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Power Uprate Subcommittee Meeting

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7 ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
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11 proceeding of the United States Nuclear Regulatory
12 Commission Advisory Committee on Reactor Safeguards,
13 as reported herein, is a record of the discussions
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16 This transcript has not been reviewed,
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1 UNITED STATES OF AMERICA

2 NUCLEAR REGULATORY COMMISSION

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4 ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

5 (ACRS)

6 POWER UPRATE SUBCOMMITTEE MEETING

7 REGARDING POINT BEACH NUCLEAR PLANT

8 UNITS 1 AND 2 EXTENDED POWER UPRATE

9 + + + + +

10 OPEN SESSION

11 + + + + +

12 THURSDAY

13 FEBRUARY 24, 2011

14 + + + + +

15 ROCKVILLE, MARYLAND

16 + + + + +

17 The Advisory Committee met, at the Nuclear

18 Regulatory Commission, Two White Flint North, Room

19 T2B3, 11545 Rockville Pike, at 8:30 a.m., Sanjoy

20 Banerjee, Chairman, presiding.

21

22

23

24

25

1 COMMITTEE MEMBERS:
2 SANJOY BANERJEE, Chairman
3 WILLIAM J. SHACK, Member
4 JOHN D. SIEBER, Member
5
6 ACRS CONSULTANTS PRESENT:
7 MARIO V. BONACA
8 IVAN MALDONADO*
9 GRAHAM WALLIS
10
11 NRC STAFF PRESENT:
12 TERRY A. BELTZ, NRR/DORL
13 DYLANNE DUVIGNEAUD, NRR/DRA
14 STANLEY GARDOCKI, NRR/DSS
15 ALLEN G. HOWE, NRR/DORL
16 ANDREW JOHNSON, NRR/DCI
17 SAMUEL MIRANDA, NRR/DSS
18 BENJAMIN PARKS, NRR/DSS/SRXB
19 ANTHONY ULSES, NRR/DSS
20 LEONARD WARD, NRR/DSS/SNPB
21 ZEYNA ABDULLAHI, Designated Federal Official
22
23 * Participating via telephone
24
25

1 ALSO PRESENT:
2 ROBERT BAIN, Shaw
3 KEVIN BARBER, Westinghouse
4 DAVID DOMINICIS, Westinghouse
5 JORGE FONTES, Westinghouse
6 STEVE HALE, NextEra Energy
7 NORMAN HANLEY, Shaw
8 HARV HANNEMAN, NextEra Energy
9 TERRY JONES, NextEra Energy
10 JAY KABADI, NextEra Energy
11 BRETT KELLERMAN, Westinghouse
12 LARRY MEYER, NextEra Energy
13 MIKE MILLEN, NextEra Energy
14 MARK SHEAFFER, Westinghouse
15 D.J. TOMASZEWSKI, NextEra Energy
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2 8:29 a.m.

3 CHAIRMAN BANERJEE: (presiding) The

4 meeting will now come to order.

5 This is a meeting of the Power Uprate

6 Subcommittee of the Advisory Committee on Reactor

7 Safeguards. I am Sanjoy Banerjee, the Chairman of the

8 Point Beach Units 1 and 2 Extended Power Uprates

9 Subcommittee meeting.

10 ACRS members in attendance are Jack Sieber

11 and Bill Shack, and we also have in attendance former

12 ACRS Chairs Graham Wallis and Mario Bonaca, who will

13 be acting as consultants.

14 There is a concurrent meeting going on

15 with regard to Watts Bar, and there will be other

16 members who will join us, depending on topics being

17 discussed and their availability.

18 Joining us in a two-way telephone

19 conference is the ACRS consultant Ivan Maldonado.

20 Zeyna Abdullahi is the Designated Federal

21 Official for this meeting.

22 In today's meeting, the Subcommittee will

23 hear presentations by and hold discussions with the

24 NRC staff, NextEra, the licensee of Point Beach Units

25 1 and 2, and their consultants, Westinghouse.

1 The Point Beach units are two-loop PWR
2 Westinghouse that were originally licensed at 518
3 megawatts thermal. In 2003, it was approved for and
4 implemented a measurement uncertainty uprate to 1540
5 megawatts thermal.
6 Our discussion and review today is focused
7 on the licensee NextEra's request to operate the two
8 units at about 17 percent to 1800 megawatts thermal,
9 which is an increase of 260 megawatts thermal.
10 Uprates of this level that involve major plant
11 modifications are designated as extended power
12 uprates.
13 We are looking forward to hearing from the
14 staff and the licensee about the basis for their
15 conclusions that Point Beach Units 1 and 2 can operate
16 safely and meet all the regulatory requirements of the
17 uprated conditions.
18 The rules for participation in today's
19 meeting have been announced as part of the notice
20 previously published in The Federal Register.
21 Portions of today's meeting may be closed
22 to the public as needed in order to protect material
23 that is proprietary to licensee NextEra and its
24 consultants, Westinghouse.
25 A transcript of the meeting is being kept.

1 Therefore, we request that participants in this
2 meeting use the microphones located throughout the
3 meeting room when addressing the Subcommittee. The
4 participants should first identify themselves and
5 speak with sufficient clarity and volume so that they
6 may be readily heard.
7 We have provided a listen-only bridge
8 number for the members of the public. Please be
9 advised that the lines may not be very clear since we
10 are utilizing telephones that are not part of our
11 microphone system.
12 Okay. With that, we will start the
13 proceedings, and I call upon Mr. Allen Howe, Deputy
14 Director of the NRR, to start us off with introductory
15 remarks.
16 Thank you.
17 MR. HOWE: Thank you and good morning.
18 I am Allen Howe, Deputy Director of the
19 Division of Operating Reactor Licensing in the Office
20 of Nuclear Reactor Regulation.
21 I appreciate the opportunity to brief the
22 ACRS Power Uprate Subcommittee this morning. In the
23 interest of time, my opening remarks will be brief.
24 On April 7th, 2009, FPL Energy Point
25 Beach, now known as NextEra Energy Point Beach,

1 submitted a license amendment request for an extended
2 power uprate of approximately 17 percent for the Point
3 Beach Nuclear Plants Unit 1 and 2. The proposed EPU
4 would increase the maximum authorized power level for
5 each unit from 1540 megawatts thermal to 1800
6 megawatts thermal.
7 Next slide.
8 At this meeting, the NRC staff will
9 present to you the results of our very thorough safety
10 and technical review of the licensee's application.
11 During the course of our review, the staff had
12 frequent communications with the licensee, including
13 conference calls, letters, audits, and public
14 meetings. We believe this open dialog contributed
15 positively to the overall review.
16 NRC issued multiple rounds of Requests for
17 Additional Information, or RAIs, to the licensee.
18 RAIs span multiple technical disciplines, and they
19 were issued as they were developed to allow the
20 licensee sufficient time to review and respond to the
21 RAIs.
22 The most challenging review areas that you
23 will hear about today and tomorrow include the
24 following:
25 Steam generator tube rupture event and

1 margin to overfill analysis.

2 Post-LOCA boron precipitation.

3 High-energy line break methodology.

4 And staff concurrent review of other

5 licensing actions supporting the EPU, including the

6 Alternate Source Term and Auxiliary Feedwater

7 Modification License Amendment Request.

8 Overall, I am pleased with the

9 thoroughness of the staff's review. The staff has had

10 extensive interaction with the licensee on a diverse

11 set of technical issues.

12 Finally, my thanks to the ACRS staff who

13 greatly assisted us with the preparations for this

14 meeting.

15 At this point, I will turn over the

16 meeting to Terry Beltz, who is the Senior Project

17 Manager for this project.

18 MR. BELTZ: Okay. Thank you, Allen.

19 Good morning.

20 My name is Terry Beltz, and I am the

21 Senior Project Manager at NRR assigned to the Point

22 Beach Nuclear Plant.

23 As you know, we gave the ACRS less than 30

24 days to review the information supporting the Point

25 Beach EPU. The staff understands the burden that this

1 placed on the members. On behalf of the staff, I
2 would like to take this opportunity to publicly thank
3 the ACRS for accommodating the schedule and reviewing
4 the proposed EPU in such a short turnaround. The
5 staff appreciates the effort in this regard.
6 Over the course of the next two days, you
7 will hear presentation from NextEra Energy and the NRC
8 staff. The objective is to provide you sufficient
9 information related to the details of the EPU
10 application and the evaluation supporting the staff's
11 reasonable assurance determination that the health and
12 safety of the public will not be endangered by
13 operation of the proposed EPU.
14 Before I continue with the discussion of
15 today's agenda, I would like to present some
16 background information related to the staff's review
17 of the Point Beach EPU. As Allen previously
18 mentioned, the EPU would increase the maximum
19 authorized thermal power from the current licensed
20 thermal power of approximately 1540 megawatts thermal
21 to 1800 megawatts thermal, which represents
22 approximately a 17 percent increase in license rate of
23 thermal power for each unit.
24 The licensee submitted its EPU application
25 on April 7th, 2009, including the licensing report

1 which was provided as Attachment 5 to the application.
2 Included with the EPU application were also other
3 licensing actions, including a request for approval
4 for the aux feedwater modification, a review of high-
5 energy line break methodology, and changes to the RPS
6 and ESFAS setpoint methodology. Overall, there were
7 approximately 12 supplements to the application.
8 Finally, it should be noted that there are
9 still three amendments that are under NRC review,
10 including the Alternate Source Term Amendment, the
11 Auxiliary Feedwater Amendment, and the Setpoint
12 Methodology Amendment. These amendments are currently
13 undergoing NRC's staff final review and concurrence,
14 and these amendments are needed to support the EPU and
15 requirement implementation prior to implementation of
16 the EPU.
17 This slide is the topics for today's
18 discussion. NextEra Energy will start out providing
19 an overview of the EPU. NextEra and the NRC staff
20 will then each present their presentations on fuel and
21 core and safety analyses. The NRC staff will then
22 have a discussion and presentation on materials and
23 chemical engineering. And, then, finally, at the
24 close of the day, the NRC staff will provide a
25 presentation on source term and radiological

1 consequences.

2 This concludes my presentation as far as

3 the introduction. Unless there are any other

4 questions, I would like to turn over the presentation

5 to Mr. Larry Meyer and NextEra Energy. Mr. Larry

6 Meyer is the Site Vice President for the Point Beach

7 Nuclear Power Plant.

8 CHAIRMAN BANERJEE: The only thing, Terry,

9 is that there may be certain topics here which might

10 need more discussion. I wonder how inconvenient it

11 would be if some things spill over to tomorrow. Do

12 you have everything sort of orchestrated so that we

13 follow the schedule strictly in terms of --

14 MR. BELTZ: Oh, no, we can accommodate.

15 CHAIRMAN BANERJEE: You could accommodate

16 that?

17 MR. BELTZ: I believe so.

18 CHAIRMAN BANERJEE: Okay. Because there

19 could be topics and materials in chemical engineering,

20 for example, which might take more time. I don't

21 know, depending on member interest and following that

22 up.

23 MR. BELTZ: Okay.

24 CHAIRMAN BANERJEE: Now it depends on who

25 is here, who is going back, you know, from the

1 applicant. So, I am just saying that I will try to
2 stick to the agenda and, if necessary, instead of
3 keeping you here until seven o'clock at night, which I
4 hate to do, we might just -- tomorrow doesn't seem
5 like it is going beyond three o'clock. So, we might
6 take a topic and put it into tomorrow. But we will
7 play it by ear.
8 MR. BELTZ: Okay, we will play it by ear.
9 CHAIRMAN BANERJEE: I am just giving you a
10 heads-up.
11 MR. BELTZ: I will speak to the staff --
12 CHAIRMAN BANERJEE: Yes.
13 MR. BELTZ: -- at least the ones that are
14 giving presentations later in the day to make sure
15 they are still available for tomorrow.
16 CHAIRMAN BANERJEE: Well, it is not
17 necessarily going to happen. I try to keep my
18 meetings on time because I like to go to the gym
19 before dinner, but if it doesn't work out, I would
20 rather that we went into the next day than keep you
21 until 7:00 or something.
22 MR. BELTZ: Yes. I understand.
23 CHAIRMAN BANERJEE: Okay. Thank you. All
24 right.
25 DR. WALLIS: I am going to ask about these

1 three amendments still under review. They sound like
2 interesting topics.
3 CHAIRMAN BANERJEE: Right.
4 DR. WALLIS: Are you going to come back
5 with them when they are finished being reviewed or
6 what?
7 MR. HOWE: Right now, we don't have a plan
8 to come back. I believe that the information, the
9 Draft Safety Evaluations were provided to the members
10 of the Committee. But the nature of these amendments
11 are not something that in the past the ACRS has
12 requested to review.
13 DR. WALLIS: But you are going to make
14 conclusions about those amendments in the next couple
15 of days?
16 MR. HOWE: Yes, our plan is to move
17 forward, proceed with the issuance of those
18 amendments.
19 DR. WALLIS: So, you are prepared to
20 discuss all the technical topics in those amendments
21 with us now?
22 MR. HOWE: Yes.
23 DR. WALLIS: Okay. Thank you.
24 CHAIRMAN BANERJEE: Is there a specific --
25 will it happen as part of the agenda or is there a

1 specific item in the agenda which we might need to
2 discuss related to these amendments, to satisfy
3 Professor Wallis?
4 MR. BELTZ: I know the source term
5 radiological consequences will touch on the AST. As
6 far as the Auxiliary Feedwater Amendment, I don't know
7 if the licensee will be able to touch upon that.
8 So, as far as a discussion goes, the RPS,
9 the Setpoint Methodology, I don't believe there is any
10 discussion specifically during the meetings regarding
11 that amendment. Again, that amendment is specifically
12 Setpoint Methodology. So, it wasn't going to be
13 brought up at these meetings.
14 DR. WALLIS: I think the AWF one may give
15 rise to some discussion. The Setpoint Methodology is
16 so intricate, it is very hard to follow.
17 CHAIRMAN BANERJEE: Okay. I think that
18 will be fine. Let's see, if needed, we will put an
19 item at the end of the agenda and see what to do.
20 Okay? Fine. So, let's carry on, Terry, as you would
21 like.
22 Thank you very much, Allen and Terry. We
23 look forward to hearing back from you, of course.
24 MR. MEYER: Good morning.
25 CHAIRMAN BANERJEE: Good morning.

1 MR. MEYER: We can just advance to the
2 picture of the plant.
3 So, it is an honor and a pleasure to be
4 here to talk about Point Beach to the distinguished
5 audience. We are very proud of our plant.
6 I am going to talk a little bit about
7 history, give a little overview, and then Mr. Steve
8 Hale is going to talk about a few more details.
9 My name is Larry Meyer. I am the Vice
10 President of the site. I'm NextEra's senior executive
11 in charge of the facility.
12 CHAIRMAN BANERJEE: It looks so beautiful
13 that I thought initially it was a painting.
14 (Laughter.)
15 MR. MEYER: I joined the site in 2008 in
16 the spring. I have worked at many different
17 facilities, and as my wife and I were looking at the
18 site, she commented how pretty the site is. And it is
19 a very pretty site. During the winter, not as much.
20 But from a historical point of view, this
21 is what the plant looks like this. This was many
22 years ago.
23 This plant, Point Beach, is on the west
24 shore of Lake Michigan. It is about 30 miles
25 southeast of Green Bay.

1 Since this picture was taken, we have
2 built a large training center and a large
3 administrative building on the north side of the
4 plant, which would be to your left -- excuse me -- the
5 south side, which is to your left.
6 The plant is the pride and joy of about
7 700 employees who come to work every day very
8 committed and dedicated. We have a unionized
9 workforce. It is the IBEW 2150.
10 DR. WALLIS: Is that being considered by
11 the Governor in some way?
12 (Laughter.)
13 MR. MEYER: I hope he stays out of it.
14 I couldn't ask for a better workforce.
15 Our unionized workforce is dedicated and comes to work
16 every day, works hard. They have the very best
17 interest of the plant in mind.
18 Our motto, credo, at the plant is let's
19 make the plant a little better every day, with the
20 idea being that if everybody makes the plant a little
21 better every day, then as the days go on, the plants
22 gets much better.
23 DR. WALLIS: Now your cooling water is
24 taken from the lake?
25 MR. MEYER: It is.

1 DR. WALLIS: You have a tremendous plume
2 coming out of those pipes there.
3 MR. MEYER: Yes.
4 DR. WALLIS: It is remarkably noticeable.
5 MR. MEYER: Yes, one can notice it.
6 DR. WALLIS: It goes a long way and a
7 different color, too.
8 MR. MEYER: The lake is deceiving. My
9 office, which you can't see it here because it is
10 built since this photograph was taken. But, as I look
11 out my office, many days with the sun shining on the
12 lake, you would think you were in the Caribbean, but
13 if you go into the water, you would be quickly
14 corrected from that false notion because it is very
15 cold, very cold water. It is a very cold lake.
16 From a history point of view, I think,
17 actually, the Chairman covered some of this, but we
18 are a two-loop Westinghouse design. It is a very
19 robust design. Bechtel is our original
20 architect/engineer, and the steam generators were
21 replaced in 1983 on Unit 1 and 1996 on Unit 2.
22 As you indicated, we did recapture some
23 uncertainty in 2002 by going to the leading-edge full
24 meter feedwater plant.
25 CHAIRMAN BANERJEE: Is that a check plus

1 of is it LEFM? You know, check plus has two separate
2 beams on two sides.
3 MR. MEYER: Yes, it is a check plus.
4 CHAIRMAN BANERJEE: It's a check plus?
5 And could you just expand a little bit about the once-
6 through condenser cooling?
7 MR. MEYER: Sure. Well, it is unlike a
8 cooling tower. If you could just go back to the
9 pictures of the plant, please, Jay?
10 So, there is a pump house, which is this
11 structure right here. There's four large circulating
12 water pumps, and they will take water from the lake
13 and it flows through the condensers. Each of the
14 units has two water boxes in the condenser, and so the
15 water flows through the condenser and then it just
16 comes back out and back into the lake. And it is a
17 very simple design.
18 CHAIRMAN BANERJEE: Do you have any
19 biological fouling on this?
20 MR. MEYER: Yes. Yes, we do. We treat
21 that with -- and it is interesting, the lake is
22 changing. The lake changes sometimes. I think we
23 tend to think of the lake as sort of constant, and it
24 is really an organism.
25 We do have micro and macro fouling, and we

1 use a combination of chemicals that are well-proven to
2 take care of that situation.
3 CHAIRMAN BANERJEE: Do you use balls?
4 MR. MEYER: We do not, no, and I am
5 thankful for that.
6 CHAIRMAN BANERJEE: Otherwise, you would
7 get wear, correct?
8 MR. MEYER: Well, every time I would look
9 out my office I would see those balls the floating in
10 the lake because that is what happens when you have
11 the Amertap System.
12 MEMBER SIEBER: Do you have zebra mussels
13 there?
14 MR. MEYER: We do, sure. Yes, we do have
15 some. And what we do is, at a certain periodicity, we
16 will maneuver our intake structure to take some of the
17 discharge from one of the units and shortcircuit it
18 back in to raise the temperature of the water coming
19 back into the plant. And, then, we will inject
20 chemicals that will do a mass killing of the zebra
21 mussels.
22 MEMBER SIEBER: Yes.
23 MR. MEYER: And we do that at certain
24 intervals.
25 MEMBER SIEBER: Where is that outfall on

1 that picture?

2 MR. MEYER: The outfall is coming out

3 right by those two structures.

4 MEMBER SIEBER: And the inlet is in

5 between the two structures?

6 MR. MEYER: Yes, the inlet is actually

7 sort of approximately --

8 MEMBER SIEBER: Oh, okay. You have deep

9 water.

10 MR. MEYER: Under water, yes.

11 MEMBER SHACK: So, when the lake level

12 goes down, there is not a problem.

13 MR. MEYER: Actually, well, it is

14 interesting. The lake does provide the static head.

15 And so, Lake Michigan right now is at a historical

16 low. And so, we can see that in the performance of

17 our system. We have margin. The lake level does

18 cause an effect on the head, but it is not a

19 remarkable effect.

20 CHAIRMAN BANERJEE: So, to accommodate the

21 uprate, how is that going to, let's say, what are the

22 effects on the cooling water streams that will occur

23 there?

24 MR. MEYER: Our current circulating water

25 pump and condensers are sufficiently capable of

1 handling the increased power level. We will be
2 adjusting our condenser vacuum setpoint. We will be
3 increasing it slightly.
4 A bigger effect is actually on something
5 that we call a condensate cooler. What that is is it
6 really is the cooler for the air in the generator.
7 The air in the generator is cooled by the condensate.
8 Before the condensate goes back to the lake, it goes
9 through this condensate cooler, and that we don't have
10 enough margin on with the uprated generator. So, we
11 are putting in higher capacity condensate coolers.
12 CHAIRMAN BANERJEE: The cooling water will
13 have a higher delta T?
14 MR. MEYER: Yes.
15 CHAIRMAN BANERJEE: And the flow rates
16 would be roughly the same?
17 MR. MEYER: Yes.
18 CHAIRMAN BANERJEE: And the cooling water
19 comes out near the surface waters? Where is the
20 outlet in terms of depths for the cooling waters?
21 MR. MEYER: It is several feet below the
22 water. It is not right at the surface.
23 CHAIRMAN BANERJEE: It does not enter the
24 surface waters? It mixes?
25 MR. MEYER: It would mix, yes.

1 CHAIRMAN BANERJEE: All right.

2 MEMBER SIEBER: Now you, obviously, will
3 have an increase in vacuum? And what is your pre-
4 uprate typical summer vacuum level, and what do you
5 expect that to be after the uprate?

6 MR. MEYER: I am going to have to defer to
7 my operator in the room, if I could, to answer that,
8 that question. That would be Mike.

9 Mike, do you have that information?

10 This is Mike Millen.

11 MEMBER SIEBER: It varies from day to day?

12 MR. MEYER: It does. It does.

13 MEMBER SIEBER: An average would be good.

14 MR. MILLEN: Yes, I am Mike Millen. I'm
15 the operations lead the Point Beach uprate project.

16 MEMBER SIEBER: Okay.

17 MR. MILLEN: The normal condenser vacuum
18 is around one and a half, under 2 inches.

19 MEMBER SIEBER: Okay.

20 MR. MILLEN: And with the power uprate, we
21 are going to be operating nominally about 3 to 3.5
22 inches.

23 MEMBER SIEBER: Okay. That is a
24 significant increase.

25 MR. MILLEN: It is quite a bit of

1 difference.

