR  
23 they have 50 percent trains, but still four trains.  
24 ESBWR has multiple trains, many systems.

25 MEMBER CORRADINI: But let's try the problem

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1 backwards. What if there were three lines for the  
2 IRWST. You would probably come up with an allowable  
3 30 day fix on it?

4 MR. DUBE: Possibly, yeah, yep.

5 MEMBER CORRADINI: So it's going from four  
6 to two that made the big difference? That what I  
7 guess I'm trying to do. I'm trying to --

8 (Simultaneous speaking.)

9 MEMBER STETKAR: Yeah. I mean in that case,  
10 in that case it would be like the Example No. 1.  
11 You'd back up to the 30 days if you do that.

12 MR. DUBE: Yes. It would be backed up.

13 MEMBER CORRADINI: Okay, that's fine.

14 MEMBER ABDEL-KHALIK: But the two key  
15 programmatic controls that you're talking about, the  
16 second one talks about loss of tech specs specified  
17 safety function, not loss of redundancy in tech-spec  
18 safety function.

19 MR. DUBE: Now there's a whole -- we have  
20 some tech spec people, experts in the audience.  
21 There's a whole section in the tech specs that  
22 provides guidance on loss of safety function.

23 MR. BRADLEY: It's 303 in the existing  
24 specs. I assume that's the same --

25 MEMBER STETKAR: Biff, you have to identify

1       yourself.

2                   MR. BRADLEY: I'm sorry. Biff Bradley, NEI.  
3       Tech Spec 303, LCO 303 precludes entering a condition  
4       of loss of function. It pus that one hour completion  
5       time for a loss of function, and that's not affected  
6       by this initiative.

7                   MEMBER BROWN: So you have to have a process  
8       that people don't use the risk-informed methodology  
9       where it can't be applied?

10                  MR. BRADLEY: It's right there in the tech  
11       specs.

12                  MR. DUBE: Yeah. This is in the tech specs.

13                  MR. BRADLEY: Yeah.

14                  MEMBER BROWN: Yeah, I know. But I didn't  
15       read like Said over here. I read that and I said oh,  
16       voluntary use of a risk-informed tech spec for  
17       configuration, which represents a loss of safety under  
18       the design condition, I presume. If you've got one  
19       out of service you could have the other one fail, and  
20       therefore you're not permitted to use the methodology.  
21       But that, I didn't think of it in terms of redundancy.  
22       This is so --

23                  MEMBER ABDEL-KHALIK: Well, the example you  
24       gave earlier pertained to loss of high-head safety  
25       injection, rather than loss of redundancy in the

1 ability to provide high-head safety injection, and you  
2 said, you know, even though the plant can depressurize  
3 and can use low-head safety injection, you don't allow  
4 the plant to operate in a condition where you don't  
5 have the ability to inject that high pressure. That's  
6 where the confusion came about.

7 MR. DUBE: In the tech specs, in the bases  
8 for the tech specs, they describe any -- this in great  
9 detail, and fine, okay. Then the bottom 9A is very  
10 similar, so in the interest of time, I won't go  
11 through it. But it's the same kind of a thing.

12 MEMBER ABDEL-KHALIK: As seven?

13 MR. DUBE: As seven. Core make-up tank and  
14 accumulator. The calculated completion time is 24  
15 days, but this configuration would not be allowed. So  
16 in all, many cases that were done, the staff did  
17 identify some configuration of equipment, outages that  
18 would represent ten years' worth of core damage  
19 probability.

20 Now that's a theoretical case, and in order  
21 to get this situation in the advanced boiling water  
22 reactor, for example, which is three divisions.

23 There's three electrical divisions; there's  
24 three trains of high pressure injection, three trains  
25 of low pressure injection, and then there's kind of an

1       unaffiliated division, if you will, such as the AC  
2       independent water addition, the containment vent and  
3       the reactor core isolation cooling, which is steam-  
4       driven.

5               To get these configurations, we were taking  
6       equipment almost across the board on all the  
7       divisions, to get in this situation. We were doing  
8       this to stretch the limit, but they weren't realistic  
9       conditions or situations.

10              In fact, there's not, you know, in many  
11       cases, under the tech specs, there's nothing  
12       prohibiting plants from being in similar  
13       configurations, and they have even less controls than  
14       if one implemented risk-informed tech specs.

15              MEMBER ABDEL-KHALIK: Can we go back to the  
16       previous slide?

17              MR. DUBE: Sure.

18              MEMBER ABDEL-KHALIK: I understand why this  
19       is not allowed change in the completion time, but  
20       where did the one hour come from in the first place?

21              MR. DUBE: That's in the tech specs right  
22       now. See the tech specs?

23              MEMBER ABDEL-KHALIK: I understand the tech  
24       spec, but just out of thin air.

25              MR. DUBE: Engineering judgment. Immediate

1 shutdown is really what it represents. I mean one  
2 hour is just enough time to think about --

3 MEMBER STETKAR: Same place that the 30 days  
4 came from.

5 MR. DUBE: Well, okay.

6 MEMBER BROWN: Can I ask one more question  
7 related to this?

8 MR. DUBE: Yes.

9 MEMBER BROWN: Is this meant to be a real-  
10 time tool, or this is a -- or that's another worry  
11 then. In other words, something happens in the plant,  
12 and now they go and they generate, they turn on their  
13 computer and say oh, I input the data and okay, I can  
14 stay in this convention for 20 days, as opposed to  
15 having it predetermined, based on so you can think  
16 about it, and see if it makes sense.

17 MR. DUBE: When I say "real time," it's real  
18 time in the sense that you're monitoring what  
19 equipment's out of service at any particular point in  
20 time. But you look, you know, we had South Texas in  
21 here, and they're the only ones that have implemented  
22 it so far, Units 1 and 2.

23 Those are Westinghouse 14-foot cores with  
24 three trains, and they pre-solved all the single  
25 equipment and many of the double combinations. So

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1 it's already been pre-calculated way ahead of time.

2 So they know, I mean you know, the plant's  
3 running along and all of a sudden the A HPSI pump is  
4 out. They know what the risk increase is without even  
5 doing the calculation yet. If something comes along  
6 and if it's aux feedwater pump, chances are they've  
7 pre-solved that.

8 So they already, when I say "online," it's  
9 online in the sense of it is an instantaneous  
10 monitoring of it, but most of the calculations for  
11 most of the configurations have already been done.

12 MEMBER STETKAR: Don, but that's only  
13 because South Texas decided to do it that way.  
14 Indeed, it could be if you had an online running PRA,  
15 you know, your standard risk monitor. This is a real  
16 time calculation.

17 MR. DUBE: Yeah, but if -- again, with South  
18 Texas' here is, you know, things happen odd hours.  
19 Three o'clock in the morning, you know, something's  
20 out and you have a tech spec that allows you three  
21 hours, four hours.

22 You know, you're going to call some PRA  
23 expert who's on vacation in Florida to do the  
24 calculation. You don't want to put yourself in that  
25 situation, so --

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1           MEMBER STETKAR: That's a different issue.  
2           But I think Charlie's concern was is this something  
3           that you do in real time, and the answer to that is  
4           yes.

5           MR. DUBE: The monitoring is real time.

6           MEMBER STETKAR: You make decisions in real  
7           time as the plant configuration changes. Regardless  
8           of whether it's pre-solved or you have your shift  
9           technical advisor is PRA-qualified, and he's running  
10          the risk model for you.

11          MR. DUBE: Right.

12          MEMBER STETKAR: This is real time  
13          decisions.

14          MR. BRADLEY: Yeah, that's correct. I just  
15          want to mention Vogtle 1 and 2 is in the process of  
16          applying for 4b, and they're using -- EPRI's produced  
17          an updated version of EOS, that will do a real time  
18          calculation to support the Vogtle 1-2 app.

19          MEMBER BROWN: How does the data get input?  
20          If something goes, I mean, is it monitored and it  
21          automatically happens, or does somebody have to input  
22          the fact that something else has failed or gone down  
23          while you've got some other operating configuration?

24          MR. BRADLEY: You have to input the data.  
25          It's an operator tool. It's in the control room.



1 It's just the operator, it's a tool for the operator.

2 MEMBER BROWN: Okay. So you subject  
3 yourself at three o'clock in the morning to the  
4 ability of a guy that may not be as good, if it's a  
5 system that's --

6 MEMBER STETKAR: Charlie, you turn something  
7 off.

8 MEMBER BROWN: Oh, I don't know. It could  
9 be anything. I have no idea.

10 MEMBER STETKAR: No, you turn something off.  
11 You've failed a piece of equipment. You aren't  
12 inputting failure rates for things. That's already in  
13 there. You're just --

14 MEMBER BROWN: Yep. Gotta make sure the  
15 data gets input correctly. That's all I -- that's the  
16 only point I'm making. You've got to make sure it  
17 gets input correctly.

18 MEMBER STETKAR: Well, but you do when you  
19 have a paper system and have to make decisions on the  
20 fly about whether or not you violate the tech specs.  
21 Somebody needs to recognize that something isn't  
22 working.

23 MEMBER BROWN: Yeah, but then you're  
24 recognizing it's not working. But you still have to  
25 input the data properly, even after you recognize it.

1                   MEMBER STETKAR: The data is turning  
2 something off.

3                   MM. I think all he's saying, Charlie, all  
4 I think he's saying is there would be a working model  
5 that best represents the plant, and then they'd look  
6 for essentially out of service conditions of the  
7 system. At least that's what I --

8                   MR. DUBE: Right. They would toggle a  
9 switch --

10                   (Simultaneous speaking.)

11                   MEMBER BROWN: Or it's knowing which switch  
12 to toggle.

13                   MR. DUBE: They're trained on this, and this  
14 is every operator. One reason why Luminant, on behalf  
15 of Comanche Peak 3 and 4 want to go straight to this,  
16 rather than use, go to standard tech specs and then  
17 have to get this program accepted down the line and  
18 have to retrain. Their goal is to start out with this  
19 Risk-Informed Tech Spec 4b, risk management tech specs  
20 right from the beginning, and train the operators  
21 right from the beginning.

22                   MEMBER BROWN: But the risk-informed output  
23 is still not going to output one hour. It would  
24 output 33. You've got to keep in mind that hold it,  
25 I'm in this other configuration --

1 MR. DUBE: No. There's software that  
2 handles that.

3 MEMBER BROWN: So it would come up one, if  
4 the software's written correctly. Line 7. If that  
5 really happened, and you had this online system and it  
6 went down, and the guy inputted it. Instead of coming  
7 up with 33 days, it would have said one hour.

8 MR. DUBE: Configuration 7 would, may take  
9 -- I can't speak on behalf of what might be designed  
10 into it, but --

11 MEMBER BROWN: As opposed to 30 days.

12 MR. DUBE: Yes, for that situation.

13 MEMBER STETKAR: So this by the way, the  
14 whole discussion that we're having here really is  
15 irrelevant to new reactors in particular, because it's  
16 being applied for existing reactors. RITS 4b is being  
17 applied for existing reactors. As Don mentioned,  
18 South Texas already has it in place. It is not a new  
19 reactor metrics issue, you know. Concerns about  
20 implementing this apply to currently operating  
21 reactors.

22 MEMBER BROWN: No, I understand that.

23 MR. DUBE: And during the workshop --

24 MEMBER BROWN: It had to be, since 3 and 4  
25 is not in place yet, and we talked about South Texas.

1 MR. DUBE: Right. During the workshop,  
2 South Texas was in before us and gave a demonstration  
3 of the experience capabilities. So I mentioned, you  
4 know, repeated entry would be a concern, but that's no  
5 different than the current tech specs, that allows  
6 multiple entries and doesn't even require the degree  
7 of monitoring that the program requires, RITS 4b.

8 And you know, in order to get these  
9 configurations that I mentioned, we were taking -- one  
10 would have to literally take equipment out from  
11 virtually all the trains, which is just not the way  
12 operators run plants. Typically, it's a one train at  
13 a time outage, and yeah, it could be an emergent  
14 failure on the second division, the second train. But  
15 extremely improbable to be the situation across all  
16 trains.

17 MEMBER BROWN: Is that what you mean by  
18 repeated entry?

19 MR. DUBE: No.

20 MEMBER BROWN: What did you mean by  
21 repeated? I didn't understand.

22 MR. DUBE: Right now a license has, let's  
23 say, a tech spec of three days on a diesel generator,  
24 and it's declared inoperable, enters the action  
25 statement, takes some action for one or two days. A

1 week or two later, some other configuration occurs,  
2 some other situation on the diesel. Enters the action  
3 statement, so that's one or two-three days.

4 MEMBER BROWN: In other words, it's not  
5 staying available?

6 MR. DUBE: Right. Whereas here, one of the  
7 requirements is to monitor performance over time. In  
8 fact, that's actually a requirement, and this is why  
9 I say, my third sub-bullet here, "Performance  
10 monitoring is a key programmatic control, and by  
11 regulation, the new reactors, under 50.71(h), have to  
12 maintain and upgrade the PRA," and part of that is  
13 monitoring performance.

14 I mean they have to -- if their past  
15 experience has been that these outages are  
16 contributing to train and unavailability, that has to  
17 be reflected in the PRA model. So we, the staff  
18 concluded after two days of exercises for the thought  
19 that there's no substantive changes to the methodology  
20 that's necessary.

21 Now there are some changes that might be  
22 necessary because of implementation issues, but  
23 they're not fundamental to the risk calculation.  
24 Probably I'm running way, probably running way behind  
25 time, and I know I was asked to, just in passing,

1 touch upon these.

2 So real quickly, one of the programs, one of  
3 the table tops had to do with the change process for  
4 severe accident features, and the black circles shows  
5 the containment challenges that are identified in  
6 52.47(a) (23) and 52.79.

7 These include specifically those five  
8 containment challenges from severe accidents. Core  
9 concrete interactions, steam exposure and high  
10 pressure, melt ejection, hydrogen explosion  
11 containment bypass.

12 But the statements of consideration, and in  
13 this case for the advanced boiling water reactor, is  
14 very specific on what is a next vessel severe accident  
15 feature, and they say it applies only to features  
16 where the intended function of the design feature is  
17 relied upon to resolve postulated accidents, when the  
18 reactor core has melted and exited the reactor vessel,  
19 and the containment is being challenged.

20 That's the red circle. So the change  
21 process under Tier 2 would definitely address features  
22 that are there to mitigate against core concrete  
23 interactions, high pressure melt ejection accidents.  
24 Steam explosion, maybe, maybe not. It wasn't specific  
25 whether it was an in-vessel steam explosion or ex-

1 vessel steam explosion.

2 In hydrogen explosion, it's not necessarily  
3 a situation occurs just because the core has melted  
4 through the bottom of the vessel and exited. So  
5 changes associated with that may or may not be  
6 included, and containment bypass, which is like an  
7 interfacing systems LOCA, are not, by definition, a  
8 feature, next vessel reaction feature.

9 So the long and short of it is when we went  
10 through this methodically, we found that the rule as  
11 written regarding the change process for ex-vessel  
12 severe accident leaves a gap.

13 There are severe accident features not there  
14 to address ex-vessel severe accidents, but to mitigate  
15 accidents and retain in in-vessel, that are there and  
16 the change process is not, there's a void. There's a  
17 gap. It doesn't say what to do with those.

18 MEMBER CORRADINI: Can you try that again?  
19 I'm trying to understand what you just said.

20 MR. DUBE: Okay. The rule says there  
21 cannot be an increase, substantial increase in  
22 probability or consequences of ex-vessel severe  
23 accidents. But it doesn't say anything about design  
24 features that are there to mitigate and keep the core  
25 in-vessel.

1           MEMBER CORRADINI: Now we're talking  
2           operating plants or future plants?

3           MR. DUBE: Just the new plants.

4           MEMBER CORRADINI: New plants.

5           MR. DUBE: It's part of the rule for the  
6           change process. So what does that mean? That means  
7           there's no guidance there for Tier 2 change process,  
8           or severe accident features that are there just for  
9           in-vessel mitigation.

10          MEMBER CORRADINI: So I guess you jumped to  
11          in-vessel, because I thought you were -- you started  
12          off what, there is no change process for ex-vessel.

13          MR. DUBE: No. There is a change process  
14          for ex-vessel severe accidents.

15          MEMBER CORRADINI: There is none for in-  
16          vessel?

17          MR. DUBE: Exactly. One would default -- in  
18          theory, a license holder could make a change to a  
19          severe accident design feature that's there, just to  
20          mitigate in-vessel accidents. For example, the  
21          independent water addition for the advanced cooling  
22          water reactor.

23                 Unless there was details in Tier 2, they  
24          could make a change under Tier, I mean unless there  
25          was specific details in Tier 1, they could make a



1 change under Tier 2 and not require prior NRC  
2 approval. You still look perplexed.

3 MEMBER CORRADINI: I am. I know what you  
4 said; I'm still trying to figure out. So that would  
5 not be reflected -- that is, they could do it without  
6 prior notification?

7 MR. DUBE: Prior NRC approval.

8 MEMBER CORRADINI: And that's what's bugging  
9 me.

10 MR. DUBE: Yes.

11 MEMBER CORRADINI: There's a gap. So in  
12 current plants --

13 MR. DUBE: Under the current regulation, a  
14 Tier 1 change is a very high level statement.

15 MEMBER CORRADINI: Yes, I understand.

16 MR. DUBE: They cannot make -- any change to  
17 that, even if it's somewhat minor, requires prior NRC  
18 approval. Tier 2, they go through a 5059 like  
19 process. Is there a substantial increase in  
20 probability or a substantial increase in consequences?

21 But it only applies to ex-vessel severe  
22 accident features, not features there to mitigate in-  
23 vessel phenomena.