2 MEMBER SIEBER: And that will place a

3 higher load on the tail-end of the low pressure

4 section of the turbine because the higher temperature

5 typically means more moisture?

6 MR. HANLEY: Right. You get some

7 performance change due to the higher pressure in the

8 condenser.

9 MEMBER SIEBER: I'm sorry. I can't hear

10 you.

11 CHAIRMAN BANERJEE: You have to identify

12 yourself.

13 MR. HANLEY: I'm sorry. Norman Hanley

14 from Shaw.

15 You will get performance, you know,

16 because, your high pressure in your condenser will

17 diminish some of your performance at the higher

18 condenser pressure.

19 MEMBER SIEBER: Do you expect to have

20 deratings on summer days?

21 MR. HANLEY: No.

22 MEMBER SIEBER: No?

23 MR. HANLEY: No, they are going to be able

24 to power; you know, through the summer, they will be

25 able to handle the condenser because the water is not

1 that warm in Lake Michigan. But, right now, there is
2 no plans to have to depower --
3 MEMBER SIEBER: Now Kewaunee Plant is just
4 to your north?
5 MR. HANLEY: Correct.
6 MEMBER SIEBER: And Oak Creek is to your
7 west? That is a cold plant.
8 MR. MILLEN: Oak Creek is farther south,
9 south of Milwaukee.
10 MEMBER SIEBER: Okay.
11 MR. MEYER: What I would like to emphasize
12 on this slide is that NextEra is very dedicated to
13 this plant. Since we bought it, achieved ownership in
14 late 2007, we have increased staffing at the site from
15 580 people to 700 people.
16 We have made a number of wholesale
17 improvements in the plant. One thing we do is we find
18 out what equipment problems are bothersome or
19 troubling the operators.
20 And in early 2008, there were about 250 of
21 those, and we have worked that down to 50 at this
22 point. And along the way, we lowered our threshold
23 several times.
24 CHAIRMAN BANERJEE: What was, let's say,
25 the top problem that was bothering the operators?

1 MR. MEYER: Well, there were many issues.
2 Like, for example, there was a recorder over where we
3 affect reactivity of the reactor with the control
4 rods. There was a recorder that monitors reactivity
5 that hadn't worked in many, many years. And so, that
6 was one of the items.
7 There were problems with the turbine hall
8 sump design. They kept bringing in nuisance turbine
9 hall sump alarms in the control room.
10 There were controllers that didn't work.
11 They had to be put on manual.
12 And, you know, the plant was safe to
13 operate, but it wasn't excellent. And so, we have
14 worked off, we have invested millions and millions of
15 dollars each year.
16 In 2008 -- another sort of indication of
17 the health of the plant is certain backlogs. And so,
18 there was a back log of corrective action items that
19 were in the thousands, and today's backlog is 450.
20 MEMBER SIEBER: It sounds like the
21 material condition of the plant a couple of years ago
22 was not very good.
23 MR. MEYER: Yes, I think that is a fair
24 assessment, sir. There is sort of a long history
25 involved with the different owners and operating

1 arrangements.

2 MEMBER SIEBER: Well, that is actually a
3 concern because, particularly if you are running close
4 to specification limits or out of specs for long
5 periods of time, you accelerate the degradation of
6 components in that process. And for the operators, I
7 think it places the operators in very much of a
8 disadvantage as far as responding to off-normal
9 conditions or perhaps even an incident or accident.

10 MR. MEYER: Yes, we will be providing
11 information along those lines to demonstrate that we
12 have made an awful lot of progress in that area.

13 MEMBER SIEBER: Well, I think that is
14 important and you are investing a lot of money now in
15 a relatively old plant with perhaps 20 more years to
16 go.

17 MR. MEYER: Right.

18 MEMBER SIEBER: But you are going to be
19 stressing every component in the plant to a higher
20 degree, higher steam flow, higher temperatures, and so
21 forth, that the materials condition becomes even more
22 important than it has been in the past.

23 Have you made any assessment as to the
24 remaining life of critical components like steam
25 generators? You know, your steam generators were

1 replaced in the early eighties.

2 MR. MEYER: Yes, absolutely.

3 MEMBER SIEBER: They are not wear-free,

4 and even though the industry has learned a lot, there

5 are still some issues in steam generator chemistry and

6 degradation, tube degradation, moisture separator

7 degradation.

8 What have you done to assess the condition

9 of these components, the major components?

10 MR. HALE: Hi. My name is Steve Hale. I

11 am the Project Manager for the EPU and AST efforts.

12 The process we follow in assessing

13 material condition and equipment capability is pretty

14 rigorous. It involves the system engineers. They are

15 tied into it. And we look at each system and

16 component relative to what we are going to be putting

17 it through from an EPU standpoint.

18 But, as part of that process, we also

19 evaluate existing material condition, get input from

20 the plant, and that is taken into account in the

21 evaluations that we perform. And in some cases, we

22 have had to replace equipment.

23 For example, we are replacing all the

24 feedwater heaters in the plant.

25 MEMBER SIEBER: Right. Yes, I noticed

1 that.

2 MR. HALE: And it also gave us an

3 opportunity to put erosion-resistant materials in the

4 new feedwater heaters.

5 MEMBER SIEBER: Well, you are doing that

6 probably because of the equipment's age, but you also

7 need additional capacity.

8 MR. HALE: That is true. I mean it is a

9 combination.

10 MEMBER SIEBER: You do that regardless of

11 the material condition to get this amount of

12 additional power out of the turbine plant.

13 MR. HALE: But I think what you will find

14 in this uprate, though, we have also chosen to do some

15 things that we wouldn't maybe have to have done as

16 part of the EPU, as part of an overall upgrade for the

17 plant in terms of availability and reliability. And

18 the AFW system is a good example of that.

19 So, I think the process we followed is a

20 process that Shaw has utilized through a number of

21 uprates. I was the Project Manager for the Seabrook

22 power uprate as well as one at St. Lucie some years

23 ago.

24 And their process is very rigorous and it

25 involves the plant engineers, who probably know best

1 the condition of their system.

2 MEMBER SIEBER: Do you currently have any

3 leaking steam generator tubes?

4 MR. HALE: No, we don't.

5 MEMBER SIEBER: How many do you have

6 plugged on a percentage basis?

7 MR. HALE: I think we have that in the

8 backup material.

9 MR. HANNEMAN: Hi. This is Harv Hanneman

10 from NextEra, Point Beach.

11 In the Unit 1 steam generators, which were

12 replaced in 1983, we have five tubes out of 3214

13 plugged in the alpha generator and six out of 3214 in

14 the --

15 MEMBER SIEBER: And what model are the

16 replacements?

17 MR. HANNEMAN: Those are Model 44F.

18 MEMBER SIEBER: F, right.

19 MR. HANNEMAN: Yes.

20 MEMBER SIEBER: Okay. Forty-four thousand

21 square feet.

22 MR. HANNEMAN: Yes. And, then, in the

23 Unit 2 steam generators, which were replaced in 1996,

24 the Bravo steam generator has four tubes plugged and

25 the alpha generator has no tubes plugged. We don't

1 have any active degradation mechanisms going on right
2 now --
3 MEMBER SIEBER: Okay.
4 MR. HANNEMAN: -- based on the last
5 reports that we have submitted to the NRC.
6 MEMBER SIEBER: What chemistry regime are
7 you using in the feedwater steam generators? All
8 volatile --
9 MR. HANNEMAN: All volatile chemistry
10 control, yes.
11 MEMBER SIEBER: And when did you start all
12 volatile?
13 MR. HANNEMAN: We started that early in
14 the life of the plant. I think it was back in like
15 1973 or so.
16 MEMBER SIEBER: Okay. And one of the
17 early advances was MOLAL control. You know, because
18 you can keep shoving chemicals in there and end up
19 with a pretty active soup, but still meet all the
20 constraints. And MOLAL control is to try to come up
21 with a chemical balance that still met all the
22 requirements but without having chemicals that can
23 disassociate and hide out in crevices.
24 So, I take it you are on the MOLAL
25 control, M-O-L-A-L?

1 MR. HANNEMAN: I am not familiar with that
2 term. I don't know.
3 MEMBER SIEBER: Okay. Well, maybe you
4 have --
5 MR. HANNEMAN: We follow the EPRI
6 guidelines for secondary water chemistry control.
7 MEMBER SIEBER: Okay. These are the
8 Westinghouse guidelines?
9 MR. HANNEMAN: Well, they are the EPRI --
10 CHAIRMAN BANERJEE: Are you going to
11 address these under materials and chemical engineering
12 or are these --
13 MEMBER SIEBER: Well, I am just trying to
14 get an idea --
15 CHAIRMAN BANERJEE: Yes.
16 MEMBER SHACK: I didn't see any slides
17 MEMBER SIEBER: -- of what kind of
18 condition the plant is in.
19 MR. HANNEMAN: Right. As I said, we have
20 an active program, of course, of inspection required
21 by our tech specs. We also do secondary sludge
22 lancing every outage. And the last inspection showed
23 no active degradation mechanisms in either units'
24 steam generators.
25 MEMBER SHACK: You have no history of any

1 kind of cracking in the alloy 600 steam generator?
2 MR. HANNEMAN: That's correct. Unit 1 has
3 the thermally-treated alloy 600, and the Unit 2 steam
4 generators, which were replaced later, have the
5 thermally-treated alloy 690.
6 MEMBER SHACK: That is pretty old 600 TT.
7 I mean you guys must have been early.
8 MR. HANNEMAN: But we have shown no
9 degradation. So, we have no evidence --
10 MEMBER SHACK: You are going to kick up
11 your crack growth rates about 20 to 30 percent. Your
12 initiation times will go down about 20 to 30 percent
13 as you raise temperature.
14 MEMBER SIEBER: Because of the TH.
15 MR. HANNEMAN: We are raising T Hot as
16 part of the uprate, but we believe it is still well
17 within where other plants with that similar material
18 operate; for example, Seabrook.
19 MEMBER SHACK: Well, it was operating with
20 alloy 600 steam generators before.
21 MR. HALE: Yes, but -- again, this is
22 Steve Hale -- if you look at temperatures, the four-
23 loopers run a lot hotter than the two-loopers.
24 MEMBER SIEBER: But we'll get to this
25 later on again, I think, in your presentation. I

1 would like to explore that.

2 CHAIRMAN BANERJEE: That's why, yes, I

3 said we might take more time on this issue.

4 MEMBER SIEBER: Well, that is one of my

5 concerns.

6 CHAIRMAN BANERJEE: Yes. Right. It is a

7 concern of a lot of people on the Committee.

8 MR. MEYER: Sure. I don't want to mislead

9 the Committee. The material condition of the plant

10 today, and for the last several years, we have

11 invested enough, focused on the right areas, that I am

12 confident that it is at very high levels.

13 In fact, we measure the number of

14 deficiencies in a number of ways in the industry. One

15 of those is the number of corrective maintenance work

16 orders that are open. We have zero.

17 And we are a two-unit site. We have 290

18 elective maintenance work orders that are open, and we

19 are in the top decile, if not in the top of the

20 industry, for a low maintenance backlog.

21 Also, over the last couple of years, EPRI

22 has got a very good indicator of material condition.

23 It is called the Equipment Reliability Index, and it

24 measures a whole bunch of things. Over the last three

25 years, we have gone from 64 percent to nearly 90

1 percent on both units on that Index.

2 So, actually, in 2009 and 2010, both Unit

3 1 and Unit 2 had breaker-to-breaker runs, and Unit 2

4 had an all-time lifetime record run of over 500 days.

5 CHAIRMAN BANERJEE: Have you replaced your

6 sumps recently? Of course you did probably. Sump

7 screens?

8 MR. MEYER: Yes. In 2008 and 2009, we

9 increased the surface area by a factor of 100.

10 CHAIRMAN BANERJEE: What type of screens

11 do you have at the moment?

12 MR. MEYER: I don't know the answer to

13 that question. Does anyone know the type of screens

14 we have?

15 CHAIRMAN BANERJEE: Bucket screens,

16 strainers?

17 MR. MEYER: They're strainers. They are

18 like sort of cubicle modules and they all stack in

19 series.

20 CHAIRMAN BANERJEE: Oh, I know what those

21 are, yes.

22 MR. MEYER: So, speaking of that, we are

23 very committed to maintaining the integrity of our

24 recirc path and, in addition, to increasing our

25 strainer surface by a hundredfold on each unit. We

1 are very aggressively removing and replacing
2 insulation on both units.
3 CHAIRMAN BANERJEE: You have taken fibrous
4 insulation out?
5 MR. MEYER: We have, yes. On Unit 1, we
6 have replaced the insulation on the pressurizer and
7 both steam generators, and we started the loops. And
8 on Unit 2, which is having its refueling outage
9 upcoming, we will be completing its pressurizer steam
10 generators and we will be starting on one of the
11 loops.
12 So, we recognize the importance of that
13 initiative and are fully committed to it.
14 MEMBER SHACK: The original insulation
15 was?
16 MR. MEYER: I can't recall the name of it,
17 but it is one of the worst --
18 CHAIRMAN BANERJEE: Was it Nucon, some
19 variety of Nucon? Do you know?
20 MEMBER SHACK: Fiberglass, rockwool,
21 calcite.
22 MR. MEYER: Right. A lot of it is even
23 asbestos, I think.
24 MEMBER SHACK: Good old plant.
25 CHAIRMAN BANERJEE: Right.

1 MR. MEYER: But it is good for the plant
2 to replace that, not only from a safety perspective,
3 but also as our maintenance people, we have to do
4 maintenance on those components. That insulation is
5 so old that --
6 CHAIRMAN BANERJEE: Have you finished your
7 integrated review for GSI-191?
8 MR. MEYER: We have done a lot of analysis
9 for GSI-191, but I am not satisfied that we have used
10 the most conservative assumptions and that all of the
11 parameters have been set correctly. And so, we are
12 redoing that this year, by the end of the year.
13 We have done it. We have actually done it
14 twice now. But this year we are doing it again with
15 what I think are more ironclad parameters and
16 assumptions. By the end of the year, we will have it
17 pinned down exactly what the remaining scope will be.
18 But we are not waiting for that. I am removing a
19 pile of insulation in Unit 2 this coming outage.
20 CHAIRMAN BANERJEE: That's fine. Of
21 course, the concern is that you would have more energy
22 put into the containment in case of a LOCA with the
23 EPU. And do you need any containment overpressure
24 right now, based on your current work, to meet the
25 GSI-191 requirements or the NPSH?

1 MEMBER SIEBER: Recirculation --

2 CHAIRMAN BANERJEE: Long-term

3 recirculation.

4 MR. HALE: We intend to cover some of that

5 material later on in the presentation.

6 CHAIRMAN BANERJEE: Okay. Because we

7 asked that question.

8 MR. HALE: Right, right.

9 CHAIRMAN BANERJEE: We looked for it and

10 we didn't see it.

11 MR. HALE: Right. We have included some

12 of it in the backup slides. I will cover it in my

13 portion of the presentation.

14 CHAIRMAN BANERJEE: Fine. We will defer

15 that now.

16 MR. HALE: Okay.

17 MEMBER SIEBER: Yes, we ought to let them

18 talk a little bit.

19 (Laughter.)

20 MR. MEYER: Can we go to the next slide,

21 please?

22 So, just for the formality, then, we are

23 requesting the approval of approximately 17 percent.

24 I know you have said it, but we will say it is 17

25 percent uprate to a power level of approximately 1800

1 megawatts thermal.

2 We have made a number of modifications

3 already that are symbiotic with life extension and

4 replacing older components. On Unit 2, for example,

5 we have put in a brand-new main transformer, and it

6 will not only handle the uprated power, but our prior

7 transformer was nearing the end of life.

8 On Unit 2, we have put in a main generator

9 output breaker. The plant didn't have an output

10 breaker before. That improves some of our margins

11 from an electrical perspective.

12 We are also well advanced in replacing our

13 motor-driven auxiliary feedwater system. We have got

14 a new system for the motor-driven pumps installed. It

15 is a pipe-type, and we are just in the final stages of

16 doing the electrical connections on that.

17 MEMBER SIEBER: As I recall that model

18 plant, you had both motor-driven and a steam-driven

19 aux feed pump all in the same cubicle?

20 MR. MEYER: Yes.

21 MEMBER SIEBER: How do you deal with power

22 protection on that?

23 MR. MEYER: It's dealt --

24 MEMBER SIEBER: Do you have another pump

25 someplace else that is not that fire zone?

1 MR. HALE: Again, this is Steve Hale.

2 There are some issues related to fire
3 protection with the existing system. They are in
4 separate cubicles. You have a turbine-driven and then
5 a motor-driven, and a turbine-driven and motor-driven
6 that are in separate cubicles. But one of the things
7 we are doing as a result of the new installation is
8 installing motor-driven pumps somewhat far removed
9 from the existing auxiliary feedwater pumps. We are
10 also resolving some of the issues that we have had
11 with the existing system.

12 MEMBER SIEBER: Yes, some licensees have
13 actually put a spare aux feed pump in the turbine
14 building away from the aux building fire issues.

15 MR. HALE: Yes, once you see what we have
16 done in the AFW modifications, which I will cover --

17 MEMBER SIEBER: You're going to explain
18 this?

19 MR. HALE: Yes. Yes.

20 MEMBER SIEBER: I'll wait.

21 MR. HALE: Okay.

22 DR. BONACA: I have a question with the
23 licensing basis of the plant. In the SER, there is an
24 evaluation and there are many exceptions or
25 modifications from the current licensing basis. It

1 would be beneficial for us to have an understanding of
2 simply what the basic differences are from the current
3 licensing basis. Is there a place where you are going
4 to give us that information?
5 MR. HALE: Yes. In fact, I think both we
6 and the staff will cover some of those areas where we
7 deviate from the current licensing basis.
8 DR. BONACA: Okay.
9 DR. WALLIS: Your fuel assembly isn't
10 changed?
11 MR. HALE: No, we had already --
12 DR. WALLIS: How do you get your EPU?
13 You're going to tell us later, but, very quickly, how
14 do you get this high power out of the same fuel
15 assembly?
16 MR. HALE: The power comes from higher
17 temperatures and more energy in the core.
18 MR. MEYER: We load more fresh fuel into
19 the core at any one time, yes.
20 DR. WALLIS: Reload? Okay.
21 MR. MEYER: So, the next slide, I just
22 want to show this. This is sort of the theme for the
23 plant. We are pretty excited about it. These are
24 some of the plant workers. "More generation for our
25 next generation."

1 And in a moment, I will talk a little bit
2 about this really just about the power increase. It
3 is a great time for the plant because Unit 1 has just
4 entered extended license operation. And so, it has
5 run for 40 years. So, along with license renewal,
6 plus our workforce is changing over as well, younger
7 people. And so, uprate and license renewal and a
8 younger workforce all coming together, "More
9 generation for our next generation." And it is
10 meaningful to us. And those are some of the plant
11 employees.
12 So, this uprate, it is a real large
13 package, and it is really about doing much more than
14 achieving a power uprate. It is actually about making
15 the plant safer, making the plant more reliable, and
16 also a new technology, some new technology. And it is
17 resolving what I would call some of the last, some of
18 the more difficult legacy issues that the plant has
19 had, and we are rolling that all in to this package.
20 And I will elaborate on that in just a little bit.
21 Next slide.
22 So, for us, uprate, overall power uprate
23 means a better plant overall. It is a safer plant.
24 As we have talked about, upgraded auxiliary feedwater
25 systems, our current, we have installed two brand-new,

1 motor-driven auxiliary feedwater pumps, and we are
2 improving, as part of the Alternate Source Term, we
3 are improving the control room ventilation system.
4 These result in a safer plant in a number
5 of ways, but both the core damage frequency and the
6 large early release factor are reduced by these
7 changes. My team will explain why, but a couple of
8 factors play into that.
9 First of all, the new auxiliary feedwater
10 system eliminates a number of manual operator actions
11 that are currently required. And, also, we are
12 installing some air-compressing capability that is not
13 reliant on service water. And so, the compressed air
14 for the instrument air system, we are removing the
15 dependence of the instrument air on service water.
16 And that buys us quite a bit from a core damage
17 frequency perspective as well. And we will be
18 providing some more details on that.
19 There is more operational margin in the
20 upgraded plant. We have already modeled all of the
21 changes on the simulator.
22 Just sort of as a real quick recap of
23 those, there's brand-new feedwater pumps, brand-new
24 condensate pumps involved, new feedwater heaters in
25 the condensers. We have already replaced all the

1 feedwater heaters outside of the condensers with
2 brand-new feedwater heaters.
3 We have got much better minimum recirc
4 flow control on the feed pumps. We are changing the
5 feed --
6 MEMBER SIEBER: Do you have electric pumps
7 or steam-driven?
8 MR. MEYER: Electric. Yes, sir, electric.
9 MEMBER SIEBER: How did you get the feed
10 valves to turn down better than typical? Because,
11 usually, at 20 percent or less flow, they are
12 unstable, lots of vibration, particularly with
13 electric pumps. Do you use bypasses?
14 MR. MEYER: Yes. Yes, there is a bypass,
15 recirc.
16 MEMBER SIEBER: There are float control
17 valves, bypasses?
18 MR. MEYER: Yes.
19 MEMBER SIEBER: Okay. So, on the startup,
20 you will operate on bypasses to what power level?
21 Twenty percent?
22 MR. HALE: Yes, around in there, about 15,
23 20 percent, something like that.
24 MR. MEYER: We are also installing
25 feedwater isolation valves which the plant currently

1 doesn't have, and that is a safety enhancement, too,
2 for the peak.
3 MEMBER SIEBER: Yes, I thought every plant
4 was required to have --
5 MR. MEYER: So, a lot of new equipment,
6 and when we modeled this on the simulator for some
7 typical situations -- you know, we don't want these
8 situations to occur, but for our operators to respond,
9 like, for example, if we lose a feedwater pump or if
10 we lose a condensate pump or if we lose a heater drain
11 pump, the new plant -- I call it the "new plant" --
12 the upgraded plant actually gives the operators more
13 time to respond. There is more margin.
14 So, it is a better plant. It is a safer
15 plant, and it is also a better from an operations
16 perspective. It is a more reliable plant because we
17 will have many new components.
18 And a number of what I would refer to as
19 the last bastion of issues that we need to deal with
20 at the plant, some of the more longer-term legacy
21 issues, are resolved. There is about 10 or 12 of
22 those that are resolved as part of the uprate project.
23 Just as an example, our 480-volt
24 electrical distribution system doesn't have a lot of
25 margin on it. And there are important loads powered

1 off that power supply, like the instrument air
2 compressors are and the charging pumps are and battery
3 chargers are. Currently, our auxiliary feedwater pump
4 motors are. So, all of these big loads --
5 MEMBER SIEBER: They're 480-volt?
6 MR. MEYER: They're 480 volts, yes.
7 MEMBER SIEBER: That's surprising.
8 MR. MEYER: And so, all of these big loads
9 on the 480-volt system puts the operators in a tight
10 box on what loads they can have connected to which
11 switchgear at any one time. It is all procedurally-
12 controlled.
13 We call that an operator burden. And the
14 change involves moving the motor-driven auxiliary
15 feedwater pump motors from 480 volts. Their new ones
16 are powered for 4160. We have just taken a huge load
17 off the 480-volt system, which then provides the
18 operators with much more flexibility.
19 That is just an example of one of the
20 issues that makes this a better plant from the
21 operations perspective.
22 DR. WALLIS: Have you mentioned the MSIVs
23 yet? I think you modified them, too.
24 MR. MEYER: Yes.
25 DR. WALLIS: You did it probably to reduce

1 flow-induced vibration?