24 MEMBER CORRADINI: Is the AP1000 in-vessel  
25 retention in-vessel or ex-vessel?

1           MR. DUBE: That would come under  
2 probability, and is there an increase in probability  
3 of an ex-vessel severe accident previously reviewed  
4 and deemed acceptable by the staff, and therefore  
5 deemed incredible.

6           MEMBER CORRADINI: It's a probability. It's  
7 not a feature that's a mitigation of consequence?

8           MR. DUBE: The flooding up of the lower  
9 reactor cavity, and cooling of the outside of the  
10 vessel is a feature to maintain the core debris inside  
11 the vessel. If they were to go through a -- so that  
12 --

13          MEMBER CORRADINI: Let's say they change the  
14 insulation, they change --

15          MR. DUBE: That makes high pressure melt  
16 ejection accidents incredible.

17          MEMBER STETKAR: I hate to stop this right  
18 now, but this actually is a really, really subtle part  
19 of what they dealt with, and I want to get to more of  
20 the risk metrics sort of issues, so we want to move  
21 off this point.

22          MR. DUBE: But in answer to your question,  
23 they did something so that they would not be able to  
24 have assurance of cooling the outside of the vessel  
25 and maintaining it. That would be a substantial

1 increase in probability and require prior NRC  
2 approval.

3 MEMBER CORRADINI: Okay, fine.

4 MR. DUBE: So Recommendation 1 to the  
5 Commission is to address the potential gap by ensuring  
6 there are sufficient details on all key safety  
7 accident features in Tier 1, and including a change  
8 process in future design certifications in Section  
9 VIII, for non-ex-vessel severe accident features  
10 similar to Section VIII.B.5.c.

11 So we have two here, because you know how  
12 long it takes a rulemaking. It takes a lot of time.  
13 So in the interim, we want to change, have ensure, and  
14 we can do this by changing one of our standard review  
15 plan items, if you will, relatively quickly.

16 So we can ensure that there's sufficient  
17 details in Tier 1, but the long-term would be design  
18 certification rulemaking, to make sure that features  
19 to arrest and mitigate core damage in-vessel get the  
20 same treatment as ex-vessel, the long and short of it.

21 A second item in passing has to do with the  
22 fact that for design certifications, large early  
23 release frequency has been the metric, and in the  
24 interest of time, because I'm really running out fast,  
25 as part of our exercises, the staff's recommending an

1 option where one would convert from the use of large  
2 early release frequency, and leave that to design  
3 certification and combined license application, at or  
4 around the issuance of the combined license and during  
5 the construction phase.

6 Core damage frequency, large early release  
7 frequency and conditional containment failure  
8 probability would still be the metrics of use, but at  
9 or before initial fuel load, to be consistent with  
10 large early release frequency, which is the metric  
11 that operating reactors are using.

12 The COL holder would convert from large  
13 early release frequency to use of large early release  
14 frequency metric.

15 MEMBER STETKAR: Now that last bullet, and  
16 I want to keep us on schedule here, but the last  
17 bullet is also important, because the recommendation  
18 also says that Reg Guide 1.174 will be updated to note  
19 the containment performance also. Although you don't  
20 calculate a CCFP, that notion will be retained.

21 MR. DUBE: Right. There's two Commission  
22 papers, and there's an associated staff requirements  
23 memorandum, 90-016 and 93-087, which have to do with  
24 containment performance objectives, and I'll just  
25 really read it quickly.

1           "The containment should maintain its role as  
2     a reliable leak-tight barrier, for example, by  
3     ensuring that containment stresses do not exceed ASME  
4     service level C limits for metal containments, or  
5     fractive (ph) load category for concrete containments  
6     for approximately 24 hours following the onset of  
7     core damage, under the more likely severe accident  
8     challenges," and so on and so forth. So they would  
9     still have to meet that requirement.

10           So those are the two recommendations.  
11     They're kind of ancillary to many of the table top  
12     exercises, but they were findings as a results of the  
13     table top exercises. You know one, is that there was  
14     a gap in the change process that didn't address  
15     mitigation of in-vessel phenomena, and the second one,  
16     new reactors and operating reactors are using two  
17     metrics, and at some point, the Commission told us  
18     make them the same.

19           So at some point they have to transition,  
20     and Option 2C, Recommendation 2 is what staff has  
21     proposed. I'm just going to list here to note that we  
22     looked at the maintenance rules, 50.65(a)94). We  
23     found no gaps. We looked at Risk-Informed Tech Spec  
24     Initiative 5b on surveillance frequency, found no  
25     gaps.

1           We looked at 50.69, and no gaps, and Reg  
2           Guide 1.174, other than that one point that I made on  
3           containment performance. But in terms of the risk  
4           metrics and reliance on defense indepth, we found no  
5           gaps.

6           Now I'm going to -- unless there's  
7           questions, I'll turn it over Ron Fruhm, who will talk  
8           about the ROP.

9           MR. FRUHM: Okay, and I'll try to do this  
10          fairly quickly, based on time constraints, because we  
11          do still want to talk about next steps, and quickly  
12          review some of the changes we made to the draft SECY  
13          paper.

14          I'm Ron Fruhm in the Performance Assessment  
15          Branch of NRR. I just wanted to recognize that Rani  
16          Franovich is also with us today. She's the branch  
17          chief of that branch.

18          In addition to those licensing table tops  
19          that Don's been talking about, we ran several case  
20          studies on the risk-informed aspects of the reactor  
21          oversight process, to confirm their adequacy for use  
22          for new reactors.

23          We used a broad cross-section of real cases  
24          from the previous ten or so years of ROP experience,  
25          to ensure a realistic and representative sample,

1       because the SRM did say that we should do realistic  
2       scenarios.

3               The case studies covered the significance  
4       determination process for the risk-informed safety  
5       cornerstones of initiating events, mitigating systems  
6       and barrier integrity. We also ran case studies on  
7       the mitigating systems performance index and  
8       Management Directive 8.3 for regulatory response to  
9       events.

10              We then applied similar situations based on  
11       those case studies to the new reactor designs, filling  
12       in any gaps with realistic hypothetical situations and  
13       reasonable assumptions. Then we compared the risk  
14       values and resultant regulatory response, to see if we  
15       ended up in the right place.

16              A summary of these case studies was included  
17       as an enclosure to the October 26th meeting summary.

18              The first set of table tops we ran was for  
19       the significance determination process. These table  
20       tops indicated that the existing risk thresholds for  
21       determining the significance of inspection findings  
22       are generally acceptable, and greater than green  
23       thresholds could be crossed, but would produce an  
24       increased regulatory response.

25              However, these greater than green inspection

1 findings would likely involve common cause failures  
2 across multiple systems or long exposure times of  
3 risk-significant components.

4 Further, we found that the existing process  
5 would not always ensure an appropriate regulatory  
6 response for degradation of passive components and  
7 barriers. So for the SDP, we concluded that these  
8 analyses could be augmented with additional  
9 qualitative considerations, such as deterministic  
10 backstops, to appropriately address the performance  
11 issues.

12 As noted in the draft paper, some of the  
13 potential deterministic backstops could include an  
14 emphasis on barrier integrity, limiting extensive  
15 equipment outage times, similar to the RITS 4b that  
16 Don talked about, and addressing repetitive or common  
17 cause equipment failures.

18 I would like to point out that the backstops  
19 would be designed to capture those infrequent yet  
20 potentially significant issues that may not be  
21 captured directly by the risk calculations, in order  
22 to ensure that we end up in the right place with our  
23 regulatory response.

24 Next, the second set of table tops was for  
25 MD 8.3 for event response, and these table tops



1 demonstrated that the existing risk thresholds for  
2 invoking reactor inspections are adequate for the new  
3 reactor, and these thresholds could be crossed, such  
4 that we would invoke reactive inspections, including  
5 augmented inspection teams.

6 They did reveal that the deterministic  
7 criteria already play an important role in this  
8 process, but they are used initially for event  
9 screening, and are then considered again within a  
10 range of response determined by the risk values.

11 So as a result of this current structure,  
12 which applies to the current fleet as well, the risk  
13 values heavily influence whether or not a reactive  
14 inspection is warranted, and at what level we would  
15 engage.

16 We also noted that variations in or minor  
17 revisions to the risk models used could potentially  
18 result in an inadequate response. Based on the MD 8.3  
19 table tops, we concluded that the contribution of the  
20 existing criteria could be modified, or new  
21 deterministic criteria could potentially be developed  
22 for initiating reactor inspections for new reactors,  
23 similar to those previously discussed for the SDP.

24 The third set of table tops we ran for the  
25 ROP was for the MSPI, and quite conclusively, we

1 realized that the existing MSPI would be largely  
2 ineffective in determining an appropriate regulatory  
3 response for active new reactor designs, and a  
4 meaningful MSPI might not even be possible for the  
5 passive designs.

6 We did note that the existing performance  
7 limit or backstop used in the MSPI process could  
8 potentially be further leveraged for the active new  
9 reactor designs, and so our conclusion for the MSPIs  
10 was that alternate PIs in the mitigating systems  
11 cornerstone could be developed, or additional  
12 inspection could be used for the new reactors, to  
13 supplement insights currently gained through the MSPI  
14 for the current fleet.

15 MEMBER SKILLMAN: Ron, back on that slide,  
16 number 20 please. With the result that the existing  
17 MSPI is not adequate and would be ineffective, why in  
18 your conclusion do you communicate that an alternate  
19 PI could be developed, versus should be developed?

20 MR. FRUHM: Well should is more like a  
21 recommendation to me. Here, our conclusions, our  
22 recommendation is that it should be developed, if that  
23 helps.

24 MEMBER SKILLMAN: Well then why isn't the  
25 wording "must be," just so it's clear?

1 MS. FRANOVICH: This is Rani Franovich from  
2 the staff. I don't know that the staff really has  
3 established a position on this.

4 I think what we really need to do is work  
5 with the industry and other external stakeholders, to  
6 get a better feel for what kinds of PIs might be  
7 leveraged, what it would look like, and then determine  
8 if that's really going to be adequate, or do we need  
9 to look in the inspection area to cover that.

10 So we're not tied to PI. If we find that  
11 there is a viable approach to an alternative PI, then  
12 that's great. The other thing is the industry has to  
13 be agreeable. So using inspection is another way to  
14 do this.

15 MEMBER SKILLMAN: Okay, thank you.

16 MR. FRUHM: And we are just talking the  
17 mitigating systems cornerstone here. That's one of  
18 the seven cornerstones, and within each cornerstone  
19 there are PIs and inspections.

20 MEMBER SKILLMAN: Okay, thank you. Thanks.

21 MR. FRUHM: Okay. So based on the table top  
22 results, we developed three options for the  
23 Commission's consideration. Consistent with the SRM  
24 direction, each of these options maintains the current  
25 risk thresholds for the new reactor designs.

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1           They're also consistent with the integrative  
2 risk-informed decision-making concepts in Reg Guide  
3 1.174, and in addition, they would not infringe upon  
4 the greater operational flexibility afforded by the  
5 enhanced safety margins of the new reactor designs.

6           Under the first option, use as is, we would  
7 simply use the existing risk-informed tools for new  
8 reactor applications without making any changes. An  
9 obvious advantage to this approach is that no  
10 additional action or resources would be needed. But  
11 a pretty obvious disadvantage is that these existing  
12 tools might not always provide for an adequate  
13 regulatory response.

14           MEMBER STETKAR: Ron, for the benefit of the  
15 -- again, for the Committee members who weren't in the  
16 Subcommittee meeting, we had -- I had to wait until we  
17 got here -- quite a bit of discussion about kind of  
18 what feeds into that second bullet under A, and I want  
19 to make sure I understand it pretty clearly.

20           I mean the way that you interpreted the SRM  
21 was a very literal interpretation of the SRM. In  
22 other words, whatever is spelled out in the current  
23 regulations is what was applied. In particular, for  
24 example in the significance determination process,  
25 there are absolute measures that are used.

1           If the core damage frequency increases by  
2           1.0 times 10 to the minus 6, or if the large early  
3           release frequency increases by 1.0 times 10 to the  
4           minus 7, you transition from bringing \*\*. Those are  
5           absolute measures of the change, and some of your  
6           examples demonstrated that it's extremely difficult to  
7           meet those absolute changes in risk.

8           We questioned in the Subcommittee why not  
9           use relative changes in risk, for example, the risk  
10          increase by a factor of 10 or 100 or 1,000 or two  
11          percent.

12          I think the response that we heard was well,  
13          that's not the way the current regulatory guides are  
14          fashioned. So that was beyond that you thought about.  
15          Is that a fair characterization?

16          MR. FRUHM: That's fair. We did interpret  
17          it very strictly. That was based on the words  
18          themselves, as well as looking back at the vote sheets  
19          from the Commissioners and all of our interactions  
20          with stakeholders. We were all looking at it from the  
21          same angle, and that was that the risk thresholds were  
22          -- they were what they were.

23          Test them, see where we come out, and if  
24          they're grossly off base, then we need to, you know,  
25          come up with examples and really convince them. And

1 basically they said no, but you know, if you really  
2 find something wrong, come back to us and convince us,  
3 and we didn't feel like we got there.

4 MEMBER STETKAR: Okay. You didn't look at  
5 -- I mean we discussed using type relative measures.

6 MR. FRUHM: We never considered relative  
7 risk in that, as we discussed during the Subcommittee.

8 MEMBER STETKAR: I just, the other Committee  
9 members didn't have the benefit of that discussion,  
10 and we're kind of limited on time here, but thanks.

11 MS. FRANOVICH: This is Rani Franovich. If  
12 I could just interject, I'm a little concerned that if  
13 we even propose that eight percent change in the risk,  
14 the relative risk, could be perceived by the  
15 Commission as a back door way of really establishing  
16 new risk thresholds for new reactors. A factor of ten  
17 is really a factor of ten reduction in the risk.

18 So we really did not consider that as a  
19 viable option that the Commission left on the table.  
20 But that was just the staff's read, based on, as Ron  
21 said, the vote sheets and the SRM.

22 MEMBER STETKAR: Thanks.

23 MR. FRUHM: That would be more towards  
24 Option 3 from the original paper.

25 MEMBER STETKAR: Right.

1 MR. FRUHM: And we saw it as -- they said  
2 Option 1 or 2 are hybrids, so we kind of left that off  
3 the table.

4 MEMBER STETKAR: Thanks, Ron.

5 MR. FRUHM: Okay. Moving on to the second  
6 option. Option B is to augment the existing  
7 processes. Here, we would use the existing risk-  
8 informed SDP, but augment the risk aspects with  
9 deterministic backstops, to ensure an appropriate  
10 regulatory response to address performance issues.

11 We would modify the contribution of the  
12 existing deterministic criteria in Management  
13 Directive 8.3, or potentially develop new criteria, to  
14 determine the appropriate regulatory response to plant  
15 events.

16 Finally, we would develop an alternative PI  
17 and a mitigating systems cornerstone, or argument  
18 existing guidance to emphasize the performance limit,  
19 or increase inspections for the active new reactor  
20 designs, and we would also increase the inspection of  
21 passive mitigating systems for the passive new  
22 reaction designs, because we do have both PIs and  
23 inspections as approaches to evaluate performance.

24 A key advantage of this option is that you  
25 probably noticed that it nicely aligns with the

1 conclusions from the previous slides. Another  
2 advantage is that these proposed enhancements could be  
3 developed using existing resources, and working with  
4 stakeholders over the next few years, well in advance  
5 of the operation of new reactors.

6 They do, however, introduce more qualitative  
7 decisions with regard to not yet developed  
8 deterministic backstops, as they're presented here,  
9 which in some sense seems to be a retreat from the  
10 whole notion of developing a quantitative risk-  
11 informed regulatory framework.

12 The reason quantitative is nice is it's  
13 well-defined. It's unbiased and it's reproducible, as  
14 opposed to my making a determination of how you may or  
15 may not comply with some well-defined or not so well-  
16 defined deterministic criterion.

17 MEMBER STETKAR: Right. Well, that's a bit  
18 of -- we had some of this discussion also in the  
19 Subcommittee meeting, that it seems a bit of a retreat  
20 from that process that was implemented, and has been  
21 working quite well, you know, with the existing  
22 reactor fleet.

23 MR. FRUHM: And we still will be extremely  
24 risk-informed. That's one of the tenets of the ROP,  
25 to be risk-informed, and we want to be repeatable,

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1       etcetera. These deterministic backstops will not be  
2       subjective.

3               We'll try to make them as repeatable and,  
4       you know, concrete as we can. We would not make for  
5       subjective decision-making. It would be a value, a  
6       numeric threshold we would envision it to be. That's  
7       what we would envision today. I mean obviously we  
8       haven't gone through the process, but that's what  
9       we're thinking.

10              MS. FRANOVICH: Yeah. If I could interject  
11       here too, Rani Franovich. There are four other  
12       cornerstones of the ROP that don't rely on risk tools,  
13       but we still consider the outcomes of SDP to be  
14       repeatable, because we use the same deterministic  
15       process for each case, to arrive at a significance  
16       outcome.

17              I think that that would still be true in  
18       this case, although that would be for those few cases  
19       where the backstops are achieved. I think most cases  
20       will be resolved and characterized with the risk  
21       threshold that we have in place today.

22              MR. FRUHM: In fact, we would envision  
23       applying the same guidance to both the current fleet  
24       and the new reactor fleet. But we would expect the  
25       risk thresholds would be tripped more frequently for

1 the current reactors, and we probably never would get  
2 to those deterministic backstops. For the new  
3 reactors, we would get there on occasion, but also not  
4 frequently.

5 Okay. Moving on to the next slide, the  
6 third and final option, Option C, is to develop  
7 deterministic tools, where we would essentially not  
8 use the existing risk-informed ROP tools, but would  
9 instead develop deterministic tools specifically  
10 designed for the new reactors.

11 An obvious advantage to this is that, or a  
12 disadvantage is that additional resources would be  
13 necessary, and another disadvantage is that this  
14 approach would be less risk-informed than it is for  
15 the current fleet.

16 Probably as no surprise, we would recommend  
17 Option D, to augment the existing processes, and going  
18 this route, we would obtain Commission approval for  
19 any proposed changes to the ROP at least one year  
20 prior to implementation, and the process enhancements  
21 could be further refined over the years, based on  
22 experience and lessons learned, which is consistent  
23 with the continuous improvement philosophy of the ROP.  
24 That really concludes the ROP portion of the  
25 presentation.

1 MR. DUBE: Yeah, we're pretty much done. I  
2 would just --

3 MR. FRUHM: I'll turn it over to Don to wrap  
4 it up.

5 MR. DUBE: The next two steps, that's all  
6 that's left after several years of working on this  
7 effort. Finalize the Commission paper based on ACRS  
8 and stakeholder feedback. The paper is due to the EDO  
9 end of May; to the Commission early June.

10 As of now, we've only had positive feedback  
11 from external stakeholders, and so we're not planning  
12 any changes on that account. We're not planning as of  
13 now to make any substantive changes to the draft. We  
14 have, you know, been making continuously editorial  
15 changes. We've made wording changes.

16 I know some Subcommittee members expressed  
17 some concern with words about the PRAs, so the use of  
18 PRA in the ROP in particular. We've made those  
19 changes already.

20 We've shortened it, and under Recommendation  
21 1, at one time there was an option 1A and 1B, which is  
22 either fill the gap for the ex-vessel severe accident  
23 change process, or don't fill the gap. It's kind of  
24 a little bit of a non-choice. So we just eliminated  
25 the option and just made the recommendation.

1 MEMBER STETKAR: Don, that's kind of  
2 important, because we will be writing a letter from  
3 this meeting, and the letter that we're writing will  
4 be referenced to the February 3rd version of the SECY  
5 paper, which is the only thing that we've seen, and  
6 that one's still -- for example, I noticed 1A and 1B  
7 have disappeared, and it's only 1 now.

8 MR. DUBE: Yeah, right.

9 (Simultaneous speaking.)

10 MEMBER STETKAR: So we've not seen any  
11 editorial changes since that February 3rd revision  
12 version?

13 MR. DUBE: Right.

14 MEMBER STETKAR: So just to make you aware  
15 of that. I mean you said there's nothing substantive  
16 that's been changed.

17 MR. DUBE: Well, when I say --

18 MEMBER STETKAR: We're limited to anything  
19 you see from us in our letter.

20 MR. DUBE: Okay. The conclusions are the  
21 same. The background's the same. Like I said, I  
22 don't know if you call that substantive, but we  
23 deleted Option 1A and 1B, and just used the same  
24 arguments to go straight to the Recommendation 1.

25 MEMBER STETKAR: That's fine. Just you'll

1 see, for example in our letter, a discussion of 1A and  
2 1B, you know, if the Committee so decides to cast it  
3 that way. Just because our version of record is  
4 indeed that February 3rd version.

5 So we'll take it on face value, that there  
6 hasn't been anything substantively changed, that would  
7 make us look really silly.

8 MR. DUBE: No. For advantages and  
9 disadvantages, the reasoning behind both the  
10 conclusions, the recommendations, both haven't  
11 changed. Thanks.

12 MEMBER STETKAR: Great. Any other members  
13 have any other questions, comments? I'm sure there  
14 are comments, but anything else?

15 MALE PARTICIPANT: Nothing.

16 MEMBER STETKAR: If not, amazingly enough,  
17 Mr. Chairman --

18 CHAIR ARMIJO: Right on time.

19 MEMBER STETKAR: Oh, we're early. Twenty  
20 minutes early.

21 MALE PARTICIPANT: I've got credit in the  
22 bank.

23 (Simultaneous speaking.)

24 MEMBER POWERS: Those four minutes are my  
25 four minutes.



# Presentation to the ACRS Full Committee – 593<sup>rd</sup> Meeting

**Briefing on Calvert Cliffs Unit 3 COL Application Safety Evaluation Reports with Open Items for FSAR Chapters 6, 7, 15, and 18**

**Surinder Arora  
Project Manager**

**April 12, 2012**

# Major Milestones - Chronology



DATE	MAJOR MILESTONE
07/13/2007	Part 1 of the COL Application (Partial) submitted
12/14/2007	Part 1, Rev. 1, submitted
03/14/2008	Part 1, Rev. 2, & Part 2 of the Application submitted
08/01/2008	Revision 3 submitted
03/09/2009	Revision 4 submitted
06/30/2009	Revision 5 submitted
07/14/2009	Review schedule published
09/30/2009	Revision 6 submitted
04/12/2010	Phase 1 review completed
12/20/2010	Revision 7 submitted
11/15/2011	ACRS reviews complete for Chapters 2 (Group I), 4, 5, <b>6, 7</b> , 8, 10, 11, 12, <b>15</b> , 16, 17, <b>18</b> & 19
03/27/2012	Revision 8 submitted

# Review Schedule

Phase - Activity	Target Date
<b>Phase 1</b> - Preliminary Safety Evaluation Report (SER) and Request for Additional Information (RAI)	April 2010 (Actual)
<b>Phase 2</b> - SER with Open Items	Schedule under Review
<b>Phase 3</b> – Advisory Committee on Reactor Safeguards (ACRS) Review of SER with Open Items	Schedule under Review
<b>Phase 4</b> - Advanced SER with No Open Items	Schedule under Review
<b>Phase 5</b> - ACRS Review of Advanced SER with No Open Items	Schedule under Review
<b>Phase 6</b> – Final SER with No Open Items	Schedule under Review

NOTE: The target dates for Phase 2 to 6 are currently being evaluated based on the RAI response dates provided by UniStar in their February 21, 2012 letter.



# Review Strategy

- Pre-application activities
- Acceptance Review of the application
- COLA has chapters and sections incorporated by Reference
- Review of COLA site specific information in conjunction with the DC review. Same technical reviewers in most cases.
- Generic Open Item that ties DC and COLA Reviews
- Frequent interaction with the applicant via
  - ♦ Teleconferences
  - ♦ Audits
  - ♦ Public meetings
- Use of Electronic RAI (eRAI) System
- Phase discipline

# Summary of SER with OI: Chapter 6 Engineered Safety Features

SRP Section/Application Section		Number of RAI Questions	Number of SE Open Items
6.1.1	Metallic Materials	1	0
6.1.2	Organic Materials	3	0
6.2.1 6.2.2 6.3	Containment Functional Design Containment Heat Removal Emergency Core Cooling System	These Sections were not delivered in the Phase 2 SE	N/A
6.2.3 6.2.4 6.2.5 6.2.7 6.5	Secondary Containment Functional Design Containment Isolation System Combustible Gas Control in CTMT Fracture Prevention of CTMT Pressure Vessel Fission Product Removal & Control Systems	IBR	0
6.2.6	Containment Leakage Testing	0	0
6.4	Habitability Systems	6	2
6.6	Inservice Inspection of ASME Class 2 & 3 Components	0	0
Totals		10	2

# Summary of SER with OI: Chapter 7 Instrumentation and Controls

SRP Section/Application Section		Number of RAI Questions	Number of SE Open Items
7.1	Introduction	2	0
7.5	Information Systems Important to Safety	2	2
7.7	Control Systems	1	1
7.9	Data Communication Systems	1	0
Totals		6	3

# Summary of SER with OI: Chapter 15 Transient and Accident Analyses

SRP Section/Application Section		Number of RAI Questions	Number of SE Open Items
15.0	Transient and Accident analysis (except Section 15.0.3)	0	0
15.0.3	Radiological Consequences of Design Basis Accidents	1	0
Totals		1	0

# Summary of SER with OI: Chapter 18

## Human Factors Engineering

SRP Section/Application Section		Number of RAI Questions	Number of SE Open Items
18.8	Procedure Development	1	0
18.12	Human Performance Monitoring	1	0
Totals		2	0

1 CHAIR ARMIJO: You want to say something?

2 MEMBER POWERS: I started us off four  
3 minutes early.

4 CHAIR ARMIJO: That's true, that's true.  
5 Thank you very much. Okay. Well look. I think we  
6 can afford to take about a five minute break, in  
7 addition to the four minutes we have. So let's say  
8 five after.

9 MALE PARTICIPANT: Ten after.

10 CHAIR ARMIJO: Five after, okay, and we will  
11 get the letters. Thank you much.

12 (Whereupon, at 3:56 p.m., the meeting was  
13 concluded.)

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# UNISTAR NUCLEAR ENERGY

**Presentation to ACRS Full Committee  
U.S. EPR™  
Calvert Cliffs Nuclear Power Plant Unit 3  
FSAR Chapters 6, 7, 15 & 18  
SER with Open Items  
April 12, 2012**



# Introduction



- Mark Finley, Senior Vice President, Regulatory Affairs & Engineering, will lead the Calvert Cliffs Unit 3 presentation.
- Presentation was prepared by UniStar and is supported by:
  - Vincent Sorel (UniStar – Director Regulatory Affairs PRA & EPR Design)
  - Sebastien Thomas (UniStar – Manager of Nuclear Engineering)



# Calvert Cliffs Unit 3 Overview



<u>Calvert Cliffs Unit 3 Summary</u>				
<u>Chapter</u>	<u># Departures</u>	<u>#Exemptions</u>	<u># SER Open Items</u>	<u># SER Open Items Responses Submitted</u>
6	1	1	2	2
7	0	0	3	2
15	1	1	0	N/A
18	1	0	0	N/A
Totals	3	2	5	4

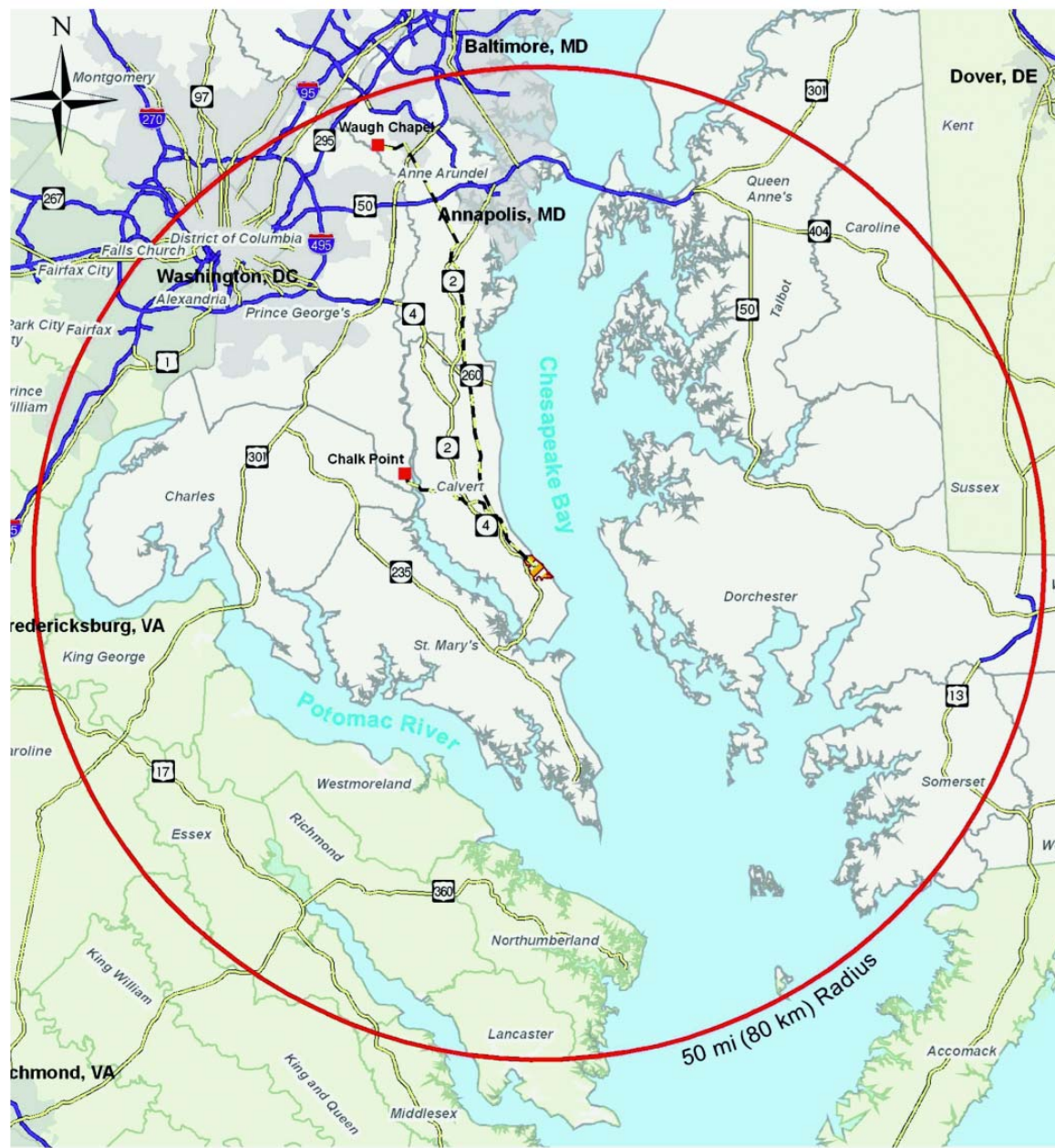


# **Calvert Cliffs Unit 3 ACRS Full Committee Meeting Introduction**

- UNE is responsible for the design of Calvert Cliffs Unit 3 and develops the design primarily through contracts with Bechtel and AREVA who have joined in a Consortium to develop the detailed design of the US EPR.
- RCOLA authored using 'Incorporate by Reference' (IBR) methodology.
- The focus of today's presentation will be a summary of the second set (four) of FSAR Chapters that have been presented to the U.S. EPR ACRS Subcommittee.
- The initial Calvert Cliffs Unit 3 ACRS Full Committee meeting, addressing the first set (9½) of FSAR Chapters, was conducted on April 7, 2011.
- For today's presentation only supplemental information, or site-specific information, departures or exemptions from the U.S. EPR FSAR are discussed.







# List of Chapters



- Chapter 6, Engineered Safety features
- Chapter 7, Instrumentation and Controls (I&C)
- Chapter 15, Transient & Accident Analysis
- Chapter 18, Human Factors Engineering (HFE)

# ACRS Full Committee Meeting Agenda

- Chapter 6
  - Departure/Exemption
  - Summary
- Chapter 7
  - Site-specific Post Accident Monitoring Variables
  - Summary
- Chapter 15
  - Departure/Exemption
  - Summary
- Chapter 18
  - Departure
  - Summary
- Conclusions

# Chapter 6

## Engineered Safety Features

### Departure and Exemption



- Habitability Systems – Main Control Room, Toxic Chemicals
  - For Calvert Cliffs Unit 3, the detection of toxic gases and subsequent automatic isolation of the Control Room Envelope (CRE) is not required and is not a part of the site-specific design.
    - The evaluation of the Calvert Cliffs Unit 3 toxic chemicals in Calvert Cliffs Unit 3 FSAR Section 2.2.3 did not identify any credible toxic chemical accidents that exceeded the limits established in Regulatory Guide 1.78.
    - No specific provisions are required to protect the operators from an event involving a release of a toxic gas.
    - Therefore, Seismic Category 1/Class 1E toxic gas detectors and automatic isolation are not required and will not be provided at Calvert Cliffs Unit 3.



## **Chapter 6**

# **Engineered Safety Features Summary**

- COL Information Items, as specified by U.S.EPR FSAR, are addressed in Calvert Cliffs Unit 3 FSAR Chapter 6
- One Departure/Exemption from U.S. EPR FSAR
- No ASLB Contentions
- There are two (2) SER Open Items and responses have been submitted (March 25, 2011).
- There are three (3) Confirmatory Items and they have been incorporated into the COLA (Revision 05).



# ACRS Full Committee Meeting Agenda

- Chapter 6
  - Departure/Exemption
  - Summary
- Chapter 7
  - Site-specific Post Accident Monitoring Variables
  - Summary
- Chapter 15
  - Departure/Exemption
  - Summary
- Chapter 18
  - Departure
  - Summary
- Conclusions

# Chapter 7

## Instrumentation and Controls

### PAM Variables



- Site-specific Post Accident Monitoring (PAM) Variables
- ✓ PAM variables supplemented with site specific variables
  - Ultimate Heat Sink (UHS) Tower Basin water level
  - Meteorological data
- ✓ PAM variables list confirmed prior to fuel load after completion of the Emergency Operating procedures (EOPs) and Abnormal Operating Procedures (AOPs)

# Chapter 7

## Instrumentation and Controls

### Summary



- All COL Information Items, as specified by U. S. EPR FSAR, are addressed in Calvert Cliffs Unit 3 FSAR Chapter 7, Instrumentation and Controls.
- No Departures/Exemptions from the U.S. EPR FSAR for Chapter 7 of the Calvert Cliffs Unit 3 FSAR
- No ASLB Contentions
- There are three SER Open Items and No Confirmatory Items
- The responses to two SER Open Items (RAI 326 and RAI 325 Question 07.05-2) have been submitted and the response to the remaining Open Item is in progress. (RAI 325 Question 07.05-1)

# ACRS Full Committee Meeting Agenda

- Chapter 6
  - Departure/Exemption
  - Summary
- Chapter 7
  - Site-specific Post Accident Monitoring Variables
  - Summary
- Chapter 15
  - Departure/Exemption
  - Summary
- Chapter 18
  - Departure
  - Summary
- Conclusions

# Chapter 15

## Transient and Accident Analysis

### Departure/Exemption




#### ➤ Site Specific $\chi/Q$ Values

- Conservative estimates of atmospheric Accident values for the Exclusion Area Boundary (EAB), Low Population Zone (LPZ) and Main Control Room are presented in the U.S. EPR FSAR and bound the Calvert Cliffs Unit 3 values except the 0-2 hour value for the LPZ.
- The U.S.EPR FSAR provides the Accident  $\chi/Q$  of  $1.75\text{E-}04 \text{ sec/m}^3$  at the LPZ - 1.5 miles during the 0-2 hr period. The corresponding calculated site-specific short-term atmospheric dispersion factor for Calvert Cliffs Unit 3 is  $2.15\text{E-}04 \text{ sec/m}^3$  which exceeds/departs from the U.S. EPR value.
- The site-specific Accident Dispersion factors were used in calculating doses from accident scenarios specified in the U.S. EPR FSAR Chapter 15. Calvert Cliffs Unit 3 doses are conservatively within the limitations of 10 CFR 50.34 and GDC 19.