2 MR. HALE: Yes.

3 DR. WALLIS: How did you understand flow-

4 induced vibration well enough to know what to do?

5 MR. HALE: Well, I think if you look at

6 vibration, certainly a lot of it has to do with

7 monitoring and also experience. And we have to draw

8 on Shaw's experience, who has done probably, I don't

9 know, Norm, but probably 80 or 90 percent of the

10 uprates in the country.

11 And one of the areas we knew that we would

12 have to address with the increases in steam flow were

13 the MSIVs. These are the old reverse-check-type

14 MSIVs. So, the actual valve manufacturer has an

15 upgrade package specifically related to the increases

16 in flow.

17 CHAIRMAN BANERJEE: I guess he is really

18 asking about the acoustic waves, to address the

19 vibrations.

20 DR. WALLIS: Do you do some analysis of

21 this or do you do it by walkdown? You actually

22 increase the flow and see what happens or do you

23 analyze it first in some way?

24 MR. HALE: Our vibration approach is to

25 look at areas that are currently problems from a

1 vibrational standpoint. We establish some criteria
2 that is in a test guide -- I can't remember the number
3 -- that provides you acceptance criteria with that.
4 And we are going to be very slow and deliberate in our
5 increase in power.
6 From a velocity standpoint, we know what
7 systems we need to focus on. We don't anticipate any
8 issues or problems with it. But we will monitor it as
9 we go up.
10 MR. BAIN: I'm Bob Bain from Shaw.
11 We use an OM standard 2003 reconciled to
12 OM standard 2007. We have used a historical
13 displacement approach for all the piping systems. We
14 have done about 24 units since 1999. We have done
15 seven walkdowns, the last one just last week at Point
16 Beach, where we have monitored inch by inch every inch
17 of the power systems, main steam, feedwater, valves,
18 heater drain system, extraction steam system.
19 Point Beach actually is a very solid, firm
20 plant. This is compared to plants like Surry, North
21 Anna, Beaver Valle, Ginna, Comanche Peak, Millstone.
22 So, we have a long history.
23 Even last week, we had baselined this five
24 times in 2008, again in 2009, and again just last
25 week, and the plant remains very solid-based.

1 As Steve said, when power ascension
2 happens, we will be doing at every plateau, 20
3 percent, 50 percent, 70 percent, 80 percent, 85, 90,
4 95.
5 And it is visual-based, hand-held
6 displacement. Piping vibration, unlike equipment
7 vibration, is low frequency, low acceleration. So,
8 really, the key parameter is actually displacement.
9 We monitor displacements and proactively
10 -- and we do this when the plants did the feedwater
11 heater modifications, as Larry mentioned, in 2008 and
12 2009, 2009, 2010, we actually made online some more
13 changes to mitigate consequences of vibration. We
14 will do the same thing as we come out of these
15 upcoming outages. As the power levels are attained,
16 if we notice anything that is potentially detrimental,
17 we do basically online fixes, small fixes to change
18 the displacement profile.
19 MEMBER SIEBER: Well, as you go up in
20 power, though, you are going to get into an area that
21 is sort of unknown because you may hit natural
22 frequencies of power levels higher than the plant has
23 ever run before.
24 MR. BAIN: That's true, yes.
25 MEMBER SIEBER: But you are confident that

1 you will pick that up?

2 MR. BAIN: Yes. Again, since we have been

3 doing this pretty much nonstop the last 11 years,

4 because that same issue, like you say, if you hit a

5 natural frequency, it is asymptotic. That is why we

6 are continually -- and I mean continually -- for about

7 10 to 12 days walking down the entire plant, looking

8 for exactly what you just mentioned, basically.

9 So, we have anticipated that. We have

10 seen it in the past, and we know the fixes to make

11 those things okay.

12 MEMBER SIEBER: Now you are looking at

13 displacement, right? You are not --

14 MR. BAIN: Yes.

15 MEMBER SIEBER: -- doing acoustic

16 monitoring?

17 MR. BAIN: Am not, right, yes.

18 MEMBER SIEBER: Okay.

19 CHAIRMAN BANERJEE: That was, I guess, the

20 question.

21 MEMBER SIEBER: Yes.

22 CHAIRMAN BANERJEE: Right.

23 MEMBER SIEBER: Acoustic monitoring

24 sometimes has some advantages, but you can do an

25 adequate job with displacement, provided you cover the

1 plant properly.

2 MR. BAIN: Right, yes. And again, it is

3 such low frequency. Again, this is not the same as,

4 you know, steam dryers on BWRs.

5 MEMBER SIEBER: Yes.

6 MR. BAIN: And it is not the same issue as

7 turbine problems or pump problems.

8 MEMBER SIEBER: Or a feedwater valve

9 that's --

10 MR. BAIN: Right. Also, as Larry

11 mentioned, with the new FIVs going in the facade

12 building and the rate valves, which are actually in

13 the turbine building, and the bypasses on the west

14 wall, we are continually -- continually -- monitoring

15 those locations because just a slight change in the

16 position of the valve can make a big difference in the

17 response.

18 But the good thing, of course, with Point

19 Beach as a PWR, the access to all these systems is

20 readily available, and you can really have really

21 continual monitoring.

22 CHAIRMAN BANERJEE: Are we going to talk a

23 little bit about this program under power ascension

24 and testing?

25 MR. HALE: Yes, we are.

1 CHAIRMAN BANERJEE: Okay. So, we will
2 revisit it? Obviously, this is also one of the areas
3 we are concerned about.
4 MEMBER SHACK: You know, one of the tables
5 in the application gives some alternating strains, and
6 it refers to Ginna. Now are those measurements at
7 Ginna? Or it is based on some analysis done for
8 Ginna?
9 MR. HANLEY: Norm Hanley.
10 I'm not sure what table you are referring
11 to.
12 MEMBER SIEBER: Do you have a better
13 reference?
14 MEMBER SHACK: Yes, it's Table 2.2.3-2 and
15 2.2.3-1.
16 MEMBER SIEBER: I knew you had that.
17 (Laughter.)
18 MR. HANLEY: Do you have the title of the
19 table?
20 MEMBER SHACK: "Upper Critical Component
21 Strains Due to FIV, PNB, Units 1 and 2" is the second
22 table. And the first one is, essentially, "Lower
23 Internal Critical Component and Stresses Due to FIV".
24 MR. HANLEY: Yes, we will have to revisit
25 that table and get back to you.

1 MEMBER SHACK: Okay.

2 MR. MEYER: So, just reflecting on this
3 slide, this project is a very exciting package for us.
4 It is a large package. It is a safer plant, a better
5 plant for the operators, more reliable, and resolving
6 a number of legacy issues, such as the 480-volt
7 loading I described.

8 MEMBER SIEBER: Could you say a couple of
9 extra words about more operational margin?

10 MR. MEYER: Yes.

11 MEMBER SIEBER: It seems to me like, when
12 you raise the temperature and increase the flow, lower
13 the relief valve setpoints, which I think you did,
14 that the margins are going down, not up.

15 MR. MEYER: Yes, what I mean by that, sir,
16 is we have already taken all of the modifications and
17 we have modeled them on our simulator with a lot of
18 precision.

19 MEMBER SIEBER: You mean this is an
20 operator simulator?

21 MR. MEYER: Correct.

22 MEMBER SIEBER: Oh, okay. So, from an
23 operating standpoint, you feel like you have more
24 margin?

25 MR. MEYER: Yes.

1 MEMBER SIEBER: But from an engineering
2 standpoint --
3 MR. MEYER: Our team will be going over
4 those various margins as we proceed through the day.
5 MEMBER SIEBER: Because when you make the
6 conditions more severe and use the same equipment, to
7 me, that is a reduction in margin.
8 MR. MEYER: Okay. Next slide, please.
9 So, I just want to chat a little bit about
10 the actual project itself from a site perspective. It
11 is a sitewide initiative. It is a very integrated
12 approach. We have hired who we feel are the best of
13 the best. We have got Westinghouse Bechtel is the
14 construction firm, and Bechtel is the original AE for
15 the plant. Thus, from an engineering point of view,
16 we have Shaw, who is been involved in many, many
17 uprates, and Sargent and Lundy. So, we have
18 surrounded ourselves with a strong team.
19 That entire engineering organization,
20 though, it is important from an integration
21 perspective, reports to my Site Engineering Director.
22 We did not want it to be a separate thing going on at
23 the site. We wanted it to be fully integrated with
24 site operations.
25 And so, engineering reports up through my

1 Site Engineering Director. And at any one time, we
2 have between five and ten of our most experienced
3 senior reactor operators in the project reviewing
4 projects, reviewing work packages, reviewing margins
5 to make sure that we get a better plant.
6 We have done an awful lot of work already.
7 For example, installation of the new auxiliary
8 feedwater system, the piping, all of the cables, and
9 some other work activities we have done with our
10 Bechtel construction firm, over 2 million per-hours of
11 work in the field, injury- and event-free, with that
12 work being done online.
13 MEMBER SIEBER: What are the bottom-line
14 determinations made with that event?
15 MR. MEYER: Pardon me?
16 MEMBER SIEBER: The bottom line there?
17 MR. MEYER: What that is is part of our
18 new auxiliary feedwater system. So, we have got the
19 motors and the pumps that are installed in our
20 auxiliary building.
21 MEMBER SIEBER: So, you are talking about
22 electrically termination?
23 MR. MEYER: Exactly. We run all the
24 electrical cables down there.
25 MEMBER SIEBER: The title above it was

1 "Site Personnel".

2 (Laughter.)

3 Okay. Thank you.

4 MR. MEYER: Yes.

5 We have spoken to this somewhat. We have

6 had very extensive involvement of our own station

7 engineers and our operators in ensuring that we

8 maintain or improve our margins.

9 The new main feedwater pumps and

10 condensate pumps provide increased margins for

11 secondary transients. We have an increased flow

12 margin with the new aux feedwater pumps.

13 And we have some other benefits as well

14 that we will be going through as we proceed.

15 MEMBER SIEBER: Yes, your feedwater flow

16 had to go up by about 18 percent above the original

17 plant design. That is why you replaced it, right?

18 MR. HALE: Yes.

19 MEMBER SIEBER: Okay. So, you have

20 additional margin beyond the minimum it would have

21 taken just to meet the flow demand?

22 MR. HALE: Correct.

23 MEMBER SIEBER: Okay.

24 MR. HALE: Correct.

25 MEMBER SIEBER: And that would mean that

1 you could actually run with feedwater heaters out of
2 service, which usually increases the heat flux.
3 MR. HALE: Correct.
4 MEMBER SIEBER: Correct?
5 CHAIRMAN BANERJEE: Is there any change in
6 the piping around the LEFMs?
7 MR. HALE: No.
8 MEMBER SIEBER: The same pipe.
9 CHAIRMAN BANERJEE: Okay. We will come
10 back.
11 MEMBER SIEBER: Yes.
12 MR. MEYER: I will touch on a related
13 point in a moment.
14 But I would like to say that our license
15 amendment request was prepared utilizing the guidance
16 of RIS-001 and that we have addressed lessons learned
17 from previous extended power uprates, such as Ginna.
18 Because of the changes in the plant
19 brought about by uprates, such as higher steam flows
20 through the pipes that you were just talking about, we
21 factored the changes into our license renewal program.
22 For example, higher steam flow rates on the secondary
23 side have been modeled into our flow-accelerated
24 corrosion program. As a result, that will drive
25 changes to inspection periodicities and things of that

1 nature. So that it is all tied together with our
2 aging management program.
3 MEMBER SHACK: You were on your TLAAs
4 there, and I had a question on your leak before break
5 analysis, which you mention that you have accounted
6 for the thermal aging in your cast elbows as part of
7 the TLAA for the license renewal. Was that actually
8 based on a time and temperature extrapolation or you
9 used some sort of lower-bound toughness for that, so
10 it wouldn't be affected by the EPU?
11 MR. HALE: I think we used the
12 time/temperature, didn't we?
13 MR. HANNEMAN: This is Harv Hanneman from
14 NextEra Point Beach.
15 Yes, we evaluated the leak before break
16 analysis that was done not only the main reactor
17 coolant piping, but on the auxiliary lines connected
18 to the reactor coolant piping, and determined that the
19 uprate conditions really did not affect the design
20 analysis that was done.
21 MEMBER SHACK: Because you had used the
22 lower boundings rather than trying to --
23 MR. HANNEMAN: Yes, that's correct. Right.
24 MEMBER SHACK: -- actually extrapolate an
25 aging?

1 MR. HANNEMAN: Right. And the cold leg
2 temperatures do not change very much because we are
3 raising T av and raising the delta T in the primary
4 system. So, it really doesn't -- the leak before
5 break analysis was bounding for the EPU conditions.
6 MEMBER SHACK: How long have you had the
7 152 inlays on the dissimilar metal welds? Are those
8 with the new steam generators?
9 MR. HANNEMAN: Yes, those are part of the
10 steam generator replacements that were done in 1983
11 for Unit 1 and 1996 for Unit 2.
12 MEMBER SHACK: They actually did that in
13 1983?
14 MEMBER SIEBER: Yes, the first one.
15 MEMBER SHACK: No, I meant the steam
16 generator replacement, I am a little surprised they
17 did the overlay.
18 MEMBER SIEBER: Yes, because that was not
19 as big a scare.
20 MR. HANNEMAN: I think that might have
21 only been on the Unit 2 generators that we replaced in
22 1996, yes.
23 MEMBER SHACK: Now is there a dissimilar
24 metal weld, then, on the Unit 1 generators?
25 MEMBER SIEBER: There's got to be.

1 MEMBER SHACK: I mean a nickel. There is
2 obviously a dissimilar metal weld.
3 MR. HANNEMAN: We would have to find out
4 the answer to that question. I don't know off the top
5 of my head.
6 MEMBER SIEBER: You are the metallurgist.
7 But I always worry when we get above about 608
8 because that is where the knee is in the curve for
9 alloy 600.
10 MEMBER SHACK: Well, they haven't got any
11 alloy 600 left.
12 MEMBER SIEBER: Oh, okay.
13 MEMBER SHACK: Well, except maybe for this
14 weld.
15 MEMBER SIEBER: That's why we need to
16 know.
17 MEMBER SHACK: Well, I guess they have
18 some bottom penetration nozzles, too, but those are
19 pretty cool.
20 CHAIRMAN BANERJEE: Can you put that down
21 as an action to have addressed?
22 MR. HANNEMAN: Steve, I believe there is a
23 discussion on the alloy 600 later in the presentation,
24 isn't there?
25 MR. HALE: Yes. Yes, I believe there is.

1 MR. HANNEMAN: So, we will pick up this
2 discussion later, and we will try to find the answer
3 to your one question on the weld overlay on the Unit 1
4 steam generators.
5 MEMBER SIEBER: Even though your
6 pressurizer temperature isn't changed because the
7 reactor coolant pressure is the same, typically, they
8 are either on heater sleeves or relief valve couplings
9 or surge line or maybe alloy 600, and if you could let
10 us know within the next couple of days whether you
11 have any of that, that would be --
12 MR. HANNEMAN: As I said, we will discuss
13 that later in the presentation.
14 MR. HALE: But we are an older
15 Westinghouse plant. So, we didn't use quite as much
16 of the alloy 600 instruments connections. Most of
17 those were stainless.
18 MEMBER SIEBER: You did not use?
19 MR. HALE: Yes. Yes, the older plants,
20 typically, Westinghouse older plants did not use as
21 much as the alloy 600 as some of the later plants did.
22 I think some of you all that have gone through
23 license renewal have seen that, but a lot of the older
24 Westinghouse plants use stainless for their instrument
25 connections.

1 MR. MEYER: That concludes sort of an
2 overview, background history. I appreciate the
3 opportunity to provide that, and I will turn it over
4 to Mr. Steve Hale to talk a little bit more about the
5 modifications and unique features of the standard
6 uprate.
7 CHAIRMAN BANERJEE: Thank you.
8 MR. HALE: What I thought I would do is
9 summarize the changes in the parameters, give a brief
10 overview of technical specification changes we are
11 adopting a number of codes, new codes, and our
12 analyses and safety evaluations, and run through the
13 modifications we're implementing.
14 Go to the next one, Jay.
15 Selection of the power level. I was
16 involved with the feasibility study. We had a number
17 of vendors involved with it as well.
18 We thought we would go with what the other
19 two loops have done. Typically, the two-loop plant
20 from a PWR perspective had a lot more margin. I
21 usually call them a four-loop plant in two-loop
22 clothing. So, there is a lot of margin typically
23 built into the two-loop plants.
24 And we looked at Ginna and we looked at
25 Kewaunee. We looked at the final power level that

1 both of those plants went to. We are actually
2 consistent with the analyzed power level with Ginna.
3 They do not have an LEFM. So, their uncertainty,
4 power uncertainty, is greater. But if you look at the
5 analyzed power level, we are consistent with Ginna.
6 CHAIRMAN BANERJEE: Is that taking 2
7 percent on --
8 MR. HALE: Yes, theirs is 2 percent. If
9 you put 2 percent on top of the 1775, you will get to
10 what we analyzed at, which was 1811, and 2 percent on
11 top of theirs will get you that same analyzed power
12 level.
13 MEMBER SIEBER: You've reduced that to
14 what, about .6?
15 MR. HALE: .6. It's .6 percent.
16 CHAIRMAN BANERJEE: That's your current
17 MUR?
18 MR. HALE: Yes.
19 CHAIRMAN BANERJEE: .6 percent?
20 MR. HALE: Yes, that is our current power
21 uncertainty, right. And it is with, I don't know, the
22 company has changed names several times.
23 CHAIRMAN BANERJEE: Caldon.
24 MR. HALE: Yes, Caldon. I think it has
25 changed to Cameron.

1 CHAIRMAN BANERJEE: Cameron.

2 MR. HALE: It's changed three times, so it

3 is hard to keep track.

4 CHAIRMAN BANERJEE: Okay.

5 MEMBER SIEBER: Now there are differences

6 between Point Beach and Ginna. They are modest,

7 though. They are in vessel sizes and flow rates and

8 things like that. But, basically, you are modeling

9 after Ginna?

10 MR. HALE: Essentially, yes. In fact, our

11 contractors got tired of hearing us say, "What did

12 Ginna do?"

13 MEMBER SIEBER: You are at higher

14 temperatures than Ginna is.

15 MR. HALE: Yes.

16 MEMBER SIEBER: By a couple of degrees.

17 MR. HALE: Yes.

18 MEMBER SIEBER: And you are getting a

19 couple more megawatts.

20 MR. HALE: Yes. Yes, from the fact that

21 our power uncertainty is higher, I mean lower.

22 Okay. This is just a summary of the

23 parameters. As is typical when you do one of these

24 major safety analyses with the investment that you put

25 into it, you do want to evaluate a range. This is

consistent with Westinghouse's approach --

CHAIRMAN BANERJEE: Let me just ask you, of course, the power uncertainty impacts the LOCA analysis. I noticed you have used ASTRUM.

MR. HALE: Yes.

CHAIRMAN BANERJEE: Did Ginna use ASTRUM, too?

MR. HALE: I cannot answer that question.

MR. DOMINICIS: My name is Dave Dominicis. I'm from Westinghouse.

I don't believe Ginna used ASTRUM. I think they were pre-ASTRUM.

MEMBER SIEBER: That's right.

MR. DOMINICIS: I'm not positive about that. Is that true, Kevin?

MEMBER SIEBER: I think so.

MR. DOMINICIS: Yes, that is true. They did not use ASTRUM. They used an earlier version. Oh, they did use ASTRUM. I'm sorry.

CHAIRMAN BANERJEE: Okay. Because, otherwise, I can't see how you can do this because ASTRUM gains you about 200 degrees, right, in PCT, roughly?

MR. DOMINICIS: We have the LOCA analyst that did the BE LOCA for --

1 MR. BARBER: I didn't quite hear the
2 question. Could you repeat it?
3 CHAIRMAN BANERJEE: I was just saying, if
4 they didn't use ASTRUM, I would be surprised how they
5 could operate with a 2 percent uncertainty at 1775
6 because it is only with ASTRUM that you get down below
7 2,000 degrees, right? Otherwise, with the PCT, you
8 would be over probably.
9 MR. BARBER: Yes, this is Kevin Barber
10 from Westinghouse.
11 Yes, what you are saying is essentially
12 correct.
13 CHAIRMAN BANERJEE: Right.
14 MR. BARBER: Different methodology
15 essentially is the benefit most of the time for PCT.
16 CHAIRMAN BANERJEE: Okay. Well, we will
17 go back and explore this, of course.
18 MR. HALE: Yes, we intend to go over LOCA.
19 We will go over LOCA. Jay will be addressing LOCA
20 and small-break LOCA and non-LOCA events.
21 So, this summarizes the parameters. We do
22 evaluate a range of T av to look at and be able to
23 accommodate things like coastdown, but, also, any
24 changes we may make in the future, you want to make
25 sure that you are bounded by your analysis.