# Chapter 15

## Transient and Accident Analysis

### Departure/Exemption



**Table 15.0-2— {CCNPP Unit 3 LPZ Radiological Consequences of U.S. EPR Design Basis Accidents}**

Design Basis Accident		Offsite Dose CCNPP Unit 3 LPZ rem (TEDE)	Acceptance Criterion rem (TEDE)
LOCA		9.1	25
Small line break outside of Reactor Building		0.4	2.5
SGTR	Pre-incident spike	0.3	25
	Coincident spike	0.3	2.5
MSLB	Pre-incident spike	0.1	25
	Coincident spike	0.2	2.5
	Fuel rod clad failure	2.6	25
	Fuel overhear	2.8	25
RCP locked rotor/broken shaft		0.9	2.5
Rod ejection		3.4	6.3
Fuel handling accident		1.2	6.3

# **Chapter 15**

## **Transient and Accident Analysis**

### **Summary**



- One COL Information Item, as specified by U. S. EPR FSAR, is addressed in Calvert Cliffs Unit 3 FSAR Chapter 15, Transient and Accident Analysis.
- One Departure/ One Exemption in Chapter 15 from the U.S. EPR FSAR for Chapter 15 of the Calvert Cliffs Unit 3 FSAR
- There are no NRC SER Open Items or Confirmatory Items
- No ASLB Contentions
- Responses to all RAIs have been submitted.

# ACRS Full Committee Meeting Agenda

- Chapter 6
  - Departure/Exemption
  - Summary
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  - Summary
- Chapter 18
  - Departure
  - Summary
- Conclusions



# Chapter 18

## Human Factors Engineering Departure



- Human Performance Monitoring (HPM) Program - Departure
  - The U.S. EPR HPM is replaced by the UniStar HPM Program entirely
  - The key differences are summarized below:
    - An Operational Focus Aggregate Index is used to trend performance of key variables that can impact Operations Human Performance
      - ✓ Aligns with INPO 09-011, Achieving Excellence in Performance Improvement
      - UniStar Corrective Action Program is utilized:
        - ✓ To track HFE issues in lieu of a separate program (HFE issue tracking system)
    - The UniStar Nuclear Energy Human Performance Monitoring Program meets the requirements of NUREG - 0711

# **Chapter 18**

## **Human Factors Engineering**

### **Summary**

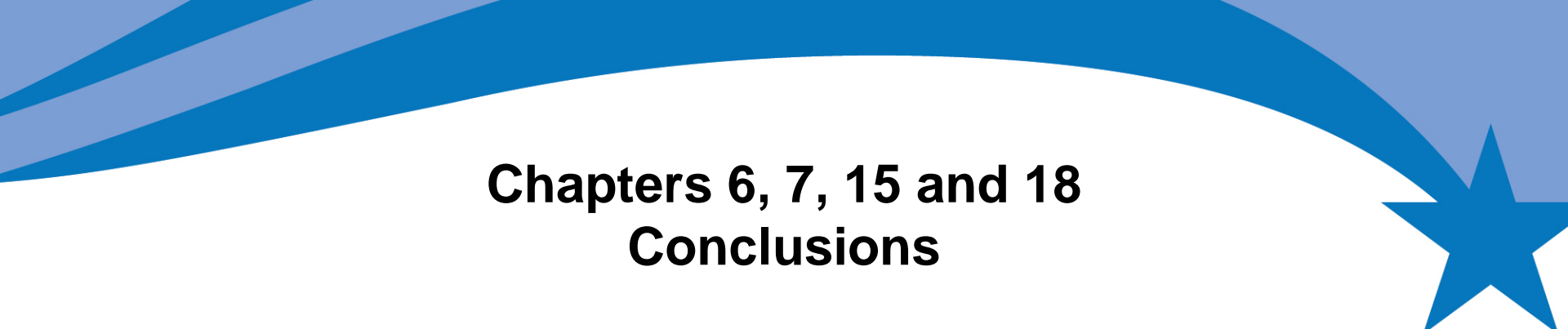


- Five COL Information Items, as specified by U.S. EPR FSAR, are addressed in Calvert Cliffs Unit 3 FSAR Chapter 18
- No ASLB Contentions
- The Departure from the U.S. EPR Human Performance Monitoring Program implements the requirements of NUREG - 0711
- No SER Open Items
- All RAI responses have been submitted
- There are two SER Confirmatory Items and they have been incorporated into the COLA (Revision 08)

# ACRS Full Committee Meeting Agenda

- Chapter 6
  - Departure/Exemption
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- Chapter 7
  - Site-specific Post Accident Monitoring Variables
  - Summary
- Chapter 15
  - Departure/Exemption
  - Summary
- Chapter 18
  - Departure
  - Summary
- **Conclusions**

## Chapters 6, 7, 15 and 18 Conclusions



- No ASLB Contentions
- There are three (3) departures and two (2) exemptions
- All Confirmatory Items have been incorporated in the COLA (Revision 08)
- Responses have been submitted to four (4) of the five (5) SER Open Items. The response to the remaining SER Open Item is in progress
- As of April 12, 2012, thirteen and one-half (13½) of the nineteen (19) Chapters of the Calvert Cliffs Unit 3 FSAR have completed Phase 3

# Acronyms

- **ACRS – Advisory Committee on Reactor Safeguards**
- **AOP – Abnormal Operating Procedure**
- **ASLB – Atomic Safety & Licensing Board**
- **CFR – Code of Federal Regulations**
- **COL – Combined License**
- **COLA – Combined License Application**
- **CRE – Control Room Envelope**
- **DC – Design Certification**
- **EAB – Exclusion Area Boundary**
- **EOP – Emergency Operating Procedure**
- **FSAR – Final Safety Analysis Report**
- **GDC – General Design Criteria**
- **HFE – Human Factors Engineering**
- **HPM – Human Performance Monitoring**
- **I&C – Instrumentation and Controls**
- **LPZ – Low Population Zone**
- **MSLB – Main Steam Line Break**
- **PAM – Post Accident Monitoring**
- **PRA – Probability Risk Assessment**
- **RAI – Request for Additional Information**
- **RCP – Reactor Coolant Pump**
- **SER – Safety Evaluation Report**
- **SGTR – Steam Generator Tube Rupture**
- **TEDE – Total Effective Dose Equivalent**
- **UHS – Ultimate Heat Sink**



# **Spent Fuel Pool (SFP) Scoping Study**

Katie Wagner  
General Engineer  
Office of Nuclear Regulatory Research

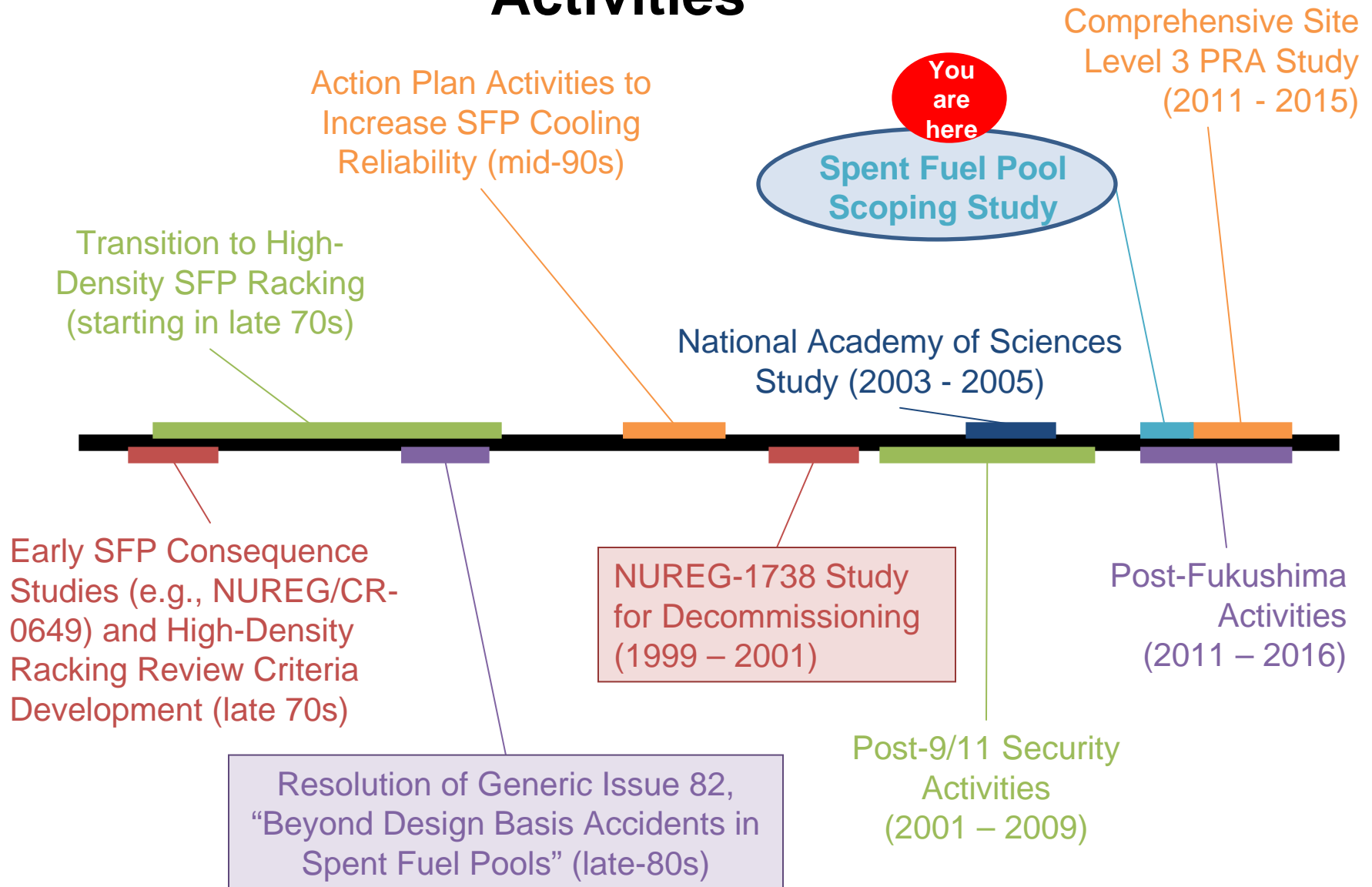
Briefing for the Advisory Committee on Reactor Safeguards  
(ACRS)

*April 12, 2012*

# Background

- The agency has a rich regulatory basis for its current position on spent fuel storage
- A number of events (e.g., change in path forward on long-term storage; Fukushima accident) motivated re-assessment of the underlying knowledge base
- To launch this re-assessment, an expedited limited-scope consequence study was undertaken (to provide insights in 1 year)
  - Objective: to re-examine the impact of moving older spent fuel to dry cask storage in an expedited manner
- Results from this study will inform a regulatory decision-making process guided by the “Tier 3” Japan Lessons-Learned item entitled Transfer of Spent Fuel to Dry Cask Storage (referenced in SECY-12-0025)

# Timeline of Major SFP-related Activities





# Motivation for Focusing on SFP Seismic Hazards

Spent fuel storage considerations include:

- SFP Seismic Hazards
- Dry Cask Storage Risk (e.g., NUREG-1864)
- Cask Drop Hazards for SFPs (e.g., NUREG-1738)
- Repackaging For Transportation
- Fuel Storage Infrastructure (e.g., 2010 EPRI study)
- Worker Dose (e.g., 2010 EPRI study)
- Emergency Preparedness (e.g., NUREG-1738)
- Part 50, 72 & 73 Regulatory Requirements
- Multi-Unit Risk (e.g., SECY-11-0089 project)
- Design/Operation Differences Between Sites
- Boraflex Degradation & Inadvertent Criticality
- Protection Against Malevolent Acts (e.g., post-9/11 security assessments)
- Other SFP Hazards (e.g., NUREG-1353)
- Actions in Response to Japan Events (e.g., Near-Term Task Force Recommendation 7)



**SFP  
Seismic  
Hazard**

*Past studies have indicated that SFP seismic hazard is an important piece of overall spent fuel risk.*

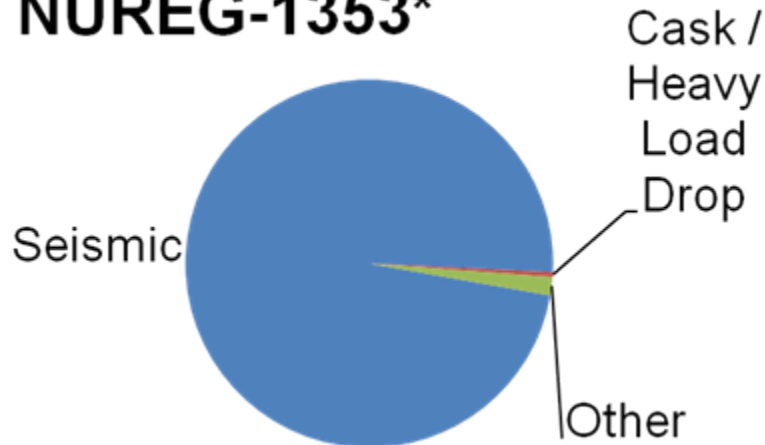
*For this reason, SFP seismic hazard is the logical place to start in probing the continued applicability of past studies and developing insights for the current spent fuel storage situation.*

*Depending on the results gained from the study, additional work might be necessary to obtain a more holistic answer.*

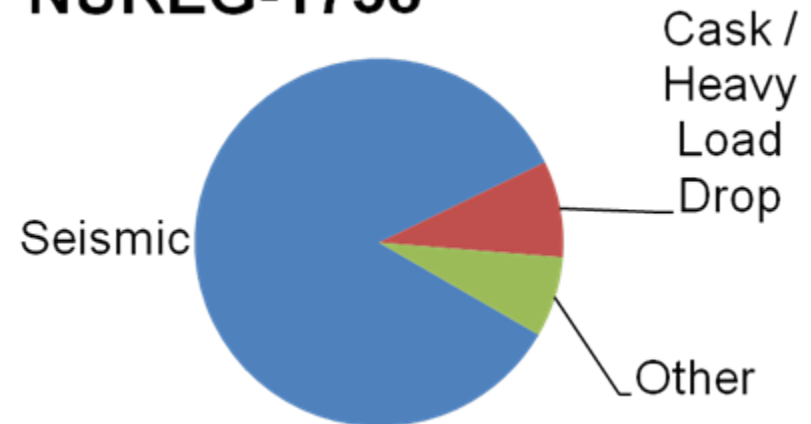
# Motivation for Seismic Study

Annual frequency of SFP fuel uncover as reported in previous SFP risk studies

**NUREG-1353\***



**NUREG-1738\*\***



\*BWR, best estimate results

\*\*Based on Livermore hazard curves which generally more closely match the updated USGS curves for the studied plant

Past SFP risk studies indicate that seismic hazard is the most prominent contributor to SFP fuel uncover. While these studies have known limitations, this is sufficient motivation to focus on this class of hazards in the SFPSS.

# Overview of Spent Fuel Pool Scoping Study (SFPSS)

- Focus: re-examine the potential impacts on SFP safety in the event of a challenging, beyond-design-basis seismic event
- Emphasis is given to acquiring timely results for ongoing deliberations and external stakeholder interest. The project is using:
  - Available information / methods
  - A representative operating cycle for a BWR Mark I (Peach Bottom)
  - Past studies to narrow scope
- Plan finalized in July 2011; study results to be sent to NRR: June 2012
- The closely related Japan Lessons Learned Tier 3 item from SECY-12-0025 (Transfer of Spent Fuel to Dry Cask Storage) addresses the bigger picture, with SFPSS being a key component

# Technical Approach

- Two conditions to be considered:
  - Representative of the current situation for the selected site (i.e., high-density loading and a relatively full SFP)
  - Representative of expedited movement of older fuel to a dry cask storage facility (i.e., low-density loading)
- Elements of the study include
  - Seismic and structural assessments based on available information to define initial and boundary conditions
  - SCALE analysis of reactor building dose rates
  - MELCOR accident progression analysis (effectiveness of mitigation, fission product release, etc.)
  - Emergency planning assessment
  - MACCS2 offsite consequence analysis (land contamination and health effects)
  - Probabilistic considerations

# **Seismic and Structural Methods**

*Jose Pires*

Senior Structural Engineer  
Office of Nuclear Regulatory  
Research

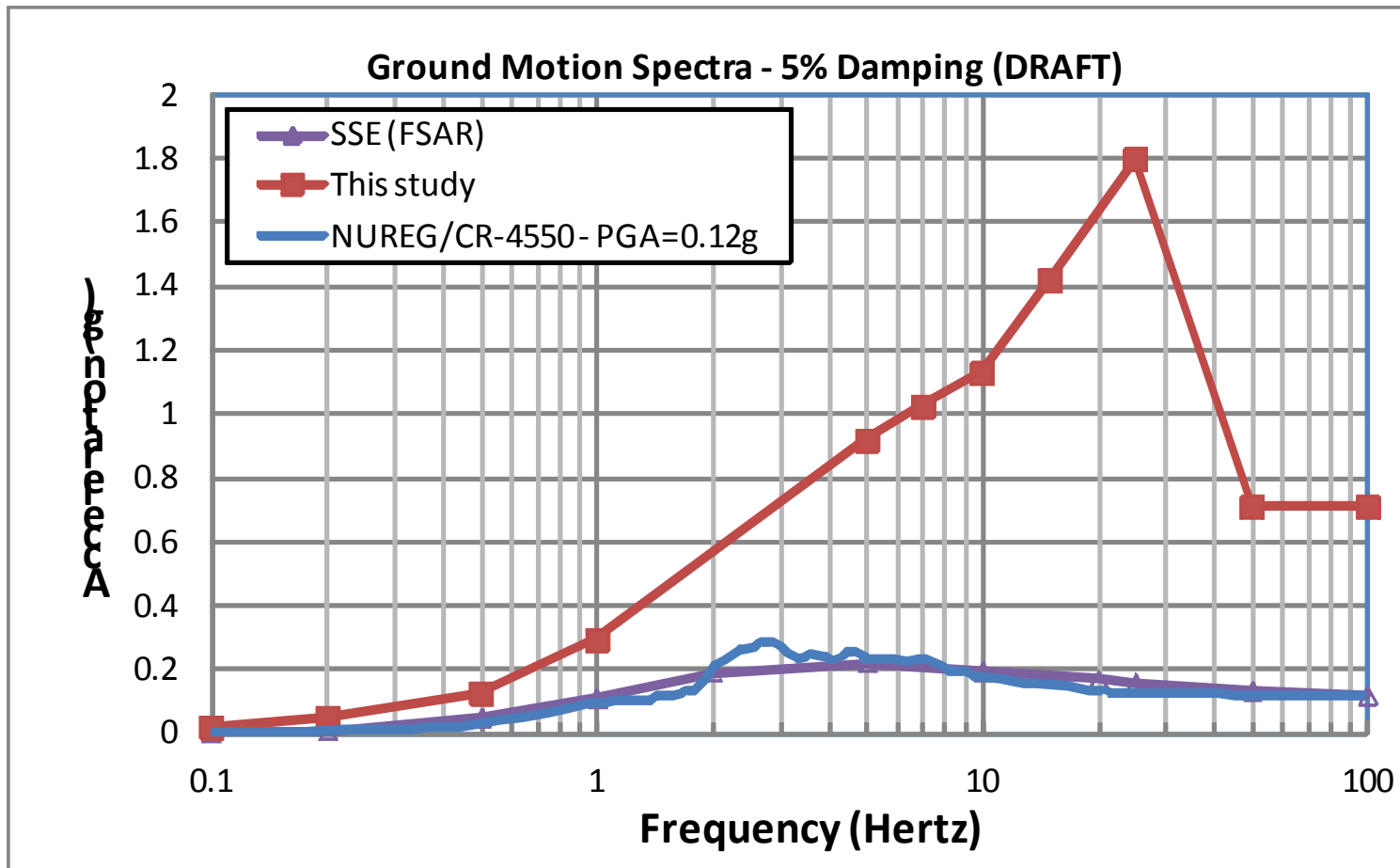
# Prescribed Seismic Scenario

- Seismic event: 0.5 g to 1.0 g peak ground acceleration (PGA)
  - Challenging event, but very low frequency of occurrence (one event in 61,000 years)
    - OBE is 0.05g
    - SSE is 0.12g
    - Scenario PGA is 0.71 g -- It is about 6 times that for the SSE and beyond the seismic design basis for Eastern US plants
  - USGS hazard data and models (2008) being used as starting seismic hazard model
- Review of past studies indicates that less severe events would not challenge the SFP

# Seismic Input

- Objective: to provide initial ground motion characteristics
  - Site Ground Motion Response Spectrum (GMRS)
- Rock site
- USGS Hazard Assessments (2008) used to obtain site GMRS (Similar to GI-199 resolution)
  - Site GMRS scaled up to obtain input ground motion spectra for the 0.71 g scenario
- Site GMRS rich in high frequencies (10 to 25 Hz)

# Seismic Input



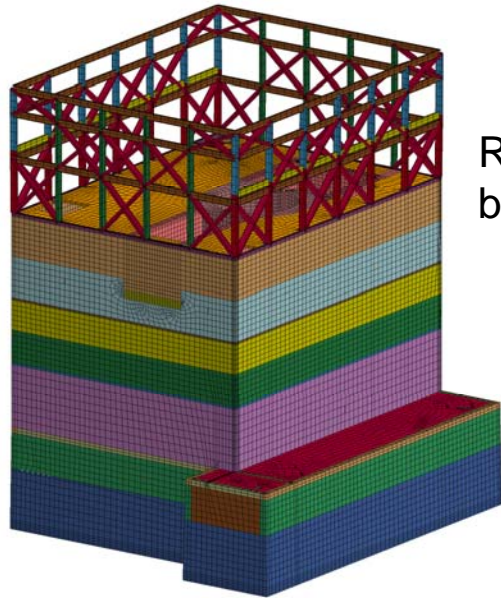
Comparison of ground motion spectra: this study, SSE, and spectrum for the NUREG-1150 PRA (scaled to the SSE PGA) (NUREG/CR-4550)



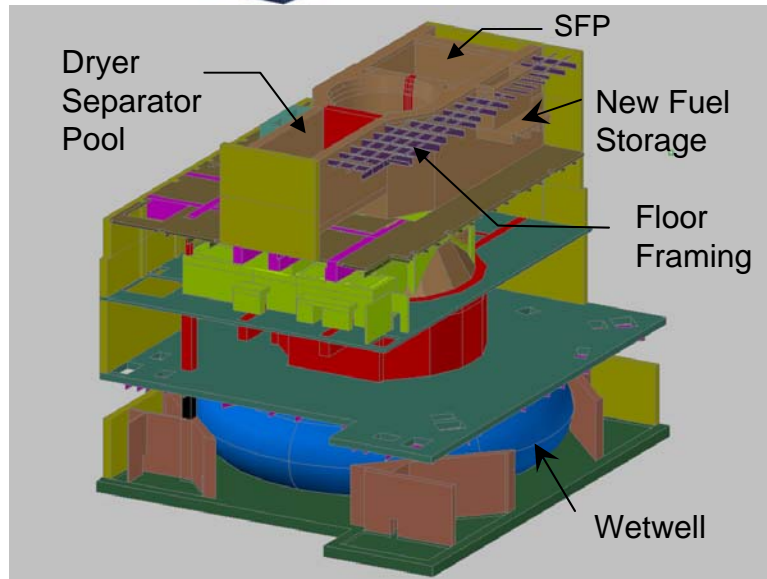
# Structural Input

- Objective: to determine starting point for subsequent accident progression analysis
- Approach:
  - Generally follows approach used for GI-82 (NUREG/CR-5176)
    - Enhanced to address specific study aspects (Finite Element Modeling)
  - Uses in-structure response spectra (accelerations) calculated for the NUREG-1150 study (NUREG/CR-4550, Vol. 4, Part 3)
    - Scaled for increased PGA (from 3xSSE to about 6xSSE)
    - Scaled to account for high frequency content in the site GMRS
  - Uses 3D nonlinear finite element analysis of the SFP structure and its supports (subjected to equivalent static loads) to calculate:
    - Displacements, concrete and reinforcement strains and stresses, structural distortion, and liner strains

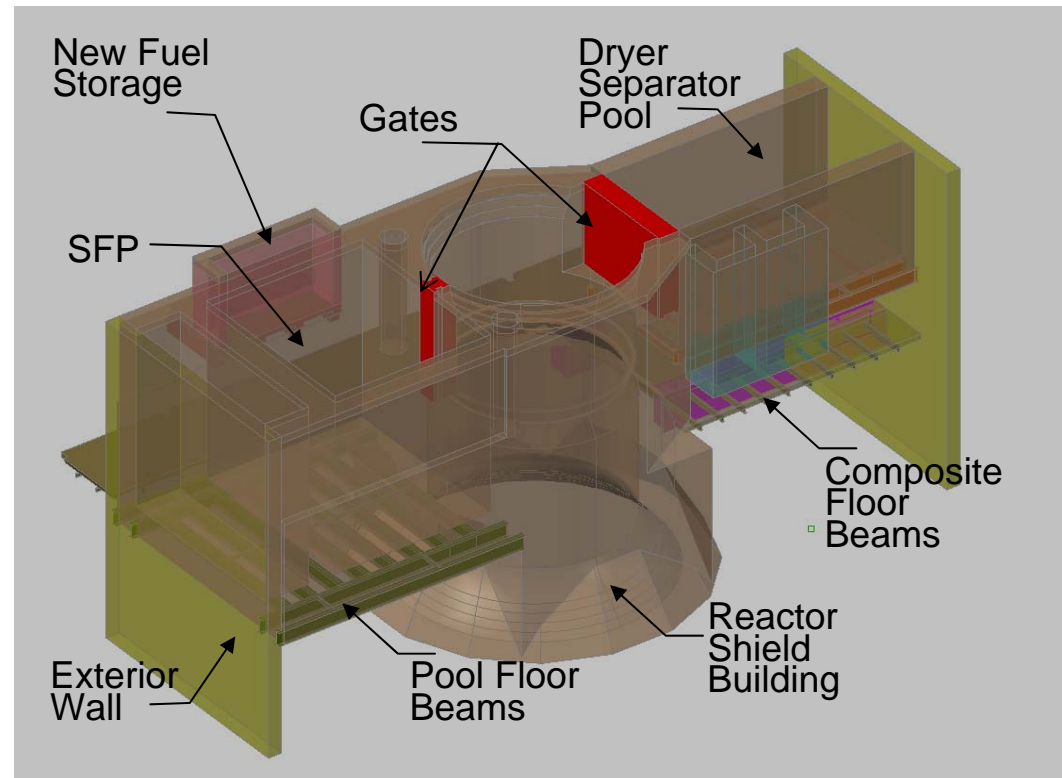
# Reactor Building and SFP



Reactor building



## SFP Details



**Used to generate 3D finite element models of the SFP structure and its supports**

# Structural Input

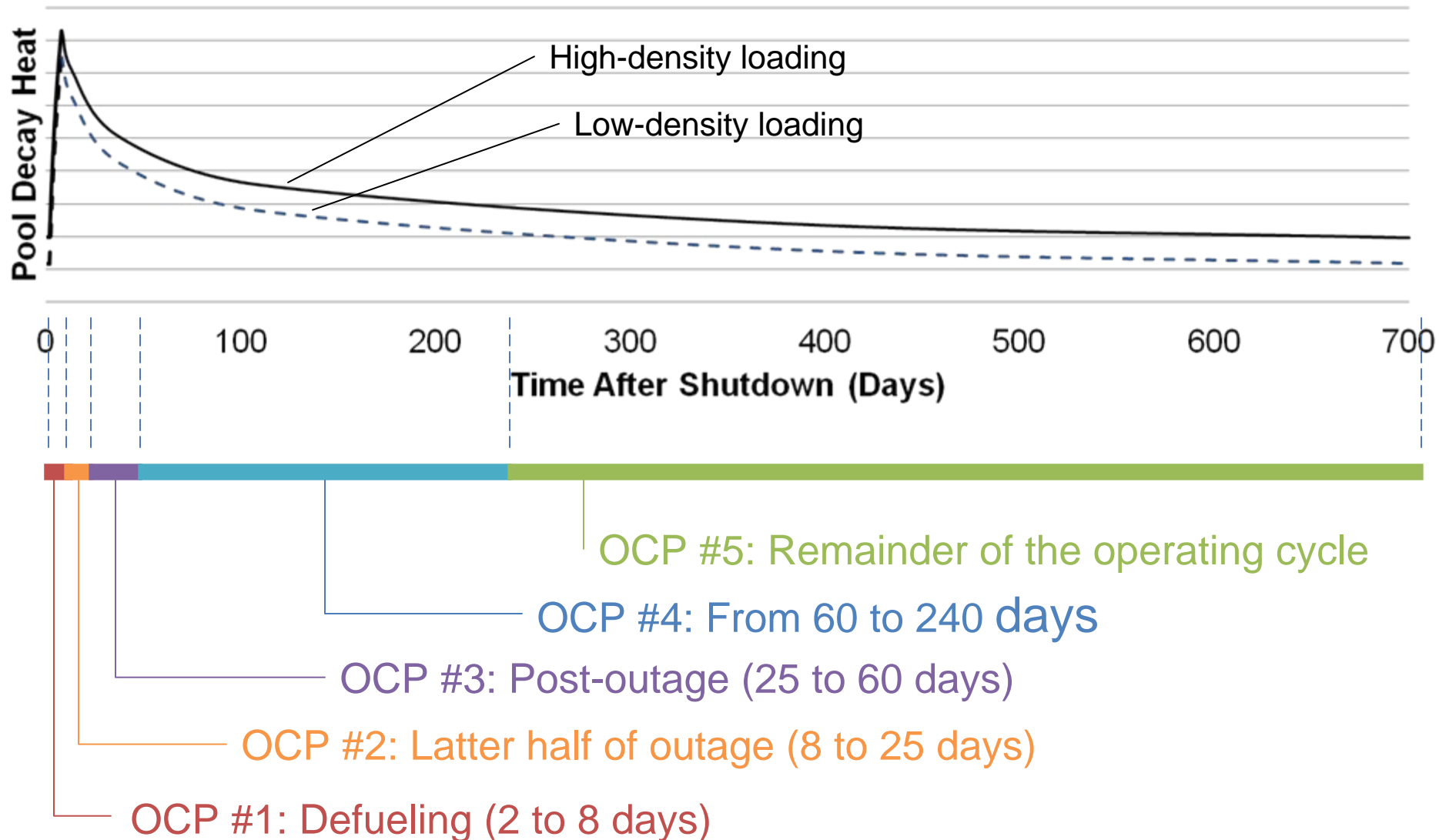
- Simpler approaches to assess damage to:
  - Penetrations, support systems, AC and DC power, other SSCs necessary for accident mitigation (e.g., building housing a portable diesel pump), other structures
- Approximations / assumptions
  - Effects of ground motion incoherency on high-frequency components of floor spectra approximated (possible conservatism)
  - Floor spectra do not account for coupling of SFP components to building (possible conservatism)
    - Hydrodynamic pressures based on scaled floor response spectra
    - Dynamic time-history analyses of the whole reactor building including the SFP were not done at this stage
  - Seismic loads from spent fuel racks and assemblies approximated
    - May need adjustment based on the analysis reports submitted by the licensee at the time of the license amendment for high density loading
  - Uses the SFP damage state to envelope potential leakage from the transfer gate, reactor piping, or dryer pool
- Starting conditions for accident progression analysis
  - Binned into a few discrete states with relative likelihood estimates

# **Scenario Delineation, Accident Progression Methods, and Consequence Analysis Methods**

*Don Helton*

Senior Risk and Reliability Engineer  
Office of Nuclear Regulatory  
Research

# Illustration of Pool Decay Heat and Operating Cycle Phases (OCPs)



# Mitigation Assumptions

- For high-density loading, two alternatives are considered for required arranging of recently discharged fuel in to a pattern that facilitate passive cooling:
  - pre-arrangement
  - arrangement following the outage
- For scenarios not including mitigative actions:
  - No operator action is considered
- For scenarios including mitigative actions:
  - Diagnosis is assumed to take until SFP level drops 5 feet + 30 minutes for observation/decision-making (recall unavailability of AC power)
  - Capacities / timings generally follow underlying endorsed guidance in NEI-06-12, Revision 2
  - Once deployed, equipment runs indefinitely
    - Represents successful arrival of offsite support or deployment of other onsite assets
- Effectiveness is determined by MELCOR

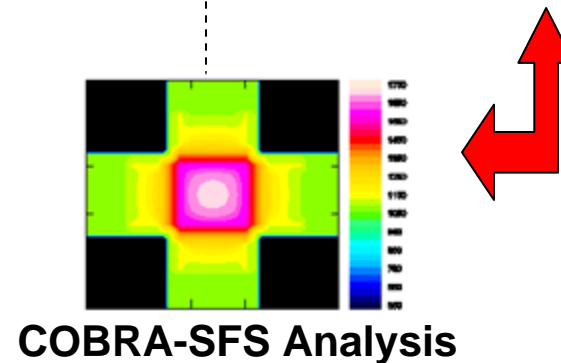
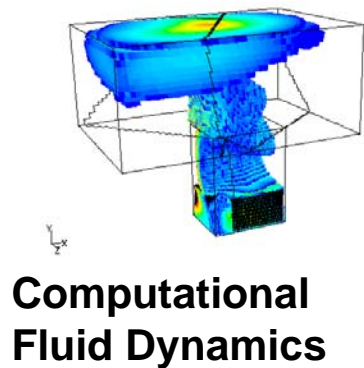
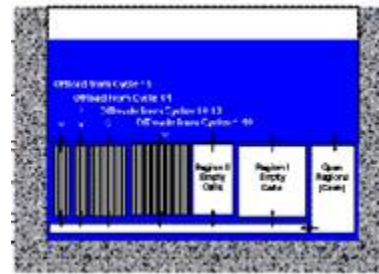
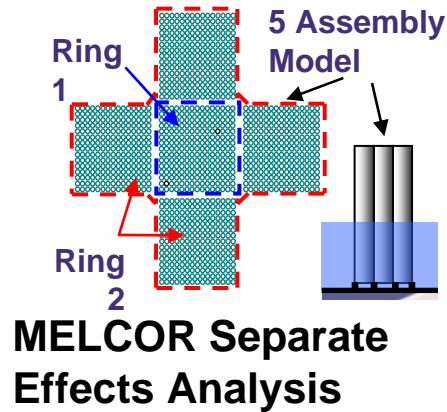
## Other Issues Not Addressed in Defining Scenarios