1 DR. WALLIS: Wetter steam increases
2 erosion, does it?
3 MR. HALE: Yes, you have, when you look at
4 moisture carryover, your turbine vendor has specific
5 limits that he specifies at the turbine throttle
6 valves.
7 DR. WALLIS: Does he extract moisture
8 probably through the turbine?
9 MR. HALE: Well, it will affect turbine
10 performance and reliability. So, in order to achieve
11 the turbine vendor's requirements at the turbine
12 throttle valves, you need to be less than a quarter
13 percent moisture at the discharge of the steam
14 generators.
15 CHAIRMAN BANERJEE: So, these are the new
16 HP turbines?
17 MR. HALE: Yes.
18 CHAIRMAN BANERJEE: Right.
19 MR. HALE: Yes. Actually, we are
20 replacing the steam path --
21 CHAIRMAN BANERJEE: Okay.
22 MR. HALE: -- the rotating and fixed
23 blades; the actual shell itself will remain.
24 CHAIRMAN BANERJEE: Okay.
25 MR. HALE: But we are basically replacing

1 the internals of the HP.

2 CHAIRMAN BANERJEE: Who makes the

3 turbines?

4 MR. HALE: Siemens. Originally,

5 Westinghouse, but now Siemens.

6 DR. WALLIS: They get wetter because the

7 higher velocity entrains more droplets? Is that why

8 there is so much more moisture carryover?

9 MR. HALE: Essentially.

10 DR. WALLIS: And this is a prediction?

11 MR. HALE: Yes.

12 DR. WALLIS: From somebody's correlation

13 or something?

14 MR. HALE: Well, Westinghouse has analyzed

15 and has different calculations that they performed,

16 but it has been baseline and against actual test data.

17 DR. WALLIS: So, it is related to real

18 data?

19 MR. HALE: Yes, yes, yes, it is.

20 CHAIRMAN BANERJEE: So, it is a

21 measurement of the quality, I guess, in some way?

22 MR. HALE: Yes. Right.

23 CHAIRMAN BANERJEE: Well, how do they

24 measure the quality?

25 MR. HALE: Actually, I oversaw this

1 testing at Seabrook. You have got to have a source.
2 You get a radioactive source, and it is actually
3 tracer testing, they call it.
4 MEMBER SIEBER: That's one way to do it.
5 MR. HALE: Yes.
6 CHAIRMAN BANERJEE: Okay.
7 DR. BONACA: Excuse me. I have a question
8 -- oh, I'm sorry -- regarding the detail. In the
9 text, it says that the surge line temperature has not
10 changed. But your hot leg temperature has gone up.
11 MR. HALE: It may have to do with the
12 analysis temperature of the surge line.
13 DR. BONACA: No, I don't understand.
14 MR. HALE: Well, the actual temperature
15 that the surge line experiences. I'm not sure where
16 you are referencing where the surge line temperature
17 is going up.
18 MR. DOMINICIS: This is Dave Dominicis
19 again.
20 It may be that the temperature that the
21 surge line was originally designed for compared to
22 what it is actually seeing with the EPU, because it
23 was probably designed for a higher temperature, and
24 now the EPU is maybe closer to that higher
25 temperature --

1 MR. HALE: But still within the design.
2 MR. DOMINICIS: -- but still within the
3 design.
4 DR. BONACA: Yes, I was trying to
5 understand the pressurizer program. You know, it
6 essentially goes from the maximum to the minimum level
7 in the pressurizer. That has changed.
8 MR. HALE: Yes.
9 DR. BONACA: Okay. And so, you have
10 implemented that?
11 MR. HALE: Yes, and it is typically based
12 on your margin trip analysis and evaluations, and you
13 want to ensure that your level, you know, you can
14 accommodate, anticipate the plant transients, you
15 know, without --
16 DR. BONACA: Okay. So, that was done
17 then?
18 MR. HALE: Yes.
19 DR. BONACA: And most of all, they want to
20 verify that the pressurizer is not empty?
21 MR. HALE: That is correct. You don't
22 want it to empty and you don't want it to fill.
23 DR. BONACA: Right.
24 MR. HALE: Yes.
25 DR. BONACA: Okay.

1 MR. HALE: And so, you look at pressurizer
2 level and make design adjustments based on looking at
3 various plant transients.
4 MEMBER SIEBER: Now, on your turbine, it
5 seems to me I read that you have modified the high-
6 pressure section?
7 MR. HALE: Yes.
8 MEMBER SIEBER: But your moisture
9 carryover is two and a half times what it was before
10 EPU, according to your chart there.
11 MR. HALE: Yes.
12 MEMBER SIEBER: Have you done anything to
13 the low-pressure section to avoid erosion of the tail-
14 end of the turbine?
15 MR. HALE: Well, that is really where the
16 criteria from the turbine vendor -- you know,
17 typically, we have a lot of margin with regards to
18 moisture carryover.
19 MEMBER SIEBER: Okay.
20 MR. HALE: As you can see, we are like at
21 .1, but even now, the limit at the HP, which
22 corresponds to what your limits will be downstream, is
23 .5. So, as long as you can achieve the .5, and
24 Siemens has evaluated the LPs relative to that, that
25 we will have sufficient capability --

1 DR. WALLIS: And you probably extract
2 water from the high-pressure turbine.
3 MR. HALE: Well, you run through the MSRs.
4 After your HP, the steam gets routed through MSRs and
5 back to the LPs.
6 MEMBER SIEBER: You would hope that it
7 would end up dry --
8 MR. HALE: Right, right.
9 MEMBER SIEBER: -- at that point, but
10 things happen in the MSRs also.
11 MR. HALE: Right. Understood.
12 MEMBER SIEBER: Now you have done a lot of
13 turbine overhauls where you had the low-pressure
14 sections opened in the past.
15 MR. HALE: Yes.
16 MEMBER SIEBER: Have you seen erosion,
17 particularly on the last three or four rows of
18 rotating blades? I presume they are stellite-tipped.
19 MR. HALE: Yes, it is a fairly standard
20 Westinghouse --
21 MR. HANNEMAN: Yes, this is Harv Hanneman
22 from NextEra.
23 We replaced the low-pressure turbine
24 rotors in around 1997. The turbines were actually
25 designed for a slightly smaller power uprate, about a

1 10 percent power uprate, at that time.

2 MEMBER SIEBER: Yes, I understand. That's

3 why I'm asking the questions.

4 MR. HANNEMAN: And the new turbines had a

5 10-year maintenance overhaul. Each turbine has been

6 opened up since then and we saw no evidence of erosion

7 or any problems.

8 MEMBER SIEBER: Well, you can actually see

9 some. You know, it gets sort of grainy right behind,

10 if it is stellite-tipped, it will grainy right at that

11 joint. It doesn't take too long for that to form.

12 But, generally, it will stabilize at that point unless

13 the moisture is too high.

14 But I have seen the strips come off or

15 separate from the blade. Have you seen anything like

16 that?

17 MR. HANNEMAN: The inspection reports

18 indicate there's no unexpected degradation --

19 MEMBER SIEBER: Okay, and you have had no

20 cracking of the lash wires between the blades? You

21 know, that is where they are welded to give it

22 stability.

23 MR. HANNEMAN: We haven't seen that.

24 MEMBER SIEBER: Okay.

25 MR. HALE: If we move to the next slide

1 there, Jay?

2 Looking at the BOP, we did go through --

3 you know, you have got some critical parameters you

4 want to ensure that you can meet. There is a lot of

5 OE out there that says that, if you miss on your

6 turbine inlet pressure, that you are in serious

7 trouble in terms of design. So, you want to make sure

8 you nail the critical parameters.

9 MEMBER SIEBER: Okay.

10 MR. HALE: We did do baseline testing to

11 validate our heat balances at the current power level.

12 We have actually done testing at the current power

13 level, so that we have better confidence in our

14 forecast as to what we anticipate the performance to

15 be at the new uprated power level.

16 And in addition to that, we have looked at

17 the typical hydraulic analyses that you perform, loss

18 of a condensate pump, loss of a feed pump, and

19 evaluated relative to those new parameters.

20 DR. WALLIS: Does this include water

21 hammer in the feedwater or aux feeds?

22 MR. HALE: Water hammer, typically, in aux

23 feedwater we don't have water hammer issues. That is

24 a cold water system. In the feedwater system, I don't

25 think we have experienced water hammer issues. I know

1 early in design, if you had a long, horizontal run of
2 feedwater piping into your steam generator, it could
3 typically cause -- our configuration is good from that
4 standpoint. So, we really haven't seen major issues
5 with feedwater hammer.
6 DR. WALLIS: It doesn't change with the
7 EPU?
8 MR. HALE: No. No, not what we would
9 anticipate in terms of any feedwater hammer effects.
10 MEMBER SIEBER: Now your generator will
11 produce more power, obviously, because you are getting
12 a power uprate. It would seem to me that you have
13 made modifications to the generator.
14 MR. HALE: Yes. I will talk about that,
15 okay?
16 MEMBER SIEBER: Okay.
17 MR. HALE: I wanted to run through the
18 parameters and the tech spec changes, and then I will
19 get into the actual hardware. But this was really
20 just summarizing how we set the stage, basically, for
21 the design evaluation of the secondary equipment.
22 I thought I would quickly summarize the
23 tech specs. I will get into the details of the actual
24 modifications. First, let me talk about the related
25 license amendments.

1 We do have ASTRUM. That was approved by
2 the NRC separately. So, we have an approval of use of
3 the ASTRUM methodology.
4 Our Alternate Source Term License
5 Amendment, it is really near in final form. I think
6 it is getting real close to being routed internally in
7 the NRC's house for approval.
8 Our original LAR had the AWF and the
9 RPS/ESFAS as part of the EPU LAR. Because those
10 amendments were critical to improving safety at the
11 plant, they were really segregated by the staff as
12 separate license amendments, but they were really a
13 part of the original EPU. So, I will get into, when I
14 discuss the tech specs and the mods, I will be talking
15 about both AWF and RPS/ESFAS.
16 MEMBER SIEBER: Have you gotten your
17 Alternate Source Term yet?
18 MR. HALE: No, it is very close, though.
19 The staff will have to -- I think Terry had indicated
20 that it is pretty near to be routed for concurrence.
21 MEMBER SIEBER: Now the captured source
22 term in the containment after an accident would go up
23 by, basically, the EPU power level. Your containment
24 is atmospheric containment, right?
25 MR. HALE: It is a standard Bechtel post-

1 tension containment, yes.

2 MEMBER SIEBER: Okay. That is basically

3 atmospheric.

4 MR. HALE: Right.

5 MEMBER SIEBER: Did you need the Alternate

6 Source Term due to Part 100 or it is just an added

7 feature?

8 MR. HALE: Probably our tightest margin

9 was control room dose.

10 MEMBER SIEBER: Okay. That's not

11 surprising.

12 MR. HALE: And even under our current

13 license basis, when Larry was talking about legacy

14 issues, in order to meet our dose requirements for

15 control room, we have to dispense potassium iodide.

16 MEMBER SIEBER: Okay.

17 MR. HALE: So, the AST not only allows us

18 to accommodate the EPU, but it also allows us to not

19 have to dispense potassium iodide to operators in

20 order to achieve our dose requirements.

21 MEMBER SIEBER: Yes. Okay. Okay. Go

22 ahead.

23 MR. HALE: Moving on to the tech spec

24 changes, as Terry Beltz had mentioned, we have gone

25 through, I'll call it, a major upgrade to RPS/ESFAS

1 setpoints. Not only do we have the EPU changes, but
2 we have also modified our non-EPU changes.
3 Again, pointing towards one of these
4 legacy issues, we did not have a rigorous uncertainty
5 analysis for our RPS/ESFAS setpoints. We have adopted
6 that rigorous methodology. And following the TSTF-493
7 Rev. 4 guidance, we have adopted tech specs that
8 include not only an allowable value, but also nominal
9 trip setpoint into the actual tech specs, plus
10 specific directions on what you do for as-count and
11 as-left conditions. So, this is a significant upgrade
12 to the tech specs in the area of the RPS/ESFAS
13 setpoints.
14 MEMBER SIEBER: Okay.
15 MR. HALE: Talking about AFW, and I will
16 get into some of the design details later, so if you
17 have questions regarding that, you could defer them
18 until I get into the description of the mod?
19 Certainly, when you make a major change to
20 a system like AFW, there will be a number of AFW tech
21 specs that are changed as a result of that. This just
22 summarizes some of them.
23 We are reducing, as you can see, our
24 allowed out-of-service time from currently, which is
25 seven days, to 72 hours. We are making changes to the

1 system, such that we have an auto switchover to the
2 safety-related suction source, so there is a new ESFAS
3 setpoint. And, of course, as a result of the
4 increased heat loads, you have changes in your
5 condensate storage tank levels.
6 Looking at the other tech spec changes,
7 most of these are related to core and power
8 distribution limits and that sort of thing, which you
9 would expect to see with an uprate of this magnitude.
10 Dr. Bonaca mentioned the pressurizer water
11 level increase. We are changing that. That is also
12 to address certain margins.
13 And, then, we have got changes. We are
14 changing two of the main steam safety setpoints, not
15 all of them, but two of the main steam safety valves
16 to a lower setpoint. But, overall, the lift setpoint,
17 you know, where the initial valves lift, is the same,
18 but we are just reducing two of them. We had three-
19 tier, and now we have reduced two of them to the
20 initial tier.
21 MEMBER SIEBER: And why are they reduced?
22 MR. HALE: Because what you find is some
23 of the transients --
24 MEMBER SIEBER: Because the pressure goes
25 up.

1 MR. HALE: Yes. If you look at the
2 transients, the overpressure events, you know, for an
3 uprate of this magnitude is where you really get into
4 some detected margin.
5 MEMBER SIEBER: So, you would either
6 reduce the setpoint or leave the setpoint alone and
7 change the valve to increase the capacity?
8 MR. HALE: Yes, you could do one or the
9 other.
10 MEMBER SIEBER: You want to put a new
11 valve on?
12 MR. HALE: Right. Right.
13 MEMBER SIEBER: I got it.
14 MR. HALE: And, then, again, we mentioned
15 the new feedwater isolation valves. These are fast-
16 acting valves that close in five seconds. And as you
17 might imagine, they will be new tech specs associated
18 with those.
19 Looking at code and methodology changes,
20 we are adopting several new codes. I think the
21 important message, these are all pre-approved codes
22 and methodologies. You know, the NRC has approved,
23 and these are just first-time applications for Point
24 Beach.
25 CHAIRMAN BANERJEE: So, when you say every

1 time you had a question, what did Ginna do, is this
2 more or less in line with what Ginna did? I wasn't
3 involved in Ginna, but I think Jack was.
4 MR. HALE: In some cases, where there will
5 be differences, but I would say we are fairly
6 comparable in terms of the Westinghouse analyses that
7 were performed.
8 CHAIRMAN BANERJEE: Correlations for the
9 DNB and all this stuff?
10 MR. HALE: Yes, they are typically very
11 similar to --
12 CHAIRMAN BANERJEE: So, at some point,
13 maybe Westinghouse, when it goes into the analyses,
14 can point out if there are differences.
15 MR. HALE: Okay.
16 CHAIRMAN BANERJEE: They did most of the
17 analysis, correct?
18 MR. HALE: Yes, yes. Westinghouse, of
19 course, did Ginna, and they also did our analysis.
20 CHAIRMAN BANERJEE: Right.
21 MR. HALE: In fact, we had some of the
22 same people, as you have heard, involved with both
23 efforts. I would say, generally, we will get into
24 some plant-specific stuff.
25 I know, then, in our loss-of-flow and

1 locked rotor analysis, where we used RAVE, we had made
2 an assumption on a number of failed fuel assemblies,
3 and RAVE helped us support a reduced number of failed
4 fuel assemblies. So, that may be specific to us. I'm
5 not sure.
6 CHAIRMAN BANERJEE: Okay. You can point
7 it out to us at that point.
8 MR. HALE: Okay.
9 DR. WALLIS: Why do you use RETRAN?
10 MR. HALE: I think it is a better code
11 from the standpoint of evaluating a non-LOCA
12 transient.
13 MEMBER SHACK: This is not RETRAN 3D.
14 MR. HALE: Yes.
15 DR. WALLIS: Oh, it's not? It's not the
16 new RETRAN?
17 MR. HALE: No.
18 DR. WALLIS: This is the ancient RETRAN?
19 MR. HALE: And you have got to realize
20 that a number of the codes that Point Beach utilized
21 were very old. So, this was an opportunity for us to
22 update our analyses.
23 I mean, when you are looking at the
24 investment, it is significant when you reanalyze all
25 these events. So, you want to make sure you get it

1 right.

2 CHAIRMAN BANERJEE: One of the things you

3 are doing is, of course, using codes as well in place

4 of doing some testing, right? I noticed that.

5 MR. HALE: We talked a little bit about

6 large transient testing, and we will get into that

7 when we talk about power ascension.

8 CHAIRMAN BANERJEE: You used LOFTRAN?

9 MR. HALE: Yes, we used some of the

10 projections with LOFTRAN and used some of the

11 information that occurred at Ginna where they actually

12 baselined --

13 CHAIRMAN BANERJEE: So, it would be useful

14 to see how LOFTRAN did against the large transients.

15 MR. HALE: Yes, we actually provided some

16 of that information, I believe, on the docket, based

17 on what they saw at Ginna versus what was predicted.

18 DR. WALLIS: What do you use to predict

19 the strain of blockage following a LOCA? Is there a

20 method?

21 CHAIRMAN BANERJEE: No, it's just testing.

22 DR. WALLIS: It's just testing? It's all

23 based on specific testing for -- do you want to talk

24 about that later?

25 MR. HALE: I am not sure if we have got

1 the actual --

2 CHAIRMAN BANERJEE: They haven't resolved

3 GSI-191.

4 DR. WALLIS: They haven't resolved that,

5 yes, I know.

6 CHAIRMAN BANERJEE: Yes, they are in the

7 RRT process.

8 DR. WALLIS: So, GSI-191 is off the table

9 today, is it?

10 MR. HALE: We plan to talk about it. I

11 think what is important to note, that all of our

12 evaluations and analyses for GSI-191 took into account

13 the EPU. So, all the stuff that we --

14 DR. WALLIS: It doesn't change it very

15 much, though.

16 MR. HALE: No.

17 CHAIRMAN BANERJEE: Well, what it would do

18 is, of course, change the temperatures.

19 MR. HALE: Yes.

20 CHAIRMAN BANERJEE: Which means that the

21 effect would be on the NPSH of the pumps. So, the

22 real issue is, would you need some containment

23 overpressure? We will go through this.

24 MR. HALE: We can talk about that, right.

25 We will get to it.

1 CHAIRMAN BANERJEE: Probably that would be
2 something we want to make sure that there is no really
3 significant adverse effect.
4 MR. HALE: Understood.
5 CHAIRMAN BANERJEE: Yes.
6 MR. HALE: Understood.
7 With regard to a high-energy line break
8 outside containment, again, this is one of those long-
9 term issues at Point Beach in that we didn't have good
10 documentation of our energy line break analyses. You
11 know, we couldn't get our hands on the specific design
12 basis information and that sort of thing.
13 So, we took it upon ourselves to update
14 our HELB analysis as part of this EPU, so that we have
15 a good, fundamental bases for our design and the
16 evaluations that we perform.
17 CHAIRMAN BANERJEE: You are going to go
18 through this in some detail at some point?
19 MR. HALE: Yes, I believe the staff is
20 actually going to get into some details in
21 summarizing.
22 CHAIRMAN BANERJEE: Yes, yes.
23 MR. HALE: We just thought what we capture
24 here is that we did go back and redo all of our
25 calculations. We adopted some of the later

1 methodologies in terms of how you determine break
2 locations. It was kind of a hybrid between our
3 current licensing basis and adopting some of the new,
4 better approaches to HELB analyses that the other
5 codes had limits associated with.
6 I think the bottom line is we didn't
7 change any of our mitigating features as a result of
8 the analysis or evaluations, and we did address, you
9 know, we actually have a GOTHIC code for all the
10 areas, so we can address EQ from a temperature and
11 pressure standpoint. And there were some slight
12 changes in the EQ area as a result of the effort.
13 MEMBER SHACK: Well, I did find that very
14 confusing as I tried to read through that, partly
15 because I couldn't get my hands on a 1977 version of
16 the code.
17 The acceptance criteria, I thought I could
18 understand most. Did you develop that acceptance
19 criteria or is that acceptance criteria from somewhere
20 else, like the 1977 code?
21 MR. HALE: It is acceptance criteria. We
22 adopted the acceptance criteria that was in the `77
23 code.
24 MEMBER SHACK: This is the 1.2 SH --
25 MR. HALE: Right.

1 MEMBER SHACK: -- actually is in the code?

2 MR. HALE: Yes. The staff did a very

3 detailed review of what we performed. In fact, they

4 came to the site for a site audit. And we provided

5 them all of our backup information, which you can

6 imagine could fill this table probably, but it was

7 quite an effort. I think that we are better from it

8 and we have got a good documentation and background of

9 our HELB analysis now that we didn't have before.

10 DR. BONACA: I would like to go back to my

11 comment on the licensing basis for the plant. When I

12 went through the SER, and looking at the discussion,

13 there are the conditions of specific exceptions for

14 certain areas. For example, single failure I will

15 assume is all in this report. I'm not challenging

16 that.

17 But I found that it is just piecemeal. It

18 is described a piece here and there, depending on the

19 analysis you are in. It would be worthwhile for us at

20 some point to understand a little bit, you know, in a

21 few words, what these fundamental differences are in

22 your licensing basis versus the standard licensing

23 basis for more recent plants.

24 CHAIRMAN BANERJEE: Can we take, though,

25 an action item, so that we address this --

1 MR. HALE: Okay.

2 CHAIRMAN BANERJEE: -- before the end of

3 the Subcommittee meeting.

4 MR. HALE: Okay. And, then, on the next

5 slide, a couple of other areas that we looked at. We

6 looked at post-LOCA operator dose. We have been able

7 to reach a point where operators do not have to leave

8 the control room to access vital areas post-accident,

9 which I think is a positive.