- Full core offload outages for vessel inspections
    - Not the typical situation for BWRs
  - Presence of new fuel in the SFP as source of zirconium
    - Present for a short period of time
  - Multi-unit effects
    - Only addressed until reactor/SFP become hydraulically decoupled
    - A focus of a recently initiated site Level 3 PRA project
  - Inadvertent criticality events
  - Recovery and repair actions
- The intent is to address as many uncertainties as practical via sensitivity studies



# Use of MELCOR for SFP Analysis

## Analysis

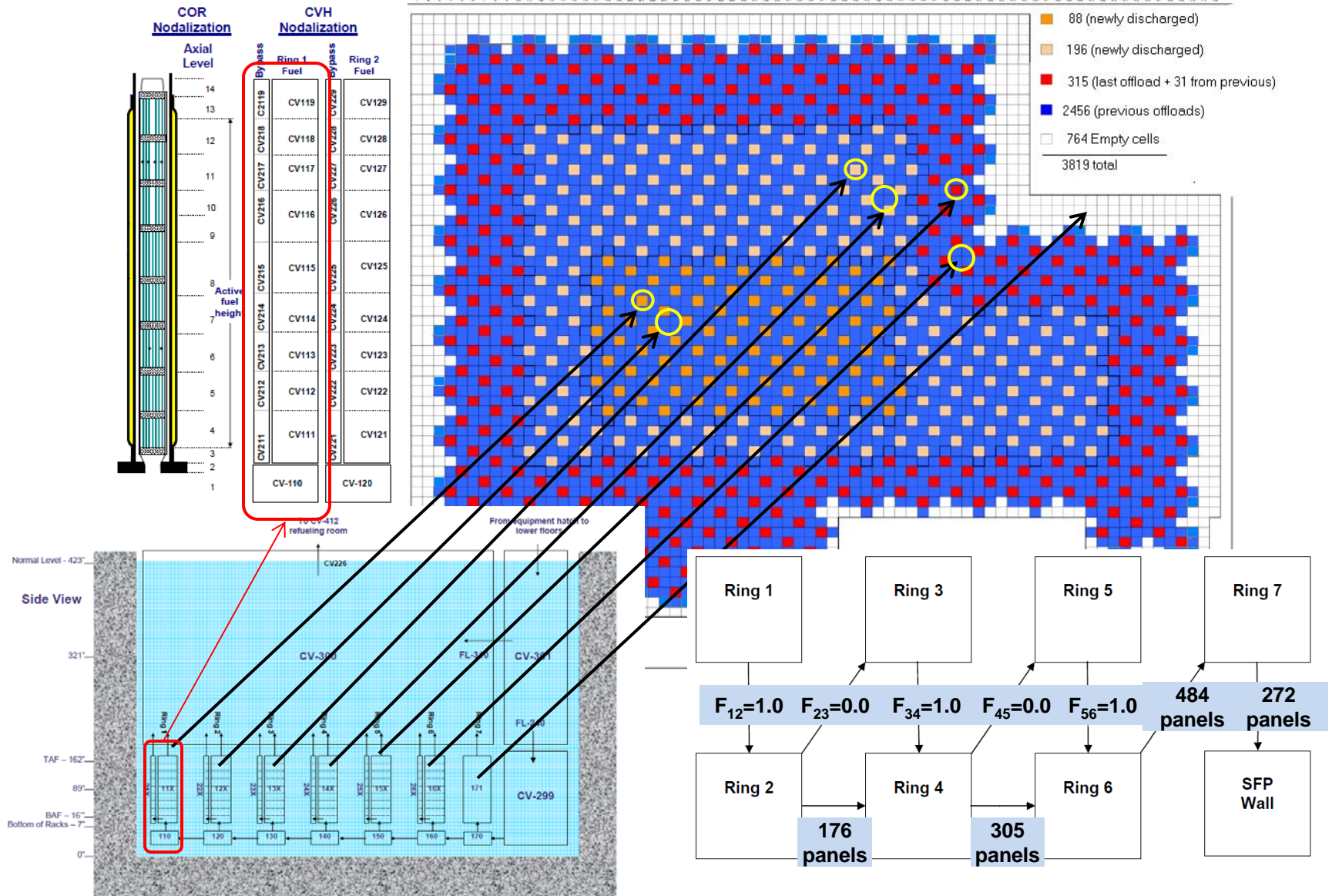


## Experimental studies

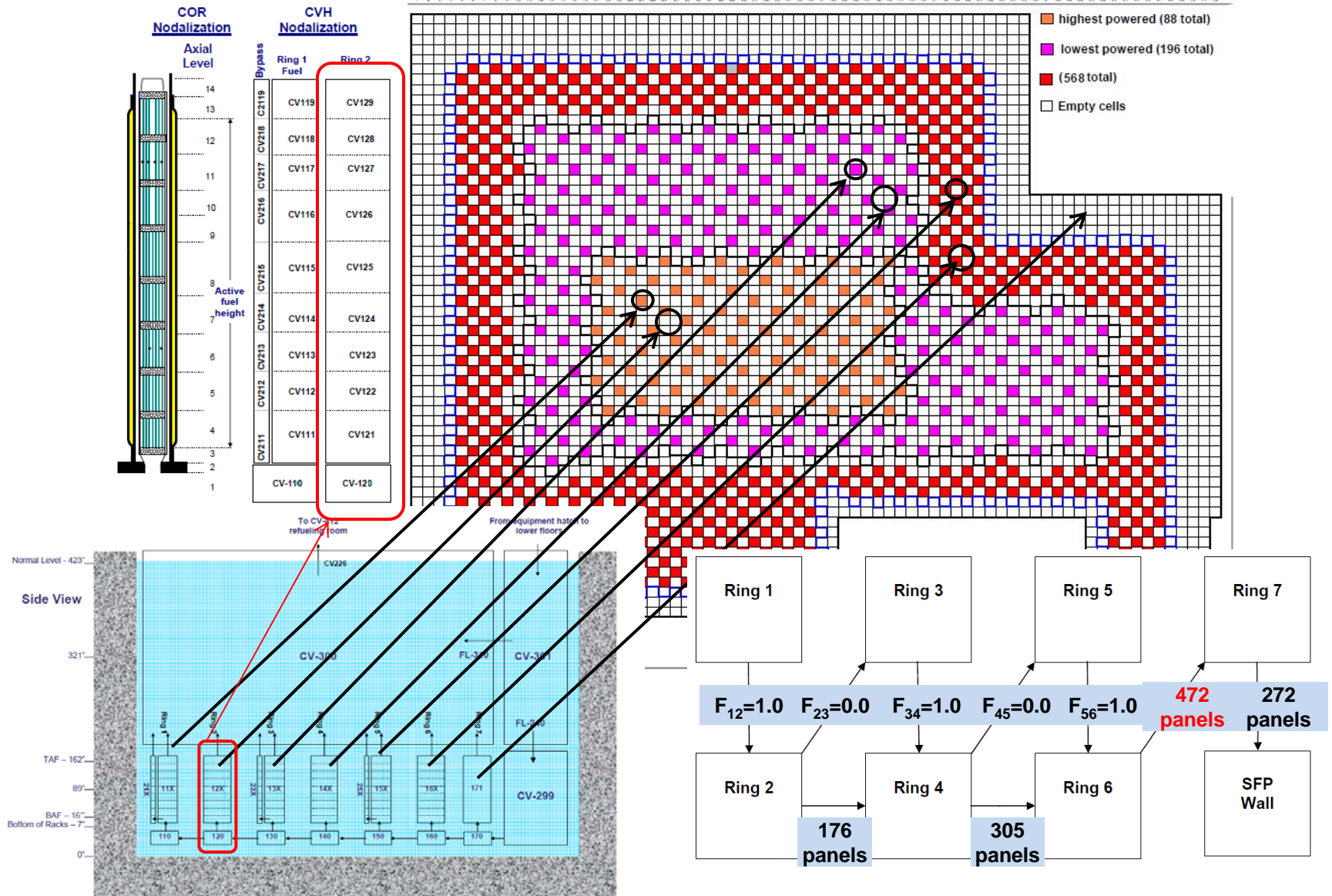




# High-Density Post-Outage SFP MELCOR Model



# Low-Density Post-Outage SFP MELCOR Model



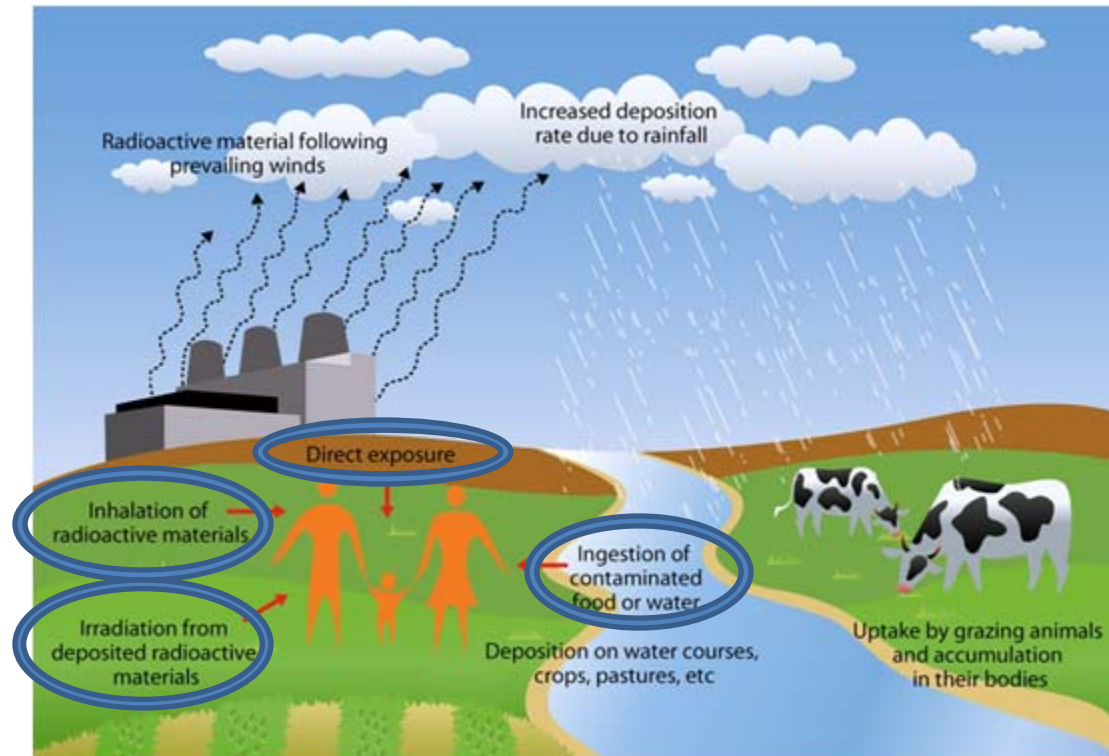
## Offsite Consequence & Emergency Preparedness Modeling

- MACCS2 code will be used
  - Input: Accident source term (from MELCOR/ORIGEN), weather, population and economic data, protective measures
  - Output: Consequences (e.g. contamination, health effects) from atmospheric release
- Modeling will leverage best practices from draft NUREG-1935 (SOARCA)
- Population and economic data updated for 2011
- Emergency preparedness considerations
  - Pennsylvania specific evacuation
  - Cohorts to represent different groups of the public
  - Road network
  - Scenario-specific



# MACCS2 Modeling: Atmospheric Release and Exposure Pathways

MACCS2 models the radioactive release to the atmosphere (e.g. plume rise, dispersion, dry and wet deposition)



MACCS2 estimates the health effects from: inhalation, cloudshine, groundshine, skin deposition, and ingestion (e.g. water, milk, meat, crops)

# Consequence Modeling & Reporting

- Consequence Modeling (continued):
  - Stochastic health effects (e.g. latent cancer fatalities)
  - Three dose response models
    - Linear, no threshold (LNT) hypothesis
    - Linear, low-dose truncation - 620 mrem/yr (U.S. average dose)
    - Linear, low-dose truncation - 5 rem/yr or 10 rem lifetime (HPS position)
  - Deterministic health effects (e.g. early fatalities)
  - Federal Guidance Report 13
    - Most current federal guidance published by EPA
- Consequence Reporting:
  - Health Effects - conditional risk of early fatalities and latent cancer fatalities as related to distance from the site. (Ideal for informing individual members of the public)
  - Land Contamination - total land contamination for the site region above a specified dose level (e.g., the habitability criterion for the selected site of 500 mrem/year)

# **Concluding Remarks and Questions**

*Katie Wagner*

# Coordination and Communication

- SECY paper to be submitted in July 2012 will include a plan for the resolution of the broader item on expedited transfer of spent fuel to dry cask storage
  - Commitment was made in SECY-12-0025
- Input from program offices
- Briefings for Senior Management and Commissioners
- Interactions with licensee
- Consider feedback provided by the ACRS
- A communication plan has been drafted
- Study results to be sent to NRR by: June 2012

# **SFPSS Project Team and Other-Office Working Group Representatives**

- Katie Wagner – Overall project lead
- Hossein Esmaili – Accident progression lead
- Don Helton – Boundary conditions and probabilistic aspects lead
- Andy Murphy – Seismic analysis lead
- AJ Nosek – Offsite consequence lead
- Jose Pires – Structural analysis lead

## **Working Group Members**

- NMSS – Drew Barto
- NRO – Eric Powell, Bret Tegeler
- NRR – Steve Jones, Jeff Mitman, Eric Bowman, Kent Wood, Rick Ennis
- NSIR – Randy Sullivan, Eric Schrader

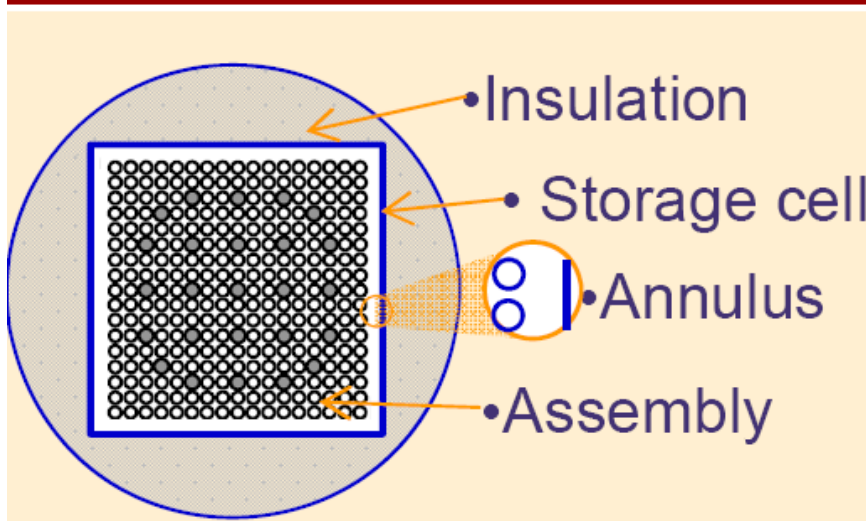


# Acronym List

- 3D = Three-Dimensional
- AC = Alternating Current
- BWR = Boiling Water Reactor
- COBRA-SFS = COBRA Spent Fuel Storage
- DC = Direct Current
- GI = Generic Issue
- GMRS = Ground Motion Response Spectra
- HPS = Health Physics Society
- LNT = Linear No Threshold
- MACCS2 = MELCOR Accident Consequence Code System
- MELCOR – Not an acronym
- NMSS = Office of Nuclear Material Safety and Safeguards
- NRO = Office of New Reactors
- NRR = Office of Nuclear Reactor Regulation
- NSIR = Office of Nuclear Security and Incident Response
- OBE = Operating Basis Earthquake
- OCP = Operating Cycle Phase
- ORIGIN = Oak Ridge Isotope Generator
- PGA = Peak Ground Acceleration
- PRA = Probabilistic Risk Assessment
- SCALE – Not an acronym
- SECY = Office of the Secretary
- SFP = Spent Fuel Pool
- SOARCA = State-Of-The-Art Reactor Consequence Analysis
- SSC = Structure, System and Component
- SSE = Safe Shutdown Earthquake
- USGS = United States Geological Survey

# SFP Zirc-Fire Research Overview

## Phase 1 Testing



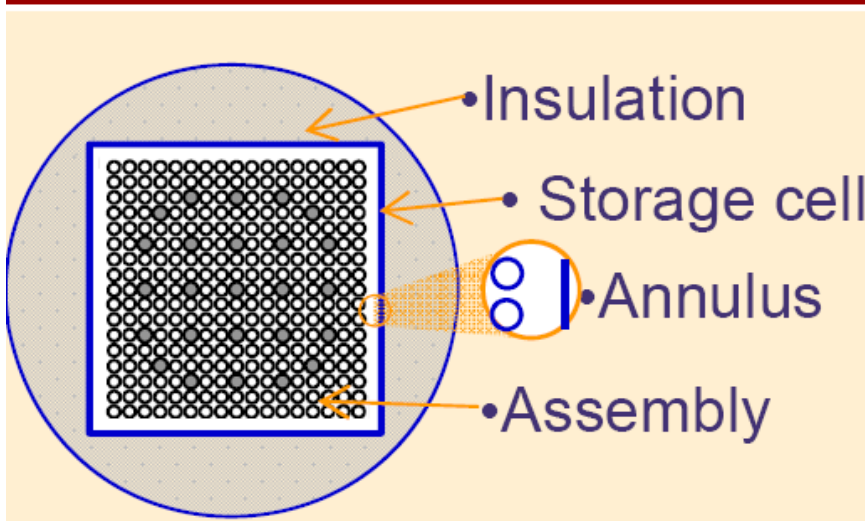
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**In promoting the denial of PRM-50-76 on June 29, 2005, ML050250359, the NRC Staff asserted:**