10 And one area is the PASS. This is a

11 methodology that has been adopted and accepted by many

12 other plants. Point beach just hasn't done it yet.

13 But there is a methodology that allows you to assess

14 core damage by looking at various parameters rather

15 than physically having to go out and take a sample

16 three hours after the accident.

17 And we also, as part of our AST mods, we

18 set up the control room ventilation system such that

19 it all loads on the diesel and operators no longer

20 have to go down to an area where there are some MCCs

21 to actually reinstate power on the control room

22 ventilation system.

23 Moving on to plant modifications, I

24 thought I would categorize these into three areas.

25 One is mods that are directly related to safety

1 improvements at the plant. We did implement some
2 modifications specifically to improve our risk
3 profile. I will summarize what those are. And, then,
4 of course, you have got all the mods that are
5 associated with the actual support power output of the
6 plant.
7 With regard to the auxiliary feedwater
8 system, our current system, basically, has one
9 turbine-driven plant pump per unit and, then, we have
10 two motor-driven pumps that are shared between the
11 units.
12 From a reliability standpoint, it is not
13 the best. You have mentioned some other issues. Fire
14 protections, there was a number of issues associated
15 with the existing auxiliary feedwater system. So, we
16 have taken on to improve this system as part of the
17 overall EPU.
18 In that system, we are actually installing
19 two higher-capacity, motor-driven pumps. And with
20 that, you will have one motor-driven and one turbine-
21 driven for each unit, and they will be unitized. So,
22 no more sharing of the plant.
23 We are going to maintain the existing AFW
24 pumps as standby pumps, which I think is a strong
25 feature. A lot of our units in the fleet have what we

1 call our startup pumps and that sort of thing. What
2 that allows you to do, it allows you to eliminate the
3 normal operating services on your safety-related
4 pumps, so that they are strictly for testing or when
5 you actually need them.
6 DR. WALLIS: So, you have six pumps?
7 MR. HALE: Yes.
8 DR. WALLIS: These two ones will actually
9 service both units, too?
10 MR. HALE: Yes. Yes, I mean they do come
11 into play certainly in your risk, but I think the
12 important thing is they will become your normal
13 operating, daily-use-type pumps for startup and
14 shutdown.
15 DR. WALLIS: There's a room to put them
16 in, these new ones.
17 MR. HALE: Yes. Yes, we actually put them
18 in the auxiliary building as a result of the turbine,
19 yes.
20 MEMBER SIEBER: Will all the pumps -- you
21 will now have three, six, you will have eight pumps?
22 MR. HALE: Hum?
23 MEMBER SIEBER: You will have eight pumps
24 now?
25 MR. HALE: Six pumps.

1 MEMBER SIEBER: Six pumps?

2 MR. HALE: Yes.

3 MEMBER SIEBER: Okay. Yes, that's right,

4 you had two that are shared.

5 MR. HALE: Shared.

6 MEMBER SIEBER: Will they all be in tech

7 specs?

8 MR. HALE: No.

9 MEMBER SIEBER: Okay. That means that the

10 old pumps you could say these are spares or you could

11 also say these are retired in place. Do you intend to

12 maintain them and test them?

13 MR. HALE: Yes. What I was saying is that

14 we intend to --

15 MEMBER SIEBER: But you are not committed

16 to, right?

17 MR. HALE: No. What we intend to use

18 these is for normal operating pumps. These will be

19 pumps that are used for startup and shutdown, and you

20 won't have to use your safety-related pumps any longer

21 for that normal operating usage.

22 MEMBER SIEBER: And your old, steam-driven

23 pumps were basically Terry turbines?

24 MR. HALE: Yes, those we are retaining.

25 MEMBER SIEBER: Yes. Did you ever have

1 problems with overspeed trips, and so forth, with
2 those?
3 MR. HALE: Not anything unusual compared
4 to --
5 MEMBER SIEBER: That is why I asked the
6 question. Because it was usual the people who had
7 those pumps had trouble with overspeeds on occasion,
8 and so forth.
9 MR. HALE: Yes. You may have issues with
10 trip linkage and stuff like that associated with the
11 tripping.
12 MEMBER SIEBER: I am getting the
13 impression that you are saying that you are not any
14 different than the other plants that have them?
15 MR. HALE: That is correct.
16 MEMBER SIEBER: Okay.
17 MR. MILLEN: This is Mike Millen from
18 NextEra. I'm the operations guy.
19 I just would like to add we do intend to
20 keep those pumps in our procedures. We will be able
21 to rely on them because, while they won't have any
22 automatic functions, if the operators needed them in
23 an emergency, they still are powered from the same
24 diesel-backed bus. So, we still do retain the
25 capability of having that additional redundancy in our

1 emergency procedures.

2 MEMBER SIEBER: My advice would be to run

3 them on some kind of a surveillance schedule to make

4 sure that they are still operable. But that is just

5 advice; that is not a requirement.

6 CHAIRMAN BANERJEE: Does that go in our

7 letter?

8 MEMBER SIEBER: No. No.

9 DR. WALLIS: It's in the transcript,

10 though.

11 MEMBER SIEBER: It's in the transcript.

12 CHAIRMAN BANERJEE: It's in the

13 transcripts.

14 MR. MEYER: Larry Meyer again.

15 Regarding the Terry turbines, I have been

16 at the plant for three years, and we haven't had any

17 overspeed trips in that time. I know that,

18 historically, problems with the governors and with the

19 governor valve stem, and one of the problems in the

20 industry was a leakage pass the steam emission valves.

21 MEMBER SIEBER: That's right. You build

22 up moisture there.

23 MR. MEYER: Exactly.

24 MEMBER SIEBER: It would get a flash of

25 hot steam and you would get a big puff through it --

1 MR. MEYER: Yes.

2 MEMBER SIEBER: -- and it would overspeed.

3 And the other thing was the governors.

4 MR. MEYER: Right. So, we have very tight

5 steam emission valves. There is no leakage. You can

6 put your hand on the pipe and it is room temperature.

7 And also, we have the latest material on

8 our governor stems as well as we have got steam traps

9 in the system.

10 MEMBER SIEBER: Okay. Yes.

11 MR. HALE: Moving on, Larry described the

12 benefits on the bus during loss of offsite power

13 events. We have moved the safety-related AFW pumps to

14 the 4160 bus. So, that has provided us some benefits

15 electrically.

16 I think one of the major things that we

17 have accomplished, though, is eliminating several

18 operator actions that are currently required with the

19 system. They are required to manually switch over,

20 once you deplete the CST, to the safety-related

21 service water source. We have automated that

22 operation.

23 Also, the mini-recirc valves on the AFW

24 required operators to actually be stationed to go out

25 to the valves after the air is depleted and actually

1 manually operate the recirc valves. We have increased
2 significantly the air supply to those valves.
3 And, then, we have also, as you might
4 imagine with a shared system, you are required to do
5 some manual manipulation to align the appropriate pump
6 to the appropriate unit. And we have eliminated the
7 need for that as well.
8 So, overall, the AFW system is
9 significantly improved from a standpoint of
10 reliability and availability.
11 Additional modifications we have
12 implemented that improve safety and plant margins. We
13 mentioned the fast-acting main feedwater isolation
14 valves. What this does, and you will see in our
15 discussions later, it actually provides a lower peak
16 pressure in containment after implementation of the
17 EPU.
18 We have actually made some changes to our
19 voltage level relay settings to allow us to better
20 accommodate some of the grid transients.
21 Again, I have described the RPS/ESFAS.
22 And Larry also mentioned the main
23 generator output breakers. That enables us to respond
24 during certain conditions of degraded voltage.
25 MEMBER SIEBER: Who is the system operator

1 there?

2 MR. HALE: ATC.

3 MEMBER SIEBER: Okay. Modifications and

4 changes that we are doing to actually improve the

5 overall plant risk profile: we mentioned the

6 automatic switchover, the safety-related water source,

7 and an additional air supply in the mini-recirc

8 valves.

9 The other items that we wanted to mention

10 are that we have got, besides the AFW, as Larry

11 mentioned, we are installing an air compressor. One

12 of the big contributors to our CDF was the reliance of

13 instrument air on service water. So, providing a

14 self-cooled air compressor, we disconnect that and

15 actually provide a benefit in terms of PRA.

16 And also, we have got an alternate means

17 for RCS depressurization by use of a pressurizer

18 auxiliary spray valve. We have a valve now that has

19 the capability of being operated without the source of

20 instrument air. We have provided those clarifications

21 in the EOPs.

22 Of course, any uprate of this magnitude is

23 going to cause you to have to make some changes to the

24 secondary plant, as you might imagine. In addressing

25 the secondary plant, we looked certainly at capacity,

1 but we also want to ensure that we look at margins, we
2 look at reliability. It is also an opportunity for us
3 to approach and look at replacing existing
4 instrumentation, which, you know, with a plant of this
5 vintage, it gives us opportunities to make some
6 improvements there.
7 We can also look at single failure
8 vulnerabilities. What I mean by that, that means
9 single failure vulnerabilities to plant trips and
10 things of this sort.
11 Material enhancements. I mentioned
12 previously we are looking at replacing the internal
13 materials of our feedwater heaters. I mean, through
14 the replacement of our feedwater heaters, we are
15 installing, and we had a very active system engineer
16 that was involved with our decisions with this, in
17 putting in chrome-moly materials internal to the
18 feedwater heaters, where historically you will see
19 erosion where the steam piping comes into the top of
20 it.
21 And lessons learned from industry
22 experience --
23 DR. WALLIS: How do material enhancements
24 address vibration?
25 MR. HALE: I think, from Norm, we have

1 done a number of support modifications. I am not sure
2 that is directly related to material.
3 DR. WALLIS: That's right, not material --
4 MR. HALE: Right.
5 MR. HANLEY: Norm Hanley from Shaw again.
6 Like for the heaters, we have much larger
7 heater capacity-wise, but we also addressed the
8 vibration in the standards, like the AGI standards of
9 that. So, heaters were brought to the uprate
10 conditions considering the increased flow and the
11 effect of tube vibration, and so forth. So, when we
12 bought the new heaters, we applied new standards.
13 DR. WALLIS: So, it is not the material
14 that does it? It is the design? It is not the
15 material?
16 MR. HANLEY: Oh, no, it is the design.
17 MR. HALE: It is the way the slide is, but
18 yes.
19 MEMBER SHACK: Have you replaced much of
20 the system with chrome-moly materials in the
21 secondary --
22 MR. HALE: Some of the areas that
23 typically create your biggest problems, typically, we
24 would go in and replace it with chrome-moly. Usually,
25 our replacement program typically requires that when

1 we go in and replace it. But you have to kind of do
2 that judiciously. It is a significant change. And if
3 you have got piping that seems to be doing okay, you
4 know, you wouldn't just go out and change it.
5 But our high-velocity areas typically are
6 items that we would go ahead and replace.
7 DR. WALLIS: When you took out the old
8 bins and things, did you notice a lot of FAC or
9 anything?
10 MR. HALE: Yes. Typically, I mean
11 especially in areas with high levels of moisture and
12 velocity. I think what is important is the CHECWORKS
13 code, you know, at least in my experience, and I have
14 been around a long time, from the time when these
15 failures started occurring until where we are now, I
16 think the FAC program is a very effective program. We
17 have a lot of focus on it. We have developed our
18 inspection techniques and mapping and our baselines.
19 DR. WALLIS: When you take out these
20 pieces, do you do feedback back to EPRI about how much
21 it was worn and how that related to CHECWORKS, and so
22 on?
23 MR. HALE: I am not sure about EPRI, but I
24 know that it goes back into our overall program.
25 DR. WALLIS: As a kind of postmortem?

1 MR. HALE: Yes, there is a plan-do-check-
2 act cycle back into the FAC program, if they need to
3 make some adjustments in the CHECWORKS projections and
4 that sort of thing.
5 MEMBER SIEBER: Yes, that is basically the
6 question. I take it you have had erosion failures
7 that CHECWORKS didn't predict?
8 MR. HALE: I'm not aware of --
9 MEMBER SIEBER: Or at least below MINWALL?
10 MR. HANNEMAN: This is Harv Hanneman from
11 NextEra Point Beach.
12 We did have one rupture of a feedwater
13 heater shell --
14 MEMBER SIEBER: Right.
15 MR. HANNEMAN: -- several years ago. That
16 is one of the reasons we are upgrading the materials
17 in the shells of all the new feedwater heaters. But
18 that shell was not part of the CHECWORKS program at
19 the time.
20 MEMBER SIEBER: Right.
21 MR. HANNEMAN: So, we didn't have any
22 prediction on it. We didn't anticipate that rupture
23 at the time. We had no program --
24 MEMBER SIEBER: Well, I guess my other
25 question, just to clarify what that next-to-the-last

1 bullet really means, you have replaced a lot of
2 components and perhaps piping because you needed
3 additional capacity. But did you replace anything
4 solely for the purposes of material enhancements? Or
5 does that just come along with I need a bigger one, so
6 I will get more modern materials?
7 MR. HALE: I mean I think that we had a
8 choice in terms of the materials we put into the new
9 feedwater heaters. Okay?
10 MEMBER SIEBER: Yes, but you would have
11 had to replace the feedwater heater regardless of a
12 material upgrade.
13 MR. HALE: I understand, but there is a
14 premium you pay for the material upgrade.
15 MEMBER SIEBER: Yes, I understand. That's
16 state-of-the-art.
17 MR. HALE: Yes.
18 MEMBER SIEBER: You know, I'm not sure you
19 could buy an inferior feedwater heater from anybody
20 that is reputable.
21 MR. HALE: Not inferior, but you have a
22 choice on whether you go to corrosion-resistant
23 materials or not.
24 MEMBER SIEBER: Yes. Yes, I guess.
25 MR. HALE: I know because I was involved

with the decision on the feedwater heater material, and the vendor actually recommended a different material. We actually chose to go with the more resistant material at a cost premium.

MEMBER SIEBER: Yes. Right. Better stuff costs more.

CHAIRMAN BANERJEE: Go ahead.

MR. TOMASZEWSKI: Dan Tomaszewski from NextEra.

Yes, we did. Really the only case I can think of is the feedwater heaters. There were some piping replacements that were done, in particular, in the vent system and the drain system, where we were reworking the pipes because of the increased vents.

We did make material changes on those solely due to the erosion/corrosion. But, as Steve said, generally, outside those areas, we procured erosion-resistant materials just due to the life cycle management of not wanting to do increased inspections and putting material in that would not require significant inspection in the future.

MEMBER SIEBER: Okay. Thank you.

MEMBER SHACK: What is your pH in those systems?

MR. HALE: I think we run fairly higher pH

1 now because we got rid of all the copper.

2 MEMBER SHACK: Yes.

3 MR. HALE: You know, so you are able to

4 run --

5 MEMBER SHACK: Crank it up.

6 MR. HALE: -- higher pHs. Because I know

7 you used to have to kind of play a fine line, but once

8 you got rid of the copper, you could run higher, so

9 you could get less iron material, I guess.

10 MEMBER SIEBER: When did you get rid of

11 the copper?

12 MR. HALE: Hum?

13 MEMBER SIEBER: When did you get rid of

14 the copper? That must have been years ago, right?

15 MR. HALE: Yes, yes, yes.

16 DR. BONACA: On the single failure

17 vulnerabilities, could you give me an example of what?

18 MR. HALE: You may have a relay that, if

19 it trips, it would trip the plant.

20 DR. BONACA: Yes.

21 MR. HALE: Where you may have an

22 opportunity from a control standpoint to provide some

23 redundancy there.

24 DR. BONACA: Okay.

25 CHAIRMAN BANERJEE: With regard to the

1 lesson learned from industry, is there experience with
2 your steam generators at these higher flow rates on
3 the secondary side?
4 MR. HALE: I have been pretty active
5 myself. I was on the INPO team many years ago on
6 uprates lessons learned and those sort of things. I
7 think the best person we have right now is Ginna's
8 experience with the steam generators.
9 Certainly, there is not a lot of data or
10 information out there.
11 CHAIRMAN BANERJEE: Are they the same sort
12 of vintage as yours --
13 MR. HALE: Yes, yes.
14 CHAIRMAN BANERJEE: -- the steam
15 generators at Ginna?
16 MR. HALE: And Kewaunee. And Kewaunee.
17 CHAIRMAN BANERJEE: But they are very
18 similar? And Kewaunee?
19 MR. HALE: Yes. And if you look at the
20 power levels they are operating at, they are operating
21 currently very close to where we will be operating.
22 CHAIRMAN BANERJEE: Right.
23 MR. HALE: So, I think that is our source
24 of information currently on steam generator
25 performance. And at least from my knowledge, and then

1 talking with our Westinghouse folks, we haven't seen
2 anything significant in terms of additional issues
3 with the steam generators.
4 MEMBER SHACK: Now Ginna has the smaller
5 diameter tubes. How about Kewaunee; are they the big
6 tubes like you have?
7 MR. HALE: I can't speak to Kewaunee. I
8 am not sure.
9 MEMBER SIEBER: The steam generator tubes
10 themselves?
11 MEMBER SHACK: Yes.
12 MEMBER SIEBER: Okay.
13 MR. HALE: Yes, I'm not familiar --
14 MEMBER SHACK: It depends on when you
15 replaced and what you replaced with.
16 MR. HALE: And as you can see, we have
17 different steam generators at Point Beach because of
18 when we replaced.
19 MEMBER SIEBER: Well, I would have been
20 concerned about moisture separators at the top of the
21 steam generators. But I don't recall any major
22 problems with the EPUs with that type of moisture
23 separators.
24 MR. HALE: Yes, they are just like the
25 peerless veins.

1 MEMBER SIEBER: Yes.

2 MR. HALE: You have the centrifugals and

3 then --

4 MEMBER SIEBER: You are going to get some

5 additional erosion, but it is not a vibrational thing

6 in the welds.

7 MR. HALE: Right.

8 MEMBER SIEBER: Welds are required, but

9 they are not critical strength things. It is just to

10 hold it together.

11 MR. HALE: The feedwater ring, external

12 erosion of the feed ring has been some of the

13 operating experience in PWRs.

14 MEMBER SIEBER: In the sparger?

15 MR. HALE: Yes, the sparger that is there,

16 actually, the external steam flow around that, because

17 that typically was not a corrosion risk, I mean from

18 an OE standpoint, we have seen some erosion in there

19 around the J-tubes and things like that.

20 MEMBER SIEBER: You inspect those --

21 MR. HALE: We inspect those.

22 MEMBER SIEBER: -- every what, every other

23 outage or every outage?

24 MR. HALE: Yes, it is on a specified

25 frequency. I can't tell you what that frequency is,

1 but --

2 MEMBER SIEBER: Yes, usually you do one an

3 outage, and they have been the subject of some wear,

4 you're right.

5 MR. HALE: Right, right.

6 CHAIRMAN BANERJEE: So, is Kewaunee the

7 most similar in terms of tube diameter, tube supports,

8 and things like this?

9 MR. HALE: I can't answer that question.

10 I don't know what --

11 CHAIRMAN BANERJEE: Could we get an answer

12 to that?

13 And there have been no vibration issues,

14 no fretting issues, nothing?

15 MR. HALE: No, not with the new steam

16 generators. And I think we have seen similar

17 experience --

18 CHAIRMAN BANERJEE: No, I mean in sort of

19 similar steam generators in uprated conditions.

20 MR. HALE: No. No, we have not seen that

21 kind of thing. I think Westinghouse's experience has

22 been very positive.

23 MEMBER SHACK: Well, your support plates,

24 even a 1983 one, are probably stainless steel, aren't

25 they?

1 MR. HALE: No, I know they are the
2 quatrefoil, I would assume stainless steel support
3 plates. That is what we have at Turkey Point.
4 MR. HANNEMAN: Yes, Harv Hanneman from
5 NextEra.
6 Yes, even the Unit 1 steam generator
7 replacements had stainless steel.
8 CHAIRMAN BANERJEE: Are there broach
9 plates? What is the support --
10 MR. HALE: That is what we call the
11 quatrefoil. In that timeframe, yes, they have the
12 LANS, you know, where you have like a --
13 MEMBER SIEBER: Four LANS.
14 MR. HALE: Yes, yes. Right, right.
15 MEMBER SIEBER: And the old ones are just
16 drilled holes?
17 MR. HALE: Right, right, right.
18 MEMBER SIEBER: Quad traps.
19 MR. HALE: Ours were replaced in the `83-
20 84 timeframe at Turkey Point, and we used the same
21 design. They were stainless steel and they had the
22 flow ports, so that you didn't have the drilled
23 support plates.
24 Moving on to slide 29, this just describes
25 the major modifications we have implemented. I

1 indicated the turbine steam path. We are also
2 replacing the control valves and inlet piping to
3 minimize our DP.
4 We are doing major generator work, and we
5 are replacing the rotors in the main generator. And
6 we are also rewinding the electrical generator.
7 MEMBER SIEBER: Didn't you do something
8 with the stater also?
9 MR. HALE: Yes. Yes, we are rewinding the
10 stater.
11 MEMBER SIEBER: Okay.
12 MR. HALE: And we are replacing the rotor.
13 MEMBER SIEBER: And the exciter is still
14 the old exciter?
15 MR. HALE: I get --
16 MEMBER SIEBER: The solid-state exciter
17 where it is tacked on --
18 MR. HANNEMAN: Harv Hanneman, NextEra.
19 Yes, we are not changing the design, but
20 we are changing out the material and we are upgrading
21 the exciter.
22 MEMBER SIEBER: Okay.
23 MR. HANNEMAN: So, it is going to be a
24 refurbishment.
25 MEMBER SIEBER: Okay.

1 MR. HALE: And as we mentioned before,
2 replacing the feedwater and condensate pumps and
3 motors, the feedwater heaters, and levels control, the
4 main transformers, as Larry has mentioned. And we are
5 replacing the secondary moisture separation equipment
6 in the steam generators. This is the peerless veins
7 at the top.
8 DR. WALLIS: And you have still got more
9 carryover than you did before?
10 MR. HALE: Yes, yes. But things are
11 fairly standard. I don't know if you have seen these
12 peerless veins. They are pocket things.
13 DR. WALLIS: You are just putting in the
14 same thing again or something better?
15 MR. HALE: Dual-pocketed veins versus
16 single-pocketed.
17 DR. WALLIS: So, it should be better.
18 MR. HALE: Yes, but the increased flows,
19 you know, offset the benefit of the improved moisture
20 capability.
21 MR. MEYER: The value in that table I
22 think that you are recollecting is an absolute
23 maximum. We are predicting it to be 12 to 50 percent
24 of that.
25 DR. WALLIS: Okay. So, yes, that is the

limit you -- you go stable at that limit anyway.