*According to him (Robert H. Leyse), it is fundamentally important that the determinations of LOCA transient chemical kinetics include the geometry of the stationary Zircaloy reactant in combination with the thermal-hydraulic conditions of the flowing-water/steam reactant.*

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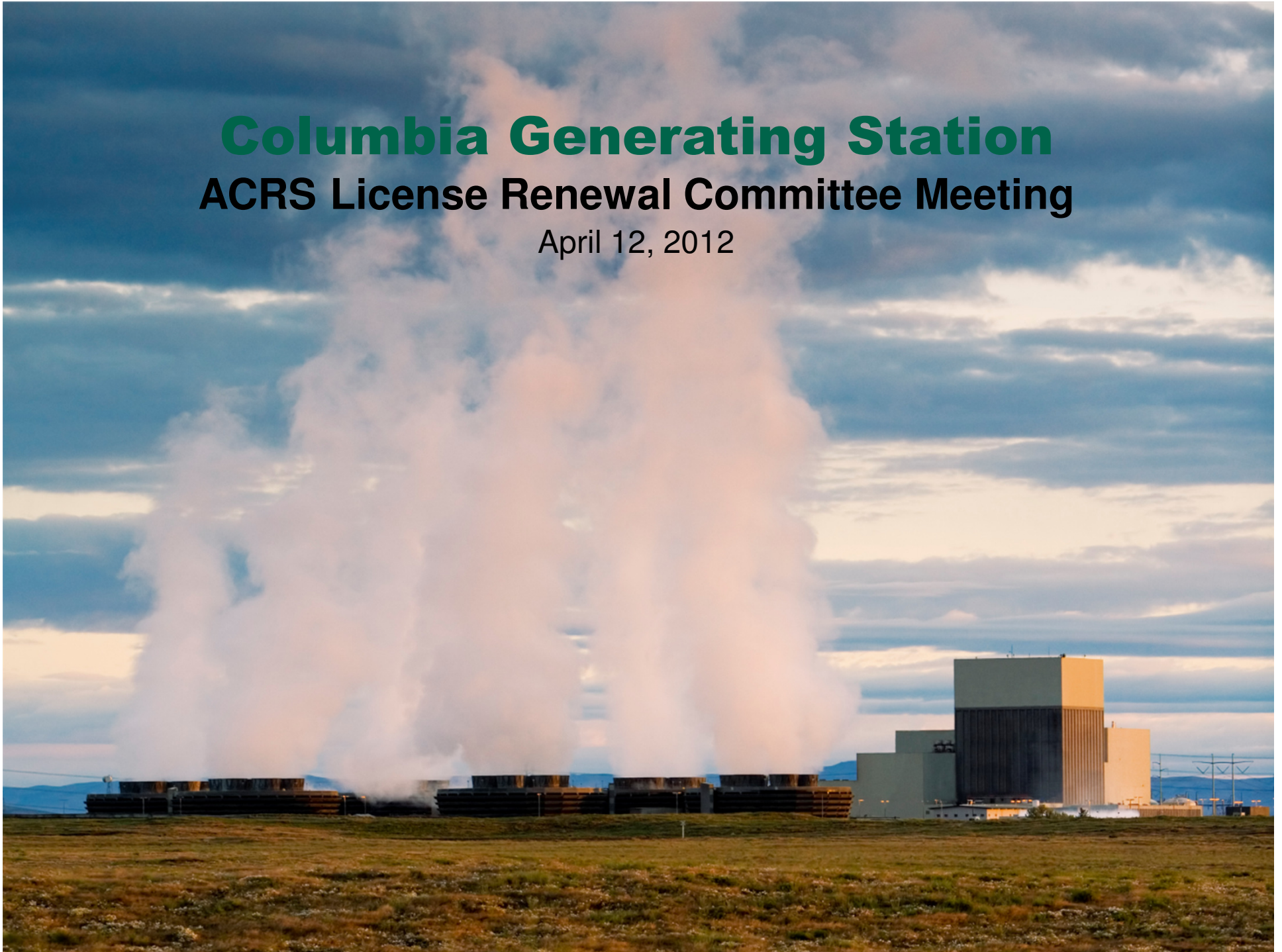
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# **Columbia Generating Station**

## **ACRS License Renewal Committee Meeting**

April 12, 2012



# Columbia Generating Station

**Dale Atkinson - Vice President, Emp Dev/Corp Services**

**Don Gregoire - Manager, Regulatory Affairs**

**John Twomey - Project Manager, License Renewal**

# Agenda

- Station Overview
- Aging Management Programs and Commitments
- Closure of Open Items
- Subcommittee Topics Requiring Additional Information
- Implementation Overview
- Closing Remarks





# Station Overview - Description

- General Electric Boiling Water Reactor
  - BWR-5 / Mark II Containment
  - Plant circulating water & ultimate heat sink makeup supplied from the Columbia River
- 3486 MWt/1230 MWe



# Station Overview - History

- Construction Permit – March 19, 1973
- Operating License – December 20, 1983
- 5% Power Up-Rate - May 1995
- License Renewal application submitted-Jan. 2010
- License Expires – December 20, 2023

# **Aging Management Programs and Commitments**

**Don Gregoire**  
**Manager, Regulatory Affairs**

# Aging Management Programs & Commitments

- Aging Management Programs (AMP)
  - 55 Programs Credited for License Renewal
    - 35 Existing
      - 13 Enhancements
    - 20 New
- License Renewal Commitments – 71 total

# Closure of Open Items

- High-Voltage Porcelain Insulators
- Operating Experience
- Upper-Shelf Energy
- Metal Fatigue
- Core Plate Rim Hold-Down Bolts
- Fatigue Analysis of Polar Crane

# Closure of Open Items

- OI 3.0.3.3.7

## High-Voltage Porcelain Insulators

230 kV Station Blackout recovery source insulators at Ashe substation were not included in the Insulator Aging Management Program

### Resolution

- Insulators are now in program
- Tests performed in July 2011 conclude minimal accumulation and within industry limits
- Testing on 8 year frequency consistent with operating experience

# Closure of Open Items

- OI B.1.4-1

## **Operating Experience (OE)**

Future operating experience evaluations for aging effects were not specifically included in the License Renewal Application (LRA)

### Resolution

- LRA amended to clearly call out intent to review internal and external OE on an on-going basis
- Operating Experience program revised to specifically address evaluation of OE for aging effects
- Initial/recurring training for plant staff

# Closure of Open Items

- OI 4.2-1

## Upper-Shelf Energy (USE)

Technical basis not provided for initial transverse USE and copper content for instrument nozzle forgings

### Resolution

- Technical basis was provided
- Supports acceptability through end of period of extended operation

# Closure of Open Items

- OI 4.3-1

## Metal Fatigue

Columbia's metal fatigue Time Limited Aging Analysis (TLAA) performed for sample of critical locations listed in NUREG/CR-6260 may not be limiting

### Resolution

- The other limiting locations were identified and evaluated for Columbia
- All locations have an environmental cumulative usage factor below 1.0



# Closure of Open Items

- OI 4.7.4-1

## Lower Core Plate Rim Hold-Down Bolts

Neither an Aging Management Review (AMR) line item nor a TLAA for the reactor pressure vessel lower core plate hold-down bolts were provided

### Resolution

- LRA was amended to include:
  - AMR line item for TLAA
  - TLAA disposition for 10 CFR 54.21(c)(1)(iii)

# Closure of Open Items

- OI 4.7.5-1

## Fatigue Analysis of Polar Crane

Columbia's LRA did not include TLAA for polar crane

### Resolution

- Columbia has an overhead crane but not a polar crane
- TLAA performed for all fifteen (15) in-scope cranes and hoists
- TLAA remains valid for the period of extended operation as per 10 CFR 54.21(c)(1)(i)

# Subcommittee Topics Requiring Additional Information

Following are topics for which additional information was provided to subcommittee in December 2011:

- Microbiologically Influenced Corrosion (MIC) in systems
- Metal-Enclosed Bus (MEB) catastrophic failure
- Makeup water line from river
- Scope of Plant Service Water (TSW) piping to Reactor Closed Cooling (RCC) system
- Internal inspection of raw water buried piping
- Additional long-term plans for copper reduction

# Implementation Overview

- Implementation Activities incorporated into Columbia's Long Range Plan
  - Implementation coordinator on staff
  - Implementation procedure in place
  - Development of remaining AMPs scheduled
  - Active participation in License Renewal Implementation Working Group
  - Benchmarking of other sites with renewed licenses

# Closing Remarks

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# Closing Remarks



# U.S.NRC

UNITED STATES NUCLEAR REGULATORY COMMISSION

*Protecting People and the Environment*

## **RISK-INFORMED REGULATORY FRAMEWORK FOR NEW REACTORS**

### **Advisory Committee on Reactor Safeguards**

Contacts: Don Dube, NRO/DSRA, 301-415-1483  
Ron Frahm, NRR/DIRS, 301-415-2986

**April 12, 2012**



# Meeting Purpose

**Discuss staff's response to the SRM  
on SECY-10-0121 and request a letter**

# Agenda

- **Brief background**
- **Tabletop exercise results**
  - **RITS 4b, completion times**
  - **Reactor oversight process**
- **Conclusions, options and recommendations in draft paper**

## **Options Provided in SECY-10-0121**

- 1) No changes to existing risk-informed guidance (status quo)**
- 2) Implement enhancements to existing guidance to prevent significant decrease in enhanced safety (NRC staff recommendation)**
- 3) Develop lower numeric thresholds for new reactors**

# **Commission SRM**

## **Dated March 2, 2011**

- **Commission approved a hybrid of Options 1 and 2**
  - Continue existing risk-informed framework pending a series of tabletop exercises that test existing guidance
- **Commission “reaffirms” existing**
  - safety goals
  - safety performance expectations
  - subsidiary risk goals and associated risk guidance
  - key principles (e.g., RG 1.174)
  - quantitative metrics
- **New reactors with enhanced margins and safety features should have greater operational flexibility than current reactors**

# Tabletop Exercises

- December 2, 2010: 50.59-like change process for ex-vessel severe accident (EVSA) design features under Section VIII.B.5.c of each design certification rule
- May 4, 2011: Risk-informed inservice inspection of piping
- May 26, 2011 and June 1, 2011: Risk-Informed Technical Specifications (RITS) Initiative 4b on completion times and the Maintenance Rule (a)(4)
- June 29, 2011: RITS Initiative 5b (surveillance frequency control program)
- August 9, 2011: 50.69 and guidance in NEI 96-07 Appendix C on the change processes for Part 52 specific to EVSA design features
- October 5, 2011: RG 1.174; transition options from large release frequency (LRF) as a risk metric to large early release frequency (LERF); and ROP risk-informed case studies including SDP, reactive inspections under Management Directive 8.3, and MSPI
- October 26, 2011: Follow-up discussions with stakeholders on the ROP

## Major Conclusions

- During the tabletop exercises for licensing applications, the staff did not identify any potentially significant decreases in the enhanced safety margins for new reactors
- Identified potential gap in the Tier 2 change process regarding severe accident features that are not related to ex-vessel severe accident prevention and mitigation
- Current risk thresholds are appropriate for ROP; however, a few changes to the ROP may be warranted consistent with the integrated risk-informed principles in RG 1.174

# Key Tabletop Exercise Results

- **RITS 4b (completion times): Two key programmatic controls**
  - The risk-informed completion time is limited to a deterministic maximum of 30 days (referred to as the backstop completion time) from the time the TS action was first entered
  - Voluntary use of the risk-managed TS for a configuration which represents a loss of TS specified safety function, or inoperability of all required safety trains, is not permitted

# AP1000: RITS 4b Case Study

<b>Class 1E DC System (IDS)</b>			
<b>Division A</b>	<b>Division B</b>	<b>Division C</b>	<b>Division D</b>
1 - 24hr Battery	1 - 24hr Battery	1 - 24hr Battery	1 - 24hr Battery
	1 - 72hr Battery	1 - 72hr Battery	

<b>Passive Core Cooling (PXS)</b>	
<b>DVI Line A</b>	<b>DVI Line B</b>
Accum.-A (CKV)	Accum.-B (CKV)
CMT-A (CKV)	CMT-B (CKV)
IRWST-A (MOV)	IRWST-B (MOV)
IRWST-A (CKV1)	IRWST-B (CKV1)
IRWST-A (CKV2)	IRWST-B (CKV2)



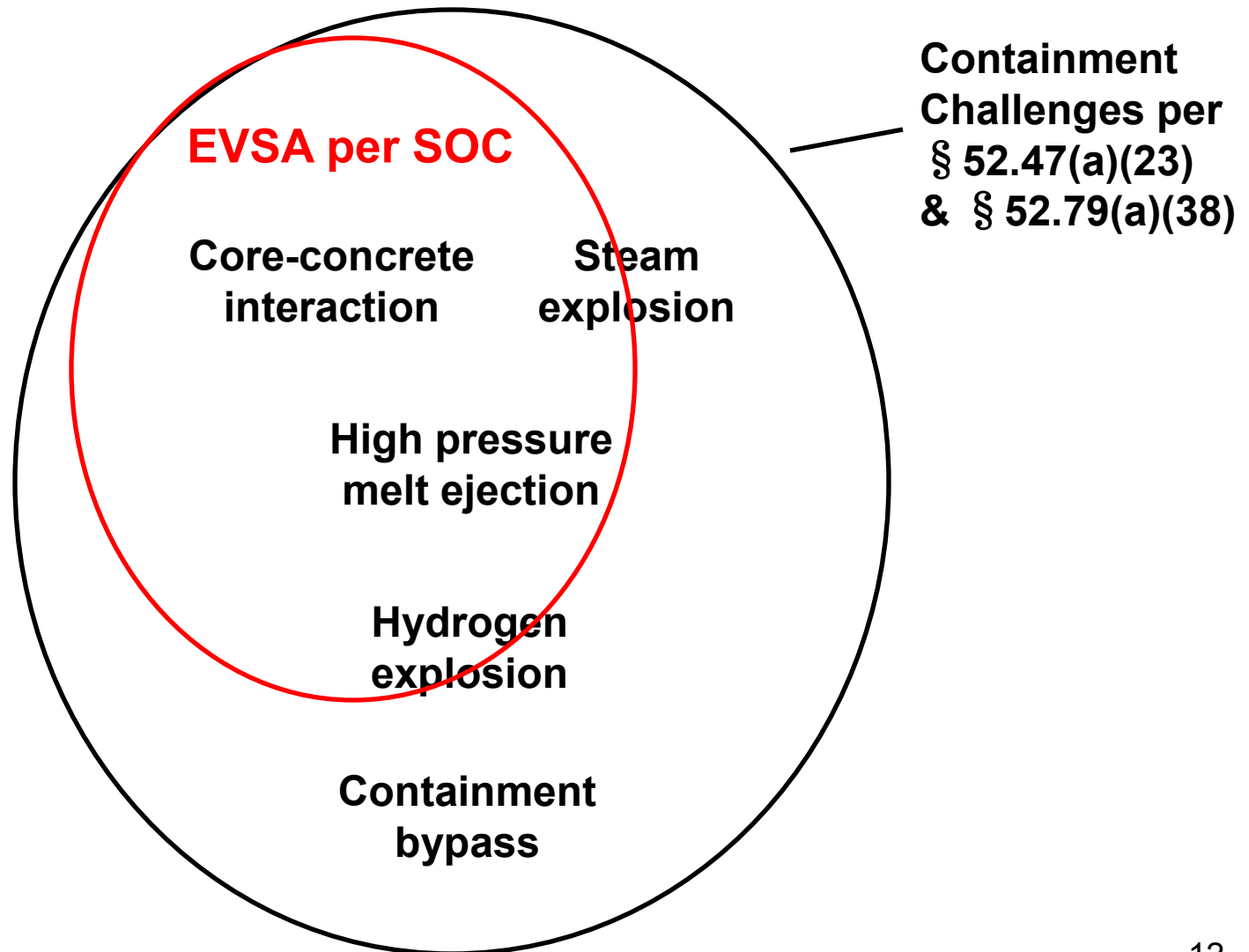
# AP1000 SPAR Model Results

RITS 4b Case	Equip. Not Functional	CDF (/yr)	$\Delta$ CDF (/yr)	Calc Completion Time (days)	Tech. Spec. Limit (hrs)	Allowed Completion Time (days)	ICDP	Other Available Equip
Base	None (no T&M)	2.1E-07	--	--	--	--	--	All
1	1 - 1E-DCP-A (DC/AC)	5.9E-07	3.8E-07	9623	6	30	3.1E-08	1 - 24hr division and 2 - 24/72hr divisions
7*	1 IRWST Injection Line-B	1.1E-04	1.1E-04	33	1	[1hr]	[1.3E-08]	2 Accum., 1 IRWST ILs (2 flow paths), 2 PHRHs flow paths, and 2 CMTs
9-A*	1 CMT-A and 1 Accum.-A	1.6E-04	1.5E-04	24	CMT - 1 Accum. - 1	[1hr]	[1.8E-08]	1 Accum., 2 IRWST ILs (4 flow paths), 2 PHRHs flow paths, and 1 CMT