MR. HALE: Yes. To meet the turbine manufacturer's warranties and --

DR. WALLIS: Are you going to measure this moisture in some way when you upgrade?

MR. HALE: I think our current plan is to do a moisture carryover test.

CHAIRMAN BANERJEE: This is the famous radioactive tracer or --

MR. HALE: Yes, it is a tracer --

MEMBER SIEBER: You can do it calorimetrically, which isn't as accurate as the tracer.

MR. MEYER: Dan T. is the Chief Engineer on the project.

MR. TOMASZEWSKI: I'm sorry. Dan Tomaszewski.

Yes, there is both a radioactive and a chemical tracer. We have used the radioactive in the past, which Steve is referring to. The current plan is to use the chemical tracer.

CHAIRMAN BANERJEE: Oh, you are going to use a chemical tracer?

MR. TOMASZEWSKI: That's correct.

CHAIRMAN BANERJEE: What is the chemical

1 tracer?

2 MR. TOMASZEWSKI: It's potassium

3 something.

4 (Laughter.)

5 MEMBER SIEBER: Yes, salt that you put in

6 there.

7 I noticed that the range, the power factor

8 range, on the generator is relatively narrow. Was it

9 94 percent on the inductive side?

10 MR. TOMASZEWSKI: Point Beach is an older

11 plant, and it was actually backfitted on the

12 interconnection agreement, and the standard power

13 factor is about .9.

14 MEMBER SIEBER: Right.

15 MR. TOMASZEWSKI: The current facility is

16 .95.

17 MEMBER SIEBER: So, you are going to have

18 to back off on top load if you get a more inductive

19 system?

20 MR. TOMASZEWSKI: No, the current plans

21 are in the interconnection for the delta increase we

22 meet the .9, and we are actually improving that.

23 MEMBER SIEBER: Oh, you are? Okay.

24 MR. TOMASZEWSKI: And the generator will

25 meet all the predicted requirements for the system.

1 MEMBER SIEBER: Yes, I guess someplace I
2 read that you were losing power factor capability with
3 the uprate, which I thought in your system might not
4 be a good thing.
5 MR. TOMASZEWSKI: No, we currently should
6 be able to meet all the predicted -- I can't say 30
7 years from now, but currently we should be able to
8 meet all the predicted conditions.
9 MEMBER SIEBER: The alternate is going to
10 use the current carrying capacity of the stater?
11 MR. TOMASZEWSKI: Yes, that's correct.
12 That is --
13 MEMBER SIEBER: As the power factor goes
14 down, the current goes up, but the load on the reactor
15 plant would stay the same.
16 MR. TOMASZEWSKI: That's correct.
17 MEMBER SIEBER: And that is not good from
18 an electrical standpoint.
19 MR. TOMASZEWSKI: Yes, but we have got
20 enough MVA capability in the generator that we can
21 meet the ATC requirements.
22 MEMBER SIEBER: Okay. Thanks.
23 MR. HALE: And that completes my section
24 of the presentation. I think we now move to Jay.
25 CHAIRMAN BANERJEE: Well, there were

1 questions as to whether we should do that or take a
2 break.
3 MR. HALE: Okay.
4 CHAIRMAN BANERJEE: Even though we are a
5 bit early --
6 MEMBER SIEBER: Shall we vote?
7 CHAIRMAN BANERJEE: No, I will make a
8 unilateral decision that we -- would it be okay if we
9 took a break now?
10 DR. MALDONADO: Can you hear me?
11 MR. HALE: Yes.
12 DR. MALDONADO: This is Ivan Maldonado.
13 I just have a very quick question before
14 we go on break. I hope you can hear me okay.
15 MR. HALE: Yes, I can hear you fine.
16 DR. MALDONADO: Excellent.
17 On your slide 28, I noticed that you
18 mentioned that you have an improved operating margin.
19 In general, based on my experience, power uprates
20 generally have a tendency to shrink a little bit your
21 thermal and reactivity margins. And so, an improved
22 margin may allude to the fact that you have recovered
23 margin from somewhere.
24 Can you try to explain a little bit on how
25 you managed to improve margin?

1 MR. HALE: Yes. I think one good example
2 would be one of the critical parameters that operators
3 look at -- now you realize this slide is related to
4 the secondary plant. One critical parameter is feed
5 pump suction pressure.
6 I know that when I did the uprate at
7 Seabrook, you know, the operators said that they were
8 marginal, and if we go to an uprate, they are worried
9 about it and we need to do something about it.
10 But that would be a case where, due to our
11 replacement with the feed pumps and the condensate
12 pumps, we can actually give them better feed pump
13 suction pressure than they currently have. But that
14 would be an example of an approved operating margin.
15 DR. MALDONADO: Oh, okay. I didn't
16 realize it was the secondary.
17 MR. HALE: Yes.
18 DR. MALDONADO: Okay.
19 CHAIRMAN BANERJEE: All right?
20 DR. MALDONADO: Okay. That's good.
21 CHAIRMAN BANERJEE: All right. Any other
22 questions, Ivan?
23 DR. MALDONADO: At this point, no, I am
24 quietly listening. Very interesting.
25 CHAIRMAN BANERJEE: Well, I am sure that

1 you will find the fuel and core part of it
2 interesting.
3 DR. MALDONADO: Yes, I'm looking forward
4 to it.
5 CHAIRMAN BANERJEE: Okay. So, with that,
6 I think what we will do is we are actually ahead of
7 schedule, which seldom happens, but it is very nice to
8 be ahead of schedule.
9 So, we will take a break. Let's take a
10 break until -- now it is 20 to -- until 11 o'clock,
11 okay?
12 So, we will go off the record now. We are
13 on break.
14 (Whereupon, the foregoing matter went off
15 the record at 10:38 a.m. and went back on the record
16 at 11:00 a.m.)
17 CHAIRMAN BANERJEE: We are back on the
18 record.
19 And, Jay, tell us a bit about yourself and
20 then --
21 MR. KABADI: Yes, my name is Jay Kabadi.
22 I am the Nuclear Fuels Manager for NextEra. I support
23 Point Beach fuel designs and cycle-specific reload
24 analysis for every cycle.
25 This morning we presented an overview of

1 the EPU and also talked about some of the changes
2 being done to improve the margins, at the same time
3 keeping sufficient conservatisms in our analysis.
4 What I am going to talk about right now is
5 what we have done and what are the changes in the fuel
6 and also in our fuel management we do every cycle.
7 We will continue to use the same fuel,
8 what we are using right now. Currently, we are using
9 422+ fuel. We implemented that a few cycles ago, and
10 that has been performing very well for us.
11 When we evaluated this for EPU, it looked
12 like that is the right fuel to proceed with that.
13 Only minor changes we are doing fuel. We are changing
14 the actual blanket length from 6-inch to 8-inch.
15 Also, traditionally, we have been using the vessel
16 loading which is IFBA, which is the Westinghouse IFBA,
17 integral fuel burnable absorber.
18 We have been using that concentration in
19 there of 1.5x, which is better, with their loading
20 specifications. We are reducing that to 1.25.
21 Both of the changes are particularly done
22 to gain margins in the rod internal pressure. What we
23 found is with little higher temperatures coming in
24 because of the EPU, more gases will be released
25 through this IFBA and IFBA rods, and that would need

more margin for the gases to expand inside the rods. So, we are expanding the length of the annular actual linkage and also reducing the IFBA loading to gain margins in the rod internal pressure.

As far as the burnup limits go, we are maintaining the same, which is our current 62,000 for the rod burnup. So, there are no changes to the rod burnup limits.

MEMBER SIEBER: Did you say 52,000?

MR. KABADI: Sixty-two.

MEMBER SIEBER: Sixty-two?

MR. KABADI: That's correct.

MEMBER SIEBER: Okay.

MR. KABADI: That is the current approved limit.

MEMBER SIEBER: And your LOCA peak clad temperature, what does that turn out to be?

MR. KABADI: I think I will talk a little bit later about that, too, but we did implement the ASTRUM methodology for large-break LOCA, and that gives significant benefits in the peak clad temperature. Electrical peak clad temperature came out lower than what it is right now.

MEMBER SIEBER: All right.

DR. WALLIS: Did you explain how you get

more power out of the same core? Is there a flattening of the --

MR. KABADI: Yes, I think my next slide I am going to go a little bit on how we are going to achieve --

DR. WALLIS: Oh, I didn't see that.

MR. KABADI: Yes, I think at the same time I will discuss that. I think one of the things we did, which is related to fuel management, is we are reducing the peaking factor, which is the hot channel enthalpy rise factor. In the Westinghouse terminology, it is called F delta H. We are reducing that from a current value of 1.77 to 1.68. That is a typical parameter for all the excellent analyses, but those are related to DNBR. It also helps in other analyses, such as LOCAs, on this one. So, we are reducing that from 1.77 to 1.68.

Another change which has an impact on the operations, we are moving from in the Westinghouse methodologies called RAOC axial offset control for the axial offset, from RAOC -- that is the terminology -- to a constant axial offset control, which is CAOC. And both these methodologies for Westinghouse have been previously approved by the NRC, and Point Beach in the past actually has operated under CAOC.

1 So, we are now moving from RAOC to CAOC.
2 That is a change to the operations also. That
3 provides additional margin both from the fuel
4 performance point of view and at the same time from
5 the DNBR point of view.
6 MEMBER SIEBER: That also requires
7 stricter operator control of rod position, right?
8 MR. KABADI: Particularly for maneuvering,
9 for normal operations and all, you can be still pretty
10 wide, that there is no major concerns there. But
11 whenever there are maneuvers to be done based on that,
12 there will be specific guidance.
13 And the way this process works is that at
14 the lower powers, it will still be the band will be a
15 little wider. But at the full power, about 90, it
16 will be a little narrower in terms of normal
17 operation. And those will be in the procedures and
18 those will be controlled through the tech specs.
19 MEMBER SIEBER: Do you have restrictions
20 on the rate of power increase to avoid power shock and
21 clad tracking?
22 MR. KABADI: Yes. Actually, we are
23 participating very heavily in the EPRI, all the field
24 performance programs, including PCI, and that is a
25 very critical aspect of how fast you go up. We do a

1 specific analysis every cycle. In EPU, we will
2 continue to do that. That will restrict the power
3 ramp rate based on what power level you are and how
4 long you have stayed there during the operation.
5 MEMBER SIEBER: Right. Yes, because there
6 is a relaxation of the clad.
7 MR. KABADI: That's correct.
8 MEMBER SIEBER: And that varies through
9 the core lifetime.
10 MR. KABADI: Yes, right. Yes, we will
11 look at the power to find how the fuel rod previous
12 cycle, which is what it will go to in the next cycle,
13 and based on that, define the ramp rates when we go up
14 in power.
15 MEMBER SIEBER: Yes, sir. And is that
16 more restrictive now than it was before the power
17 uprate?
18 MR. KABADI: It will be the same
19 guidelines, but particularly when we force them in the
20 transition, the change in the power level will be a
21 little more. And we will evaluate under the EPRI
22 guidelines which vendors have implemented, and we are
23 following those to get the detailed calculations of
24 the change in the kilowatt for peak rod and even other
25 rods, and define the ramp rate for every cycle. That

1 is provided for the operations and the reactor every
2 cycle.
3 MEMBER SIEBER: Now this plant does not
4 operate in the load follow mode, right?
5 MR. KABADI: That is correct.
6 MEMBER SIEBER: It is a baseload plant?
7 MR. KABADI: That is correct.
8 MEMBER SIEBER: Okay. Thank you.
9 CHAIRMAN BANERJEE: So, with regard to the
10 RAOC versus CAOC, not chaos -- (laughter) --
11 operation, I thought Ginna was operating in RAOC, is
12 that correct?
13 MR. KABADI: Ginna now I think they
14 shifted the other way around.
15 CHAIRMAN BANERJEE: They shifted to CAOC?
16 MR. KABADI: But I think their RAOC band
17 has been reduced, which is pretty much -- I think that
18 was the option for us --
19 CHAIRMAN BANERJEE: Well, okay.
20 MR. KABADI: -- to look at these. If they
21 stay under RAOC, and then every cycle still receives
22 the band in the same way and keep on rating that every
23 cycle, I will go to a KKR, which is a fixed thing that
24 the operators have liberty and explain very well, and
25 stay with that strategy.

1 CHAIRMAN BANERJEE: And what is Ginna
2 doing?
3 MR. KABADI: I think Ginna right now is
4 under RAOC.
5 CHAIRMAN BANERJEE: CAOC?
6 MR. KABADI: No, RAOC.
7 CHAIRMAN BANERJEE: Oh, RAOC, yes, that's
8 what I thought.
9 MR. KABADI: Right. But in the RAOC,
10 again, the bands could be restricted so much that it
11 could be as good as the CAOC.
12 MEMBER SIEBER: Yes, right.
13 MR. KABADI: So, the difference is only in
14 the RAOC, the band side is defined as a function of a
15 recycle design. And the CAOC, it is a fixed one.
16 What you do is you define your hot full power axial
17 flux difference and stay with that for operations at
18 all power levels. So, you get a wider AO band, but
19 not the AFD band, for those of you who understand.
20 It would be just the difference between
21 the top half of the rod and the bottom half of the
22 rod. AO will just divide that by the power level.
23 So, when you are at lower power, although you are AFD,
24 when you divide by the power, that gets broader. So,
25 your AO band keeps on getting broader at lower powers,

1 but your AFD remains constant.

2 So, the AO band does go bigger, bigger

3 that the RAOC defines. So, operators really have a

4 broad array of band at the lower power levels, but it

5 will be a fixed AFD, which is the flux difference

6 between the top of the core and the bottom of the

7 core --

8 CHAIRMAN BANERJEE: What is the

9 operational, I mean to summarize all this, to tell me

10 in a few sentences, it will give you less operational

11 flexibility to --

12 MR. KABADI: During power maneuvers.

13 CHAIRMAN BANERJEE: Yes.

14 MR. KABADI: During normal operations,

15 generally, these bands are so wide that it doesn't

16 affect much at all. We usually stay within, very

17 close to your center of the band.

18 MEMBER SIEBER: I think you trade operator

19 complexity for added margin.

20 MR. KABADI: Yes, for the operational

21 flexibility, it is mainly doing, whenever they have to

22 go down or something, this does not prevent them, but

23 they have to then -- there are some procedures

24 defining what to do in terms of maneuvering when you

25 go outside the band.

1 CHAIRMAN BANERJEE: I mean the ultimate
2 issue has to do with pellet/clad interactions or what
3 is --
4 MR. KABADI: Yes, essentially, your rod
5 internal pressure affects your pellet/clad
6 interactions. If the pressure goes too high, then you
7 may develop a gap.
8 MEMBER SIEBER: But all these are to avoid
9 power peaking?
10 MR. KABADI: Right. Essentially, your
11 fuel performance, which is dictated by these, is
12 always in the power histories. As you try to evaluate
13 or analyze a wider band, you have to consider power
14 peaking, which goes to power histories, which goes way
15 beyond, which creates some problems in the --
16 CHAIRMAN BANERJEE: The bottom line is you
17 have a flatter core, right?
18 MEMBER SIEBER: Right.
19 CHAIRMAN BANERJEE: I mean that's what you
20 have right now?
21 MR. KABADI: I think the peaking you talk
22 about is separate. This particular one is your
23 operating band in terms of your power between the top
24 and the bottom of the core, not radial balance.
25 CHAIRMAN BANERJEE: Right.

1 MR. KABADI: This one is between top and
2 bottom.
3 CHAIRMAN BANERJEE: But is it also flatter
4 in that direction?
5 MR. KABADI: In the radial, we are
6 reducing that peaking factor from 1.77 to 1.68. That
7 makes it flatter.
8 CHAIRMAN BANERJEE: Yes. And axially, is
9 it also flatter or is it the same?
10 MR. KABADI: During normal operations, it
11 is no constraint. Only during maneuvers, that is
12 where they have to control to a narrower band.
13 MEMBER SIEBER: Right.
14 MR. KABADI: Only when they do some power
15 maneuvers for whatever reason. Some feedwater pump
16 went out and they have to reduce the power, or
17 whatever it is.
18 CHAIRMAN BANERJEE: So, the axial flux
19 shape --
20 MR. KABADI: Yes.
21 CHAIRMAN BANERJEE: -- is essentially
22 similar to pre-fuel --
23 MR. KABADI: For normal operation. But
24 axial flux, what happens is, generally, when you do
25 power maneuvers, for whatever reasons, come down and

1 go up, at that time the flux shifts quite a bit. And
2 there is a restriction on those conditions.
3 MR. MEYER: But for normal operation, the
4 actual flux shape, how does it compare with --
5 MR. KABADI: It will be very similar.
6 CHAIRMAN BANERJEE: Okay.
7 MR. KABADI: For normal operation, axial
8 shape will be very similar to what we have right now.
9 CHAIRMAN BANERJEE: Yes, I got during the
10 maneuvers, obviously, it shifts --
11 MR. KABADI: Right.
12 CHAIRMAN BANERJEE: -- because you are
13 putting stuff in.
14 MR. KABADI: Right.
15 CHAIRMAN BANERJEE: But what I wanted to
16 understand was, does the actual shape change --
17 MR. KABADI: Actually, we have designed
18 this particular cycle, which is outage coming up, and
19 the actual shapes and all are within like a few
20 percentage difference, but nothing that would require
21 changes to the bands of the operation.
22 CHAIRMAN BANERJEE: Okay.
23 MR. KABADI: There are very, very small
24 differences due to the power uprate.
25 CHAIRMAN BANERJEE: Okay.

1 MEMBER SIEBER: You are trading maneuver,
2 but power maneuverability to restrict the rod motion
3 gives you a more constant axial shape?
4 MR. KABADI: That is correct.
5 MEMBER SIEBER: Yes.
6 CHAIRMAN BANERJEE: Okay. Let's move on.
7 MR. KABADI: Yes. And now, the peaking
8 which is reduced, that is controlled by how many fresh
9 assemblies you put in and what is the enrichment you
10 put on them.
11 And now, because of EPU, we have to
12 increase the number of fuel assemblies and placement
13 of the fuel assembles along with the burnable absorber
14 in there, that will determine the peaking factors.
15 So, this will result in using more fuel assemblies.
16 Particularly right now we use in the range of about 36
17 on the average. It may vary from cycle to cycle.
18 That will go in the range of about 44 to 48. And that
19 will be required to maintain the peaking factor below
20 the new limit, which is 1.68 from the current limit of
21 1.77.
22 MEMBER SIEBER: So, what kind of control
23 rods do you use? Are they silver-indium-cadmium or --
24 MR. KABADI: Yes. Yes, we are not
25 changing any, that's correct.

1 MEMBER SIEBER: And you have a burnable
2 poison?
3 MR. KABADI: Under ours, which is
4 Westinghouse IFBA. That is what they call the
5 Integral Fuel Burnable Absorber.
6 MEMBER SIEBER: That is a coating?
7 MR. KABADI: That is a coating outside the
8 rods.
9 MEMBER SIEBER: On the fuel rod, right.
10 MR. KABADI: Right.
11 MEMBER SIEBER: And it is a boron --
12 DR. MALDONADO: Jay?
13 MR. KABADI: Yes.
14 Yes?
15 DR. MALDONADO: Hi. This is Ivan
16 Maldonado again.
17 MR. KABADI: Okay.
18 DR. MALDONADO: I noticed it appears that
19 when you have a higher power being generated, then one
20 manner in which you describe the power is basically
21 being spread through the core; it is by adding fresh
22 fuel assemblies to take on that extra power. And
23 apparently, that helps you reduce the F delta H, the
24 radial peaking factor. Is that correct?
25 MR. KABADI: That is correct.

1 DR. MALDONADO: Okay. Now, with regard to
2 reactivity margins, those are probably also generally
3 tighter because you are obviously going to have more
4 excess reactivity and more fuel in the core. Can you
5 speak a little bit toward what happens to shutdown
6 margin and such on the EPU setup?
7 DR. MALDONADO: Yes. I think lower-down
8 on my slide, I think I have that. I think what we are
9 doing is our current shutdown margin is a sliding
10 shutdown margin, which goes from 1 percent at the
11 beginning of cycle to 3.1 at the end of the cycle. We
12 are changing that to a constant 2 percent, and that
13 accounts for that additional reactivity. And the
14 safety analysis, which is mainly steamline break, has
15 been analyzed at this lower value. And there was
16 sufficient margin on that.
17 DR. MALDONADO: Okay. Now on the core
18 management, did Westinghouse do this analysis for you?
19 MR. KABADI: That is correct.
20 DR. MALDONADO: Did they use any more, I
21 guess, state-of-the-art optimization techniques to get
22 you a better peaking factor?
23 DR. MALDONADO: I think, as I said before,
24 I guess most of the limitations are coming also from
25 the fuel performance point of view. We did not want

1 to challenge our rods to the internal pressure. We
2 wanted to gain as much margin as possible.
3 And as far as optimizing the loading
4 pattern, what we did for this particular EPU analysis
5 is to make sure that we will not have problems from
6 cycle to cycle. The way the designs were done with
7 Westinghouse for this particular EPU project was we
8 designed the representative cycles for transition to
9 equilibrium, and then, also, had a very high react to
10 one cycle, just to bound all these. And that is where
11 all the limits were checked using that.
12 Now cycle specific, we do optimize. We do
13 optimize. We have several optimization codes, and we
14 try to optimize staying within these limits, at the
15 same time trying to gain as much margin as possible.
16 So, we do optimization on a cycle-specific basis.
17 DR. MALDONADO: Okay. Okay. One more
18 question, please.
19 I noticed that the analysis is all done on
20 the basis of the 14-by-14 422 vantage fuel, correct?
21 MR. KABADI: Yes. That is correct.
22 DR. MALDONADO: I mean my experience with
23 other operations of clients is that, if you go for
24 reloads and there is bids for fuel -- is there any
25 thought about the possibility of this fuel type

1 changing in the future and what impact this might have
2 upon the EPU analysis?
3 MR. KABADI: Yes, right now we have no
4 plans of changing from this fuel design. Actually, in
5 our reload process, we also put that as one of the
6 requirements, that even for any last-minute changes or
7 something, we will right now use only 422V+. Now in
8 the future, if some better designs come out, and that
9 is a long-term thing, at that time we would have to
10 evaluate and see what should be done on that. But as
11 far as the fundamental fuel design goes, we have no
12 plans of changing right now.
13 DR. MALDONADO: Okay.
14 DR. BONACA: I have a question. For the
15 full pump loss of flow, how is the minimum DNB
16 changed?
17 MR. KABADI: Yes, I think for full flow,
18 loss of flow, that is what we are talking about? Yes,
19 I think that is one of the events where we use this
20 new methodology RAVE, and that activity will have a
21 significant margin.
22 DR. BONACA: Okay.
23 MR. KABADI: We use that RAVE methodology
24 for two events. One is loss of flow and one is locked
25 rotor. That is what Steve talked about, and that

1 gives us a lot of margin in terms of failed fuel. Our
2 current dose analysis for AST was done with 30
3 percent, and the real help is to get below that.
4 DR. BONACA: Okay.
5 MR. KABADI: And loss of flow will give a
6 significant DNBR margin. So, these are the two events
7 where we use this new RAVE methodology.
8 DR. BONACA: Okay.
9 MEMBER SIEBER: What's the typical reload
10 enrichment reload enrichment of the fuel?
11 MR. KABADI: Well, ou8r limit for
12 enrichment in the tech specs has been 5/8ths percent,
13 even prior to EPU. We are not changing that.
14 MEMBER SIEBER: Based on your spent fuel
15 pool?
16 MR. KABADI: Yes. Right. And we vary
17 from reload between 4 and 4.95 based on the cycle
18 length and all. We mix it between that range.
19 MEMBER SIEBER: And you are on, roughly,
20 an 18-month cycle?
21 MR. KABADI: That is correct, we are on an
22 18-month cycle.
23 MEMBER SIEBER: And what percentage of the
24 core do you change?
25 MR. KABADI: With the EPU, we are

1 expecting, based on using a typical 18-month cycle, we
2 are expecting in the range of 44 to 49, 48-49, based
3 on the central assembly needs to be changed, about 48
4 to 49, which is compared to the current cycles, it is
5 about 36 on the average.
6 MEMBER SIEBER: Okay, and how many fuel
7 assemblies in the core?
8 MR. KABADI: One twenty-one.
9 MEMBER SIEBER: One twenty-one?
10 MR. KABADI: That is correct.
11 MEMBER SIEBER: Okay.
12 CHAIRMAN BANERJEE: So, you are roughly
13 changing a third of the core?
14 MR. KABADI: Right now. With the EPU, we
15 will be changing a little more.
16 MEMBER SIEBER: It would be more than
17 that.
18 MR. KABADI: Right. For the EPU, it will
19 be more than one-third. Currently, we are roughly
20 one-third.
21 MEMBER SIEBER: It was less; now it is
22 more.
23 MR. KABADI: That is correct.
24 MEMBER SIEBER: And your discharge
25 enrichment is going to what, roughly, for the third --

1 MR. KABADI: I think since the enrichment
2 varies 4 to 4.95, all the assemblies eventually will
3 be -- some assemblies, the ones which are 4.95, after
4 three cycles, they will discharge. It reduces
5 slightly. Yes, you are talking about the depletion
6 rate, what's the final?
7 MEMBER SIEBER: Okay. So you have onsite,
8 long-term spent fuel storage?
9 MR. KABADI: Yes. That would be dry cask
10 storage is that, and that is planned with the EPU.
11 MEMBER SIEBER: What's your enrichment
12 limit for that? You wait about five years before you
13 can --
14 MR. KABADI: Right. Decay time is five
15 years. And enrichment, I can check, but it should be
16 five years because we have that process we want for a
17 few years for the dry cask storage.
18 MEMBER SIEBER: Okay.
19 MR. KABADI: And the five-year wait time
20 is for the decay.
21 MEMBER SIEBER: Okay.
22 MR. KABADI: That is correct.
23 MEMBER SIEBER: Thank you.
24 DR. MALDONADO: Jay?
25 MR. KABADI: Yes?

1 DR. MALDONADO: Your boron letdown, how
2 does it change with the EPU relative to the prior
3 operation?
4 MR. KABADI: Our initial boron will go up
5 like with a high reactive core, which we did as a
6 bounding, about 300 ppm. We have spent for the
7 initial boron to go up in the range of about 200, and
8 letdown will just follow the same curve, like we do
9 right now, going from that little higher number to
10 close to 10 ppm at the end of cycle.
11 DR. MALDONADO: Okay. Does the increase
12 in boron affect your MCC and make it less negative?
13 MR. KABADI: At the beginning of cycle, we
14 have the MCC, which is slightly, right, less negative,
15 but when we go to full power it is still very negative
16 to be of any of concern. But it is slightly less
17 negative or more positive, whichever we took it. Yes,
18 it is slightly more positive than what it is right
19 now.
20 DR. MALDONADO: Okay. Thank you.
21 MR. KABADI: Yes. And I think on this
22 slide the only other point I want to make is, as I
23 said before, we developed some representative core
24 designs and took some bounding core designs and set up
25 the limits in the accident analysis. So, we have a

1 margin to cover cycle-by-cycle variations when we do
2 the actual core design.
3 CHAIRMAN BANERJEE: So, is this very
4 similar to what Ginna does?
5 MR. KABADI: In terms of core design? It
6 is a similar core.
7 CHAIRMAN BANERJEE: Yes.
8 MR. KABADI: They actually shift it to
9 422V+ when they went to the EPU. They had a different
10 fuel design before. They went with a fuel design
11 which Point Beach has when they shifted to EPU.
12 CHAIRMAN BANERJEE: So, do the boron
13 requirements go up?
14 MR. KABADI: It should be similar. I
15 didn't check the numbers, but that cycle is based on
16 the cycle lengths, and they are loading in the same
17 range, which they are in the range of 48 and also they
18 are loading every cycle. So, it should be very
19 similar to Ginna.
20 CHAIRMAN BANERJEE: So, when you say it
21 has increased by 300 ppm, what does that mean? What
22 are the implications?
23 MR. KABADI: What that is required to
24 check is, as a part of the cycle-specific design, we
25 do check that all the boration systems have enough

capability to borate the core to get to the required shutdown margin. So, when the critical boron goes up, we may need to borate a little bit with a different either rate or a higher concentration. So, as a part of the cycle-specific checks, we know that if the system has enough capability to borate the system, even when the boron requirement and the critical boron goes slightly up.

CHAIRMAN BANERJEE: And your conclusion was that it has?

MR. KABADI: Yes, this is way below what the system can handle. So, there are no concerns with this. And as I mentioned before, we have already designed a cycle which is waiting for this outage which is coming up, and all this has been checked, also, for this specific design.

CHAIRMAN BANERJEE: Okay. All right.

MR. KABADI: Yes, I think that is pretty much what I wanted to cover in this, unless there are any questions.

CHAIRMAN BANERJEE: Ivan, do you have any questions regarding the fuel and the core?

DR. MALDONADO: Yes, one more question, Jay. Does the burnup, does the cycle length remain basically the same?

1 MR. KABADI: Yes.

2 DR. MALDONADO: Okay. So, the burnup
3 remains also the same because you increase the
4 megawatt-days, but you also increase the metric tons
5 of uranium?

6 MR. KABADI: That is correct.

7 DR. MALDONADO: Okay.

8 MR. KABADI: The only difference will be
9 we will be discharging some, because we are loading
10 more than one-third, some of the fuel will be
11 discharged after two cycles.

12 DR. MALDONADO: Right, right.

13 MR. KABADI: Right.

14 DR. MALDONADO: Yes. My former advisor at
15 NC State University -- some of you know him -- Paul
16 Turinsky, always spoke of the cost of margins and
17 generally decide additional margin by the number of
18 additional bundles that you have to put in the core or
19 discharge.

20 MR. KABADI: Yes, that is correct.

21 DR. MALDONADO: Yes, I have no further
22 questions.

23 CHAIRMAN BANERJEE: Okay. So, let's move
24 on then.

25 MR. KABADI: Okay. Thank you very much.

1 Yes, I think the next topic is on the
2 safety analysis. I will cover that along with Steve
3 Hale.
4 Yes, I think in this presentation what we
5 would like to cover is talk about some of the matters,
6 particularly if they are different than what is used
7 in the current licensing basis. And, then, we will go
8 with some of the other topics outside -- traditional
9 transient analysis is to look at long-term dose
10 consequences, tube rupture. And Steve will talk a
11 little bit about the containment issues.
12 One other thing, when we started this
13 whole process about the safety analysis, is we had, as
14 we talked prior in the discussions, improvements
15 overall to the plant and the conservatisms to be
16 included in the overall process, so we don't run into
17 problems during operation or during design, both ways.
18 So, we tried to use whatever feasible
19 improved methods, and we talked a little bit about
20 some of the improved methods we use. We have to
21 reduce the F delta H, which is the hot channel
22 enthalpy rise factor. That is mainly, again, to
23 improve the fuel --
24 CHAIRMAN BANERJEE: That is what you mean
25 less conservative methods?

1 MR. KABADI: I thought improved methods,
2 that could be looked at, I guess, both ways, less
3 conservative or maybe provide better representation of
4 the system to give more confidence on your reasons.
5 So, it is both ways. I agree that sometimes better
6 methods in terms of final results will be less
7 conservative, but at the same time if the methods have
8 better supporting justification, that provides a
9 little bit better representation of the plan and more
10 confidence on the reasons.
11 CHAIRMAN BANERJEE: Well, anyway, this is
12 semantics.
13 MR. KABADI: No, but that is exactly
14 right. When you say "improved methods", the main goal
15 of that was to see how we can improve our reasons to
16 show margin on paper, which means less conservatism,
17 if you like that way, yes.
18 CHAIRMAN BANERJEE: Yes. ASTRUM
19 clearly --
20 MR. KABADI: Yes.
21 CHAIRMAN BANERJEE: -- is less
22 conservative than --
23 MR. KABADI: That's exactly right.
24 CHAIRMAN BANERJEE: -- existing, I mean
25 the previous methods.

1 MR. KABADI: That is correct. Yes.

2 CHAIRMAN BANERJEE: It is not like you

3 actually do anything other than --

4 MR. KABADI: No, and that is what we get

5 is a lot of margin on the PCT.

6 CHAIRMAN BANERJEE: Yes. Well,

7 realistically, I mean, it is in the eye of the

8 beholder, I guess.

9 (Laughter.)

10 So, let's say less conservative.

11 MR. KABADI: And I have no problem with

12 that.

13 (Laughter.)

14 MEMBER SIEBER: Improved, right.

15 CHAIRMAN BANERJEE: All right. Anyway, go

16 ahead.

17 MR. KABADI: Okay. And other things we

18 implemented here is to gain margin on the fuel

19 performance we talked about and, also, to help in the

20 DNB, which is reducing the F delta H and also the

21 other change we talked about in that axial offset.

22 And the improvement in the AFW gave some benefit in a

23 lot of analysis, particularly the loss-of-feedwater

24 events and other places, too.

25 When we put up all these input parameters,

1 the goal was also to bound the operating parameters so
2 cycle-by-cycle we don't run into problems on
3 violation, both from the physics point of view, which
4 we talked about putting bounding core designs to
5 generate parameters, so that cycle-by-cycle we have
6 margin to meet them.
7 And the last bullet there talks about DNBR
8 limit. This is the typical Westinghouse methodology
9 to define a safety analysis DNBR limit which maintains
10 margin for the real design DNBR limit. So, as long as
11 you meet your safety analysis limit, you have some
12 conservatisms right there that you have some margin.
13 Now the goal is to have margin on top of
14 the safety analysis limit, but the safety analysis
15 limit itself is set to conservatively have a margin
16 beyond the design limit.
17 MEMBER SHACK: So, on your middle bullets
18 there, I mean one of the things that was striking to
19 me was that a number of cases where people have
20 typically used bounding plant operating parameters you
21 used nominal operating parameters, arguing that that
22 was consistent with your current licensing basis,
23 despite the fact that it probably wasn't consistent
24 with some of the methodologies that are typically
25 used.

1 MR. KABADI: And that is, on an event-
2 specific basis, that is correct. And I think like
3 Steve showed one slide this morning which side of the
4 range of parameters, and those are really bounding
5 whenever events require analyzing in a range of
6 conditions.
7 MEMBER SHACK: The implication here is
8 that you are always using bounding plant parameters.
9 MR. KABADI: Yes, that may be qualified by
10 putting methodology used, that is correct. For some
11 methodologies, you initiate the event with the nominal
12 parameters. For example, for DNB, we applied all
13 these uncertainties in a statistical manner and sample
14 it.
15 MEMBER SHACK: Well, it is one thing to
16 use nominal parameters and account for uncertainties.
17 It is another to use nominal parameters and no
18 uncertainties.
19 MR. KABADI: And based on the event-
20 specific analysis, that is true.
21 DR. WALLIS: The containment fan coolant,
22 I just couldn't figure out why it was supposed to be
23 conservative to assume no fouling when fouling was
24 there for good. This was something that was raised by
25 the staff.

1 MR. KABADI: I don't know whether we have
2 that anywhere in the presentation, Steve.
3 DR. WALLIS: It is in the SER.
4 MR. HALE: You are speaking of --
5 DR. WALLIS: It is a water hammer issue
6 with the fan coolers, and there is something about its
7 being conservative to assume no fouling. Usually,
8 fouling is a bad thing, and so you put it in to be
9 conservative. Here you take it out to be
10 conservative.
11 MR. HALE: In what context?
12 MR. KABADI: Can I just maybe relate it to
13 the boiling --
14 DR. WALLIS: Something to do with how fast
15 things happen when you refill or something like that.
16 MR. HANLEY: This is Norm Hanley from
17 Shaw.
18 Zero fouling is usually applied when they
19 do the water hammer. So, you get maximum heat
20 transfer to the fluid in the pipes --
21 DR. WALLIS: Yes, and that makes things
22 worse.
23 MR. HANLEY: Right.
24 DR. WALLIS: Yes. Are you going to
25 discuss that at some time?

1 MR. HANLEY: Yes, we could, but I am not
2 sure if it is on the agenda, Steve.
3 DR. WALLIS: Well, maybe we should have it
4 on the agenda for --
5 MR. HANLEY: This is GL-9606.
6 DR. WALLIS: It in the SER.
7 MR. HANLEY: Right.
8 DR. WALLIS: So, maybe the staff will
9 discuss it. Okay?
10 MR. HANLEY: It is the Generic Letter 9606
11 discussion.
12 MR. HALE: Typically, you would assume
13 zero fouling when you are looking at water hammer.
14 DR. WALLIS: Make things happen as fast as
15 possible.
16 MR. HALE: Right.
17 DR. WALLIS: Well, maybe the staff will
18 bring it up. We can ask the staff about this because
19 they discuss it in the SER to some length. Okay.
20 CHAIRMAN BANERJEE: Bill, are you
21 satisfied with the discussion on the bounding --
22 MEMBER SHACK: We are going to be coming
23 back to this.
24 CHAIRMAN BANERJEE: Yes.
25 MEMBER SHACK: And the staff will be

1 coming to it.

2 CHAIRMAN BANERJEE: Yes.

3 MEMBER SHACK: It just struck me there as

4 they sort of said it, but it is not really quite --

5 DR. BONACA: That is why I have been

6 asking for some better definition of what is the

7 licensing basis if it not the current one.

8 Is Point Beach part of the Systematic

9 Evaluation Program?

10 MR. HALE: Harv I think can answer that.

11 MR. HANNEMAN: Harv Hanneman from NextEra,

12 Point Beach.

13 No, Ginna was the last plant to be under

14 the SEP program. We were actually next in line, but

15 we never had to initiate that program. So, we never

16 went through that formal program.

17 DR. BONACA: But, still, you have

18 exceptions to the current licensing basis?

19 MR. HALE: I think it is important to

20 clarify.

21 MR. HANNEMAN: I think we followed the

22 RS-001 guidance in doing all of our evaluations and

23 analysis in general under the current licensing basis.

24 DR. BONACA: Right.

25 MR. HANNEMAN: In several cases we were

1 challenged by the staff. In some cases I think we
2 went beyond and did some additional things to answer
3 questions from the staff.
4 MR. HALE: Yes, we don't have any -- Steve
5 Hale, NextEra -- we don't have any cases where we did
6 not follow our licensing basis. We had cases where
7 there were conditions and evaluations we performed
8 beyond our current licensing basis. And that was only
9 a handful.
10 But ones that you are speaking of are
11 related to the steam generator overfill. Point Beach
12 did not have a steam generator overfill analysis.
13 Okay? So, we went through back and forth quite a bit
14 with the staff in terms of assumptions, evaluations,
15 and things of that sort. So, that is a type of thing
16 that we are talking about.
17 DR. WALLIS: You are going to talk about
18 that later?
19 MR. HALE: Yes, yes, but it is only a
20 handful. I don't want to give the impression that --
21 Jay is talking about all the Chapter 14 for Point
22 Beach safety analyses. And typically, this is what we
23 followed.
24 We had a couple of select events where we
25 got into a lot of exchange with the staff, and

1 specifically in the area of the steam generator
2 overflow analysis. And I will get into that a little
3 later.
4 DR. BONACA: Yes, I was asking the
5 question before about the loss of flow, because it is
6 a fundamental design transient for DNB. And now the
7 answer is, actually, that you have higher power and
8 the same flow, but your DNB has gone up, rather than
9 down, because you are using different methodology.
10 And so, it is hard for me to make a
11 judgment of how much the power increase is affecting
12 DNB. I believe the numbers you are presenting there,
13 but I don't get an answer to myself, you know, what is
14 the relative effect because the methodology has
15 changed.
16 CHAIRMAN BANERJEE: Well, it was the same
17 with the LOCA analysis. We don't really know, I mean,
18 what it is compared to before because they have simply
19 changed the methodology. But that is part of the
20 issue with the first -- it is fine. I mean it is
21 legal, but it is more a question of what is the real
22 change.
23 DR. BONACA: But you want to know --
24 CHAIRMAN BANERJEE: Yes.
25 DR. BONACA: -- what it is, so that you

1 can make a proper comparison/judgment. I completely
2 agree that it is legal, but --
3 CHAIRMAN BANERJEE: We took a long time
4 approving best testaments plus uncertainties. I spent
5 15 years of my life on it. So, it is all right.
6 MR. KABADI: Yes, I think we have not done
7 like an RAVE with the current thing to see how much is
8 the delta that way.
9 CHAIRMAN BANERJEE: It is giving you
10 margin, so be happy. You can operate the plant.
11 (Laughter.)
12 MEMBER SHACK: Don't worry.
13 MR. KABADI: And some of the margins were,
14 I think, based on the RAVE methodology as it is
15 approved, what is expected. Now much exactly, what
16 number, once running the analysis that was found
17 out --
18 CHAIRMAN BANERJEE: I guess the question
19 he is asking, which is in all our minds really, is, in
20 fact, of course, while you are using approved
21 methodologies and we have put a lot of money into
22 developing these methodologies, and clearly to buy you
23 margin, what we don't know is, if you had used the old
24 methodology, what would have been the change. You
25 see? So, clearly, clad temperature would have been

1 something. I don't know what it would -- 2200, 2300,
2 whatever, and now it is like 1950 or something like
3 that.
4 And, similarly, with DNB, by changing the
5 methodology you have got, you are able to do this.
6 MR. KABADI: Yes, I think without I guess
7 putting any quantification --
8 CHAIRMAN BANERJEE: Yes.
9 MR. KABADI: -- I think while looking into
10 this, I think the option was, if it did not go with
11 the new methodology, would I have been reducing F
12 delta H further down?
13 CHAIRMAN BANERJEE: Yes.
14 MR. KABADI: And before evaluating how
15 much down, we would evaluate it and say how much you
16 could stay with if you used the new methodology. But
17 that is correct, if we have stayed with the current
18 loss-of-flow methodologies, we would have probably
19 reduced it further down, so that we can meet the DNBR
20 limits.
21 CHAIRMAN BANERJEE: Sure.
22 MR. KABADI: But what we did is, at that
23 time, we say RAVE is a new methodology. Was it
24 approved? Let's see with that how much we can save
25 it, leaving sufficient margin that we meet what we

1 call the safety analysis limits and above. And that
2 is what we ended up with, that 1.68.
3 CHAIRMAN BANERJEE: It is fair enough. It
4 funds all the thermal hydraulics and such. How can we
5 complain?
6 (Laughter.)
7 So, this is a tangible result of all this.
8 MR. KABADI: No, I understand.
9 CHAIRMAN BANERJEE: Yes. Go ahead.
10 MR. KABADI: And the next slide.
11 DR. WALLIS: Maybe it is a better way to
12 regulate.
13 CHAIRMAN BANERJEE: Sure. Why not? It is
14 more realistic.
15 Please, next slide.
16 This is a somewhat academic discussion.
17 MR. KABADI: Yes. No, I agree.
18 Yes, I think this slide just presents what
19 are the changes we did with respect to the pre-EPU,
20 which is our current licensing basis. One thing we
21 did is all the transient analysis we moved from the
22 LOFTRAN to the Westinghouse new methodology, which is
23 based on the RETRAN.
24 CHAIRMAN BANERJEE: What was the reason
25 for that? Because, you know, did that give you

1 improved modeling?

2 MR. KABADI: Yes, I think that modeling

3 was -- RETRAN is that newer in the Westinghouse

4 methodology. LOFTRAN was the old code. And we are

5 better now. In terms of comparison, I am not saying

6 whether you need more margin or less, but that is a

7 better methodology in terms of --

8 CHAIRMAN BANERJEE: But when it comes to

9 these large transient tests and things, you are still

10 using LOFTRAN, right?

11 MR. KABADI: Yes, for design transients,

12 which I think maybe we have on a slide for tomorrow

13 maybe. Yes, for that we use LOFTRAN.

14 CHAIRMAN BANERJEE: But why this sort of

15 dichotomy of codes? Sometimes you use LOFTRAN and

16 sometimes you use RETRAN.

17 MR. KABADI: Well, one of the things, I

18 think, at least what we know is LOFTRAN was validated

19 against the Ginna results and all, and we knew that

20 the transient response which was predicated by LOFTRAN

21 at that time with the Ginna results showed good

22 comparison.