## Key Tabletop Results (cont.)

- **RITS 4b staff exercises**
  - Staff identified some configurations of equipment outages that would represent 10 years' worth of core damage probability
  - Repeated entry into such condition over time could increase CDF by one or more orders of magnitude, which could approach the baseline CDF of currently operating plants
  - Staff believes these configurations are unlikely or unrealistic, and that there were additional regulatory and programmatic controls that would limit the aggregated risk increase (e.g., performance monitoring, periodic PRA maintenance and upgrade under 50.71(h))
- **Staff concludes no substantive changes to methodology is necessary**

## Tier 2 Change Process: Gap identified for ex-vessel severe accident features



## Key Tabletop Results (cont.)

### Recommendation 1

Address the potential gap, by a) ensuring that there are sufficient details on all key severe accident features in Tier 1, and b) including a change process in future design certification rulemakings in Section VIII for *non-ex-vessel severe accident features* similar to Section VIII.B.5.c for *ex-vessel severe accident features*

# LRF-to-LERF Transition

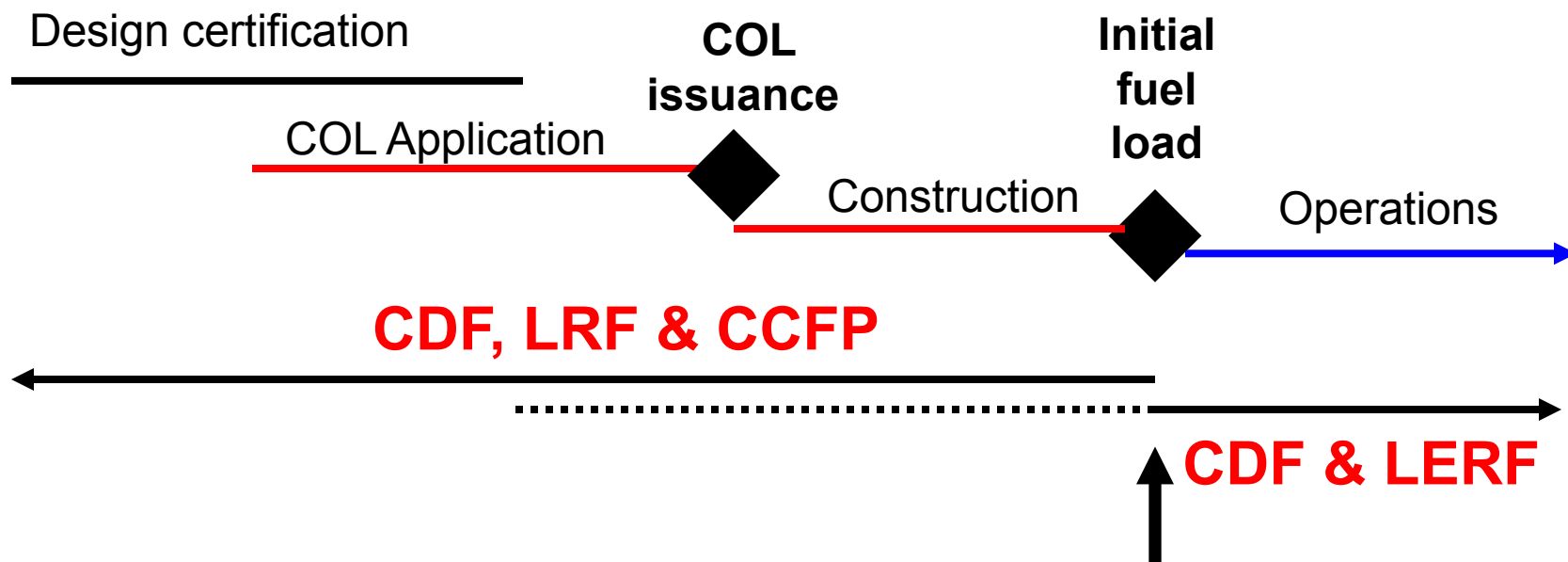
- **LRF vs. LERF**

- Commission goals for new reactors are based on a conditional containment failure probability (CCFP) of less than 0.1, and a LRF of less than  $10^{-6}$ /yr, as well as  $10^{-4}$ /yr for core damage frequency (CDF)
- Operating reactors use CDF and LERF as risk metrics

- **LRF issues**

- LRF (and CCFP) have not been defined by the staff
- Each design center has chosen different definitions
- LERF is used in the ASME/ANS level 1 PRA standard, in risk-informed staff guidance (e.g., RG 1.174), and ROP
- No existing or proposed level 2 PRA standard provides a universal definition of LRF

## Recommendation 2: Option 2C



- LERF calculated at or prior to initial fuel load. CDF & LERF used for RG 1.174 acceptance guidelines going forward.
- Last regulatory use of LRF & CCFP
- Continue to meet containment performance objective following core damage per SECY-90-016 and SECY-93-087

# Tabletop Results on Other Licensing and Operational Programs

- **50.65(a)(4) – no gaps**
  - Defense in depth and plant transient assessment often more limiting in terms of risk management action level
- **RITS 5b (surveillance frequency) – no gaps**
  - Much more deterministically oriented, with risk impact only a secondary consideration in the criteria for changing surveillance test interval
- **50.69 (SSC categorization) – no gaps**
  - Rule has built-in measures to monitor RISC-3 components and take corrective actions (e.g., periodic program review every 2 refuel cycles)
- **RG 1.174 – no gaps**
  - Considerations such as defense in depth and margin of safety often more limiting than risk impact

# ROP Tabletop Approach

- Tested various realistic scenarios to confirm the adequacy of the current ROP risk-informed processes for regulatory decision-making or identify areas for improvement
- Used a broad cross-section of well-vetted cases, developed from actual greater-than-green examples from the current fleet of reactors:
  - Significance Determination Process (SDP) findings
  - Mitigating Systems Performance Index (MSPI) data
  - Management Directive (MD) 8.3 applications
- Applied similar situations to the new reactor designs, filling in gaps with realistic hypothetical situations and reasonable assumptions, and then compared the risk values and resultant regulatory response



## RESULTS

- Existing risk thresholds for determining significance of inspection findings are generally acceptable
- Greater-than-green inspection findings would likely involve common cause failures and/or long exposures of risk-significant components
- Existing process does not always ensure an appropriate regulatory response for degradation of passive components and barriers

## CONCLUSION

- SDP analyses could be augmented with additional qualitative considerations (deterministic backstop) to appropriately address performance issues

## **MD 8.3 Tabletops**

### **RESULTS**

- Existing risk thresholds for invoking reactive inspections are adequate for new reactors
- Deterministic criteria used initially for event screening and then within a range of response determined by risk values
- Risk values heavily influence whether or not a reactive inspection is warranted and, if so, at what level
- Variations in or minor revisions to risk models used can potentially result in an inadequate response

### **CONCLUSION**

- Contribution of existing deterministic criteria could be modified or new deterministic criteria developed for initiating reactive inspections for new reactors

# MSPI Tabletops

## RESULTS

- Existing MSPI is not adequate and would be largely ineffective in determining an appropriate regulatory response for active new reactor designs
- Meaningful MSPI may not even be possible for passive systems using the current formulation of the indicator
- Existing performance limit (backstop) could be further leveraged for active new reactor designs

## CONCLUSION

- Alternate PIs in the mitigating systems cornerstone could be developed and/or additional inspection could be used to supplement insights currently gained through MSPI

# ROP Options

## OBJECTIVES FOR ROP OPTIONS

- Maintain current risk thresholds for new reactor designs
- Consistent with integrated risk-informed decision-making concepts in RG 1.174
- Afford greater operational flexibility based on enhanced safety margins

### A. USE AS IS

- Use the existing risk-informed ROP tools for new reactor applications without making any changes
- No additional action or resources needed, but existing tools may not always provide for an appropriate regulatory response

## ROP Options (cont.)

### **B. AUGMENT EXISTING PROCESSES**

- SDP: Use existing risk-informed SDP, but augment with deterministic backstops to ensure an appropriate regulatory response to address performance issues
- MD 8.3: Modify the contribution of existing deterministic criteria or develop new criteria for determining the appropriate regulatory response to plant events
- MSPI: Develop alternative to MSPI or augment existing guidance to emphasize performance limit for active new reactor designs, and increase inspection of passive mitigating systems for passive new reactor designs
- Proposed enhancements could be developed using existing resources and working with stakeholders

## **ROP Options (cont.)**

### **C. DEVELOP DETERMINISTIC TOOLS**

- Do not use the existing risk-informed ROP tools
- Capture risk insights to a lesser extent than the current fleet using deterministic guidance consistent with new reactor design certification and licensing basis
- Additional resources may be necessary to research and develop the new guidance documents

### **Staff Recommendation: Option B**

- Staff would obtain Commission approval for proposed changes to ROP at least one year prior to implementation
- Process enhancements could be further refined based on experience and lessons learned

## **Next steps**

- **Finalize Commission paper based on ACRS and stakeholder feedback**
- **SECY due to be issued early June, 2012**



**EPRI**

ELECTRIC POWER  
RESEARCH INSTITUTE



**SAIC**

# **EPRI/NRC-RES FIRE HRA GUIDELINES, NUREG-1921/EPRI 1023001**

Mark Henry Salley and Susan E. Cooper (NRC/RES/DRA)  
Stuart Lewis (EPRI)

ACRS Full Committee Meeting  
April 13, 2012  
Rockville, MD

*A Collaboration of U.S. NRC Office of Nuclear Regulatory Research (RES) & Electric Power Research Institute (EPRI)*

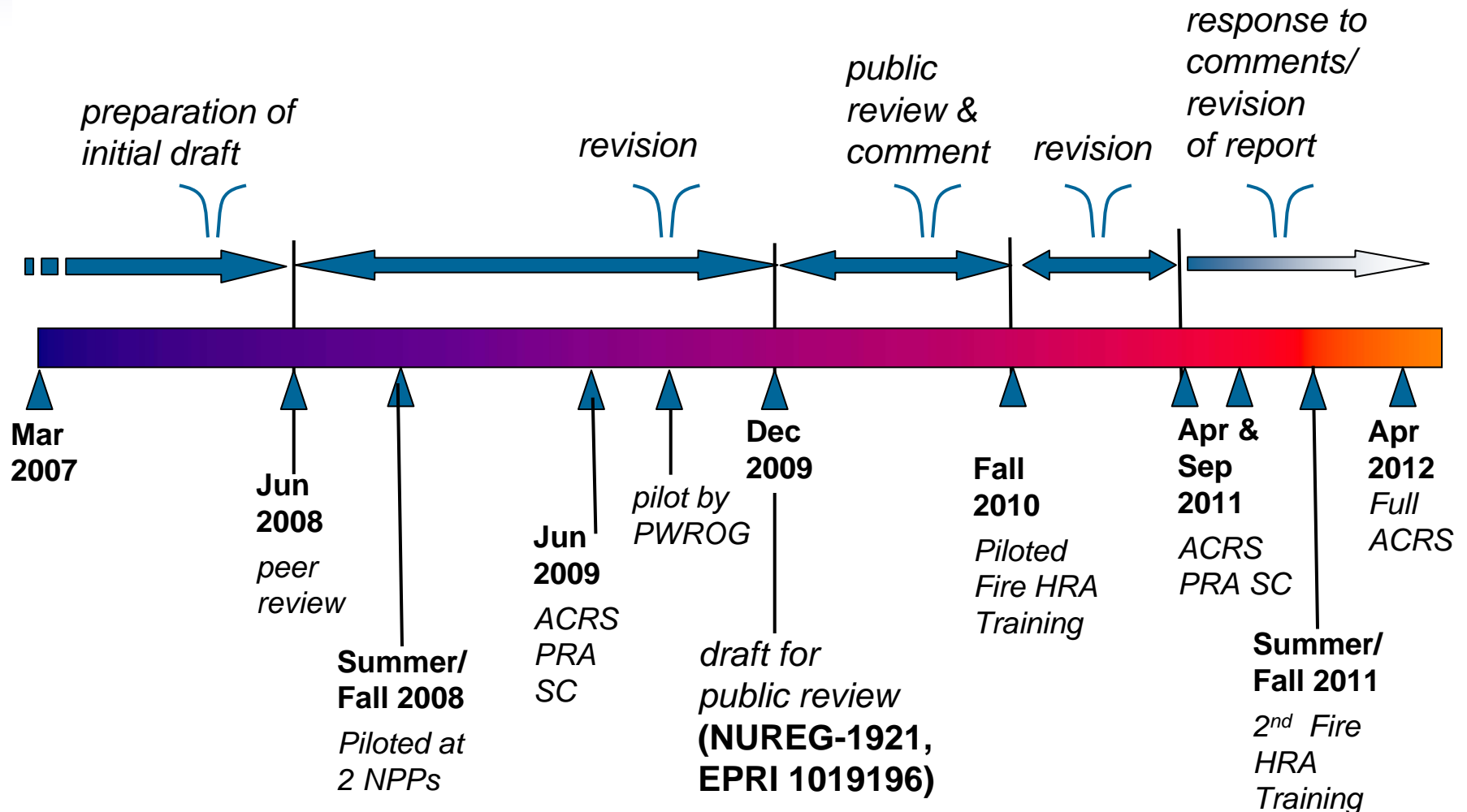


# Today's Presentation

- Short history and background of the project
- Project objectives
- Examples of challenges
- Industry perspective
- Review, Testing and Trial Applications
- Uses for other HRA projects

**Project Team requests letter from ACRS**

# Evolution of the Fire HRA Guidelines



# Background on Fire HRA

## Status of fire PRA at project initiation

- About half of US NPPs transitioning to NFPA-805
- NUREG/CR-6850 [EPRI 1011989] provided detailed guidance for fire PRA to support transition to NFPA-805

## HRA for fire PRA

- Guidance in NUREG/CR-6850
  - Conservative screening human error probabilities (HEPs)
  - Performance shaping factors (PSFs)
- Needs beyond NUREG/CR-6850
  - Approach for detailed/best-estimate HRA
  - Guidance to satisfy requirements in PRA Standard

# Objectives of Fire HRA Guidelines

- Address HRA needs beyond NUREG/CR-6850
  - Detailed quantification method for fire PRA context
  - Treatment of relevant PSFs
  - Steps to satisfy PRA Standard requirements
- Satisfy NRR User Need 2008-003, Rev. 1, Task 13
  - “...expand existing HRA methods ... to incorporate the effect of fires in full-power PRA models.”*

**Pursued via joint EPRI/NRC MOU analogous to NUREG/CR-6850  
(third major joint fire-related project)**

# Examples of challenges addressed

- Need for advances in state-of-the-art for fire HRA
  - Full delineation of HRA process for fire context
  - Feasibility of human actions
  - Guidance for:
    - Response to spurious signals/actuators from cable failures
    - Potential errors of commission (EOCs)
    - Distractions in control room
    - Uncertainties (e.g., for timing information)
  - Appropriate quantification methods
    - New scoping approach
    - Adaptation of (two) existing methods for detailed analysis
  - Implications for ex-control room actions

# Examples of challenges addressed (continued)

- Piloting of methods and guidance
- Guidance to meet evolving requirements in PRA Standard
- Evolving approaches to implementing fire PRA tasks
- Continuing improvements to fire procedures in plants
- Need to develop training material in parallel with report

# Industry Perspective

- Focus has been on
  - Assuring guidance meets technical needs of users
  - Ensuring adequate review, testing and trial application
- Important attributes of technical approach
  - Addresses range of fire response strategies in place at plants
  - Coordinates with development of actual fire PRA models
  - Capable of producing useful insights
  - Consistent with HRA for internal events

# Review, Testing and Trial Application

- Peer review (June 2008)
- Pilot applications
  - Scoping tested by project team at two NPPs (2008)
  - Pilot by PWR Owners Group (2009)
- Public review of full draft (early 2010)
- Applications
  - Use of draft guidance to complete fire PRAs (eight sites, all with peer reviews)
  - Feedback from students in training courses (2010 and 2011)
- Review by ACRS Subcommittee on Reliability and PRA

**All elements tested via variety of applications**



# Review, Testing and Trial Application (cont'd)

## Examples of changes to report from feedback

- Increased guidance on qualitative analysis (especially feasibility assessments)
- Simplified scoping approach to quantification
- Modified timing considerations for scoping approach
- Enhanced guidance for walkthroughs/talkthroughs
- Expanded treatment of spurious actuations/operations
- Simplifications in recovery analysis, dependency analysis, and uncertainty

**Review and experience substantially improved Guidelines**

# Advances Beneficial to Other Projects

- Fire HRA guidelines directly benefit other NRC HRA projects
  - New HRA development per SRM M061020
  - Site-wide Level 3 PRA Project
- Commonality of team members among projects facilitates coordination

# Advances from Fire HRA Guidelines: Examples

- Comprehensive guidance for all steps in HRA process
- Examples on how to address PRA Standard requirements
- Integration of HRA with larger PRA study
- Example of a quantification approach that addresses traceability concerns (i.e., scoping fire HRA approach)
- Detailed guidance on feasibility assessments
- Guidance on HRA tasks for ex-control room actions and challenging environmental conditions
- Framework for HRA for other challenges, e.g.,
  - Seismic PRA

# Examples of Advances (continued)

- Situations involving problems with cues and distractions
- Development of timing estimates (including treatment of uncertainties)
- Use of procedures other than EOPs
- Training materials for all HRA process steps

# Conclusions

- Project objectives have been satisfied
  - Comprehensive, useful guidance for fire HRA
  - Approach refined through testing and application in production PRAs
- Elements of Guidelines of significant value to other HRA research and development

**Project Team requests letter from ACRS**