23 CHAIRMAN BANERJEE: Right.

24 MR. KABADI: So, that is one reason. Why

25 we did not shift, I don't know whether Steve or anyone

1 can answer that.

2 CHAIRMAN BANERJEE: Yes, I was curious

3 about that. So, perhaps somebody can answer that

4 question. Why did you go to RETRAN when you used

5 LOFTRAN with other things?

6 MR. DOMINICIS: Is this working?

7 This is Dave Dominicis from Westinghouse.

8 For the control system transients and the

9 design transients, we always use LOFTRAN. The

10 LOFTRAN, it is sufficient to do the job we are trying

11 to do, which is to try to model the control systems

12 and the design of the plant.

13 RETRAN is a more detailed analysis used

14 for safety analysis. It has also been used in the

15 past for -- or I'm sorry -- LOFTRAN has also been used

16 in the past for safety analysis. Westinghouse is

17 getting away from LOFTRAN and, in general, moving

18 toward RETRAN.

19 CHAIRMAN BANERJEE: So, what are the

20 features in RETRAN which make it better than LOFTRAN?

21 MR. DOMINICIS: Let me defer to one of my

22 friends over here.

23 MEMBER SIEBER: It's 3D.

24 CHAIRMAN BANERJEE: Is it the 3D?

25 MR. FONTES: I'm Jorge Fontes with the

1 Westinghouse non-LOCA safety analysis group.

2 RETRAN provides a lot of flexibility that

3 LOFTRAN does not have. LOFTRAN is hard-wired in many

4 ways, and there are many things that you can't model

5 in LOFTRAN that you can with RETRAN.

6 The primary reason in switching to RETRAN

7 for Point Beach is that we were planning on switching,

8 also, to the RAVE methodology, and for that you need

9 RETRAN.

10 CHAIRMAN BANERJEE: Now RETRAN, and this

11 gets, of course, for these transients you start to get

12 boiling and things like that, right? So, you get two-

13 phase flow.

14 MR. FONTES: Yes.

15 CHAIRMAN BANERJEE: What sort of two-phase

16 flow model is in RETRAN? Is it too fluid or drift

17 flux?

18 MR. FONTES: I don't think the transients

19 will allow it to boil.

20 CHAIRMAN BANERJEE: You are not allowed

21 to? So, RETRAN is not being used with any boiling?

22 MR. FONTES: Yes.

23 CHAIRMAN BANERJEE: So, at the moment, all

24 right, if there was no boiling, it is a single-phase

25 flow.

1 MR. FONTES: Yes.

2 CHAIRMAN BANERJEE: Then it is okay. But,
3 you know, this Committee has had some concerns with
4 RETRAN being used in boiling.

5 MR. FONTES: Yes.

6 CHAIRMAN BANERJEE: So, if you assure us
7 it is not, then but you are sure of that?

8 MR. FONTES: Yes, we are.

9 CHAIRMAN BANERJEE: Okay. All right. And
10 we are on record with our concerns about it, and you
11 see boiling. All right.

12 Let's go.

13 MR. KABADI: The other change we did is go
14 to the RAVE methodology we talked about before for
15 loss-of-flow and locked rotor.

16 One other change that was done is, when
17 using RETRAN, RETRAN has been approved to take credit
18 for thick metal mass. We took credit for that on some
19 events when using RETRAN, particularly for loss of
20 feedwater.

21 And the last one is one where we do not
22 have this event in the current licensing basis, but we
23 introduced that for the EPU, and that is a hot full-
24 power steamline break.

25 And outside this tube rupture, whatever we

1 did outside design basis, Steve is going to cover that
2 later.
3 Okay. This just gives you an overview of
4 some of the key events, acceptance criteria, what we
5 found when the full project was done, that all the
6 non-LOCA events met there except for loss of flow.
7 DNB came out about the safety analysis limit, and the
8 locked rotor fuel failure is below the AST requirement
9 of 30 percent.
10 DR. WALLIS: Some of them are very close.
11 MR. KABADI: That is correct. Well,
12 compared to safety analysis limit, they were very
13 close, but --
14 DR. WALLIS: That is okay because?
15 MR. KABADI: The safety analysis limit has
16 about 7 to 10 percent margin embedded in that. The
17 real design limit for DNBR is in the range of about
18 1.24 to 1.26.
19 DR. BONACA: But your peak pressure is
20 2750, and you are awfully close.
21 MR. KABADI: That is correct. For peak
22 pressure, actually, we are a little better than what
23 we are right now. I think our current peak pressure
24 is a little higher than that.
25 DR. WALLIS: They are very close.

1 MR. KABADI: Yes.

2 DR. WALLIS: How do you justify getting so
3 close? Is it because you have some conservatisms in
4 there?

5 MR. KABADI: Well, all the modeling which
6 is done for this particular event covers the plant
7 operation normally, so that there are no other
8 concerns, although we would like to have more margin,
9 also, on that. But based on the EPU done and the
10 results of this analysis, we actually gained a little
11 margin compared to the current one.

12 DR. WALLIS: But can you really predict
13 within a fraction of 1 percent these values? How can
14 you justify being so close to the limit? It would
15 seem that a very slight inaccuracy in something would
16 push you over, right?

17 MR. KABADI: Well, one other thing I think
18 we ought to note here is all the safety valves
19 operation and all has been all biased to be on the
20 worse side for all the safety valves, both on the
21 primary side and on the secondary side.

22 DR. WALLIS: The information and
23 everything are biased for the worse?

24 MR. KABADI: For peak pressures they have
25 been bias.

1 DR. WALLIS: Okay. I think that is a main
2 justification.
3 MR. HALE: And there are conservatisms
4 built into the safety limits themselves in terms of --
5 MR. KABADI: And the trip setpoints are
6 also biased a little bit more than what it should be
7 on those ones.
8 CHAIRMAN BANERJEE: So, let's go through
9 these one by one because you are covering a lot of
10 stuff there.
11 So, the first, decrease loss of flow, Dr.
12 Bonaca had some questions. Are you questions
13 answered, Mario, or not?
14 DR. BONACA: Yes.
15 CHAIRMAN BANERJEE: Do you need more
16 clarifications?
17 DR. BONACA: It shows, you know, a better
18 result for the EPU planned, but that is because of
19 calculation of the improvements.
20 CHAIRMAN BANERJEE: Right.
21 DR. BONACA: So, I would expect that if
22 they had used the same methodology, they may not have
23 made 1.3.
24 CHAIRMAN BANERJEE: Right, but this is --
25 DR. BONACA: This is fine.

1 CHAIRMAN BANERJEE: Yes, this is an
2 approved methodology.
3 Now, with regard to overheating, are there
4 any questions, reduced secondary site cooling, that we
5 need clarifications or understanding of?
6 With regard to overcooling, we are very,
7 very close to the criterion, right, on LHR there?
8 MR. KABADI: I think one of the things,
9 this particular event was analyzed with very
10 conservative trip setpoints, but, overall, other
11 conservatisms we mentioned. The trip setpoint has a
12 big impact on this. This is a hot full-power
13 steamline break, and when we have the trips, that is
14 when the event is over to go how far in power. So,
15 this was biased to a very high trip setpoint compared
16 to what real would happen.
17 CHAIRMAN BANERJEE: So, you are saying
18 that it doesn't matter that you are calculating this
19 to three significant figures or four, whatever that
20 number is, that there are enough conservatisms that we
21 should accept that without worrying about it?
22 MR. KABADI: Yes. Well, what we do, like
23 this is a reactivity check which also we do site-
24 specific to verify that the cycle-specific design is
25 less. And we always find less limiting numbers than

1 what are used in the analysis. But you are right,
2 analysis, the numbers, the way they were generated
3 using all the reactivity parameters, do come very
4 close to the limit.
5 CHAIRMAN BANERJEE: Yes.
6 MR. KABADI: And that has been typical for
7 this event in general. And we verified that we do
8 have margins to those reactivity parameters running to
9 state points for every cycle to make sure that we
10 don't even come to like a decimal place there.
11 CHAIRMAN BANERJEE: Yes. So, perhaps the
12 staff will comment on this because some of these
13 numbers, of course, are very, very close to the
14 criteria, right?
15 MR. KABADI: Right. The heat fraction
16 number here and the LHR numbers.
17 CHAIRMAN BANERJEE: Yes, those margins in
18 the criteria, that is --
19 DR. WALLIS: But is it big enough to
20 overcome this other uncertainty?
21 CHAIRMAN BANERJEE: Well, it is like the
22 2200 clad temperature model.
23 MEMBER SIEBER: Yes, there's margin there.
24 CHAIRMAN BANERJEE: Yes, there is margin
25 there.

1 DR. BONACA: What I am asking myself is,
2 you know, as you said, the data or the results may be
3 affected by changing methodology in some cases, like,
4 for example, the loss of flow; we discussed that.
5 But, then, you said in some case the assumption is
6 made that there is an uncertainty; initial conditions
7 are nominal. And here there is no explanation for
8 these cases, whether or not you have nominal values or
9 conservative values.
10 So, there are different assumptions that
11 may be played, and the numbers by themselves don't
12 tell me enough.
13 MR. HALE: I can speak to these events.
14 We did not use nominal numbers in these events that
15 were evaluated.
16 MR. KABADI: Right, the limiting event
17 which are overcooling, as I mentioned, all the
18 reactivity parameters are pretty much bounding, which
19 we verify every cycle, and, then, a trip setpoint has
20 been used very conservatively.
21 DR. BONACA: Okay. So, for these
22 analyses, they are just showing here you used a
23 conservative approach?
24 MR. KABADI: That is correct.
25 DR. BONACA: Okay.

1 CHAIRMAN BANERJEE: And with that, it was
2 the same?
3 MR. KABADI: Yes. That was, again, our
4 real MCCs come nowhere to what is used in the
5 analysis, which used 95/95 number. And the cycle-
6 specific, when we designed codes, those are real less
7 negative, more negative than what is used in the ATWS.
8 CHAIRMAN BANERJEE: Okay. I mean the
9 thing is the criteria and the results in several cases
10 are very, very close.
11 DR. WALLIS: The next page they are equal.
12 (Laughter.)
13 MR. KABADI: Yes, this slide talks about
14 the reactivity additionally, which is rod withdrawal
15 and rod ejection. In the rod withdrawal, the safety
16 analysis limit and what was calculated were the same.
17 So, the margin available is what is between the
18 safety analysis limit and the real design limit, which
19 is in the range of about 1.26 or 1.24, based on what
20 it is. So, there is some margin, but we could not,
21 based on the way the analysis is done, we could not
22 give them any additional. There are conservatisms in
23 the sense of the reactivity insertion rate used. Our
24 actual numbers are below that. So, we don't reach
25 those --

1 DR. WALLIS: When the numbers are the
2 same, it looks as if you had to tweak something. It
3 looks very unusual. Did you have to point at
4 something or back off on something or modify something
5 to get this number to be 1.337?
6 MR. KABADI: No. I think what actually
7 happened is we wanted to set a safety analysis limit
8 as high as we can, so we maintain some margin. In
9 this case, we could not. So, this is actually the
10 safety analysis limit was set based on what we could
11 get. So, it is like a reverse thing here.
12 DR. WALLIS: So, you set the criterion to
13 meet the results?
14 MR. KABADI: Well, not the design -- the
15 design set at 1.26. That was the design limit that we
16 must meet. And we tried to set up the safety analysis
17 limits to cover --
18 DR. WALLIS: That is one of those things
19 that is a bit artificial.
20 MR. KABADI: That is correct.
21 CHAIRMAN BANERJEE: Yes, it is 1.38,
22 right, the safety analysis?
23 MR. KABADI: Right. On many of those, we
24 like to set 1.38, so we didn't go to margin, but our
25 real limit we did not want to get close to is 1.26.

1 We do not want to get there.

2 DR. WALLIS: Yes, I remember that sort of

3 thing. That's right.

4 CHAIRMAN BANERJEE: I think we understand

5 the rationale behind this.

6 DR. WALLIS: It is a bit mysterious when

7 it becomes the safety analysis limit. It sort of

8 varies depending on the plant, and so on.

9 MR. KABADI: Right. And I think since we

10 are working with different vendors, I guess it is

11 just, as I mentioned in the beginning, Westinghouse

12 methodologies all used a set of safety analysis

13 limits, so you maintain a certain amount of margin

14 compared to your real design limit for the DNBR. So,

15 as long as you meet that, we know you have some margin

16 there. The other option was to always present a

17 design limit and say I have margin on top of it.

18 CHAIRMAN BANERJEE: So, here the

19 reactivity addition, the safety analysis limits, the

20 DNBR is set as 1.337, right? And, then, if you go to

21 loss of flow, it is 1.38. And, then, for certain

22 cases, it is 1.30, 1.45.

23 Can you just explain the rationale for

24 these?

25 MR. KABADI: The 1.337, that is the one

1 which is, as I mentioned just now, that that was
2 brought down, but still about the DNBR limit. The
3 other ones are based on correlations. Like the 1.30
4 is for the W3 correlation which is used; 1.38 is for
5 that WRB-1 correlation.
6 So, based on different events, you use
7 different correlations for that. And, also, it
8 depends on whether you or how you combine the
9 uncertainties on that. But most of the differences
10 are based on correlation.
11 For example, that 1.30, that is for the W3
12 correlation, and the 1.38, that is for the BRB-1
13 correlation.
14 CHAIRMAN BANERJEE: It would be helpful to
15 -- you know, I did read this part of the application
16 and the SER. It would be helpful to put this all in
17 context because in certain cases, of course, you are
18 using W3, and so on. To remember precisely where one
19 is used, this is rather arcane knowledge, you know.
20 So, it would be useful to sort of give us an overview
21 at some point of where what applies and why all this
22 keeps changing. I think I understand the rationale,
23 but it would be good summarizing it.
24 And, then, we can just move on, I think.
25 We have no more questions.

1 MR. KABADI: Okay. ASTRUM large-break
2 LOCA analysis was previously approved, and that has
3 been referenced in the EPU. And the peak clad
4 temperature for the limiting one came out 1975 for the
5 large-break LOCA. That is a little better than we
6 have right now for the current licensing basis.
7 CHAIRMAN BANERJEE: This is, of course,
8 Mario's point again, you know.
9 MR. KABADI: Right, and this is mainly a
10 big benefit going from the current best estimate model
11 to the ASTRUM. And that provided, you mentioned
12 previously, a significant benefit in the --
13 DR. WALLIS: You are playing a
14 probabilistic game. You could have easily have gotten
15 a different number if you ran the whole thing again.
16 (Laughter.)
17 CHAIRMAN BANERJEE: Well, if you go to not
18 95/95, but if you go to 99/99 --
19 DR. WALLIS: No, 95/95 doesn't give you
20 the same number every time you do it.
21 CHAIRMAN BANERJEE: Of course, because it
22 is probabilistic.
23 DR. WALLIS: But, you know, the Appendix K
24 does.
25 (Laughter.)

1 MR. KABADI: Right, because Appendix K is,
2 yes, more prescriptive. And this is just the numbers
3 that were generated with ASTRUM.
4 DR. WALLIS: So, 1810 may differ from 1975
5 just by probability rather than anything physical.
6 CHAIRMAN BANERJEE: Which runs your
7 sample.
8 DR. WALLIS: Your sample. It is an
9 interesting approach.
10 CHAIRMAN BANERJEE: Well, I think you
11 approved it, Graham, when you were on the Committee,
12 didn't you?
13 DR. WALLIS: It is an interesting
14 approach.
15 CHAIRMAN BANERJEE: Yes. Right.
16 MR. KABADI: Yes, part of the difference
17 is some parties, maybe the difference, it can stem
18 under the design, but the main reason is because of
19 the methodology.
20 CHAIRMAN BANERJEE: Yes, so let me
21 separate this part. I mean, suddenly, we understand
22 well the thing in the table. But with regard to the
23 long-term cooling, I think we need to come back to
24 that here.
25 MR. KABADI: I think that for long-term

1 cooling some specific analyses were done for Point
2 Beach. It was defined operator actions, and Steve is
3 going to talk about that a little bit later.
4 CHAIRMAN BANERJEE: Yes, yes. We were
5 interested. So, I think we understand what is going
6 on here with this.
7 DR. WALLIS: What is revealing is to also
8 quote the best estimate value on 95/95. If you take
9 the average of all those computations, you get
10 something like 15-1600 I think.
11 CHAIRMAN BANERJEE: Yes, that would
12 actually be useful to do.
13 DR. WALLIS: That would be useful.
14 CHAIRMAN BANERJEE: Yes. Because,
15 otherwise, you don't know what is sleight of hand and
16 what isn't.
17 (Laughter.)
18 So, it would be useful to have the best
19 estimate values so we know what uncertainties they are
20 putting on it.
21 DR. WALLIS: Do we have that somewhere?
22 Is it somewhere?
23 CHAIRMAN BANERJEE: I didn't see it. Did
24 you?
25 DR. WALLIS: But you could find them out

1 and tell us later in the day or something?

2 MR. KABADI: The best estimate for the EPU

3 or for the --

4 DR. WALLIS: Yes, for the EPU, what is the

5 best estimate? These are the maximums of 95/95.

6 MR. KABADI: Okay. I am not going to

7 do --

8 DR. WALLIS: But if you have got 59 or 100

9 runs, you have an average value, too.

10 CHAIRMAN BANERJEE: You have maybe 300

11 degrees less.

12 DR. WALLIS: Yes.

13 CHAIRMAN BANERJEE: So, it would give us a

14 nice, warm feeling.

15 (Laughter.)

16 DR. WALLIS: Well, warmer means closer to

17 2200, does it?

18 CHAIRMAN BANERJEE: We know that the

19 uncertainties have to be 600 to get to 2200.

20 MR. MEYER: We have got that action item.

21 MR. KABADI: Yes.

22 CHAIRMAN BANERJEE: Okay.

23 MR. KABADI: And the next slide.

24 In the small-break LOCA, we did three

25 changes which pretty much offset all the EPU impact.

1 We reduced F delta H using the analysis. The tube
2 plugging level in the analysis was reduced from 25 to
3 10, which we used for all the EPU analysis, and the
4 actual offset before going from RAOC to CAOC, that
5 also reduced the actual offset.
6 All these three combined, the next slide
7 shows that the PCT came out very close, not too much
8 different than the current --
9 CHAIRMAN BANERJEE: Well, it was 1811
10 versus 1683, right?
11 MR. KABADI: No.
12 CHAIRMAN BANERJEE: Oh, sorry. Okay.
13 Yes.
14 MR. KABADI: They came out very close to
15 the current on this one.
16 CHAIRMAN BANERJEE: Okay. This was
17 performed with NOTRUMP, correct?
18 MR. KABADI: Right.
19 CHAIRMAN BANERJEE: With this EPU, is
20 there any period during which you get into reflux
21 condensation for the small-break LOCA?
22 MR. KABADI: Can Westinghouse, anyone --
23 CHAIRMAN BANERJEE: Who did this analysis?
24 MR. KABADI: Westinghouse did that
25 analysis.

1 CHAIRMAN BANERJEE: Yes. Was there any
2 period where you are in refluxing and you need to have
3 the loop seal clearing?
4 MR. SHEAFFER: Hi. This is Mark Sheaffer
5 from Westinghouse.
6 Can you repeat the question? I couldn't
7 hear you back there.
8 CHAIRMAN BANERJEE: Did you go into reflux
9 condensation any period during this small-break LOCA?
10 MR. SHEAFFER: I am not sure. I would
11 have to defer that to someone else, but I can find out
12 for you.
13 CHAIRMAN BANERJEE: Yes. And, also, this
14 is two plants. So, I would like to know what time the
15 loop seals cleared.
16 MR. SHEAFFER: Off the top of my head, I
17 am not sure, but the loop seal clearing time for the
18 limiting 3-inch break is probably around under 100
19 seconds, in that timeframe. I am not sure, but I will
20 double-check for you.
21 CHAIRMAN BANERJEE: Okay. And you have
22 the two loops. What happens to the broken loop? Does
23 the seal clear?
24 MR. SHEAFFER: Yes, for the broken loop
25 what happens is we restrict the loop seal clearing on

1 -- or for the intact loop we restrict loop seal
2 clearing on that.
3 CHAIRMAN BANERJEE: Yes.
4 MR. SHEAFFER: And we allow the broken
5 loop to seal once we get enough vapor buildup to blow
6 the loop seals clear.
7 CHAIRMAN BANERJEE: Okay. The reason for
8 the refluxing question is that it is the ratio of flow
9 in the hot leg, through the hot leg elbow. In the EPU
10 you have a higher vapor flow to the steam generator.
11 So, the issue that arises there is whether you get
12 flooding in the hot leg or not, and if you have a
13 significant time for reflux there.
14 MR. SHEAFFER: Yes, I will have to find
15 that out.
16 CHAIRMAN BANERJEE: Yes. So, just check
17 it. I would like to get an idea of whether refluxing
18 is significant or not here as a cooling mod.
19 MR. SHEAFFER: Okay.
20 CHAIRMAN BANERJEE: Because it may not be.
21 This is not an EPR or something.
22 MR. SHEAFFER: Right.
23 CHAIRMAN BANERJEE: Right. Okay. Thanks.
24 MR. KABADI: This is all I had on these
25 topics. If there are no more questions, then Steve

1 will continue the safety analysis.

2 CHAIRMAN BANERJEE: Thanks.

3 Now let me just look at the time because I

4 don't want to kill your lunch break. We are running

5 slightly beyond our time. So, let's see -- oh, no,

6 no, we are not. Lunch was from 11:45 to 12:45.

7 MEMBER SHACK: Right. So, we are working

8 in the safety analyses.

9 CHAIRMAN BANERJEE: Oh, okay. Sorry.

10 MEMBER SHACK: We can go for lunch.

11 DR. WALLIS: We can go for lunch.

12 (Laughter.)

13 CHAIRMAN BANERJEE: I was just wondering

14 whether this might be a natural spot to break, go for

15 lunch, and then not let anybody get too hungry. And,

16 then, we have plenty of time to come back and do this.

17 I think there is a lot of interest in this.

18 So, my suggestion, if we all agree, is

19 that we go for lunch now. If it is okay, you can

20 defer this until after lunch. And, then, we take an

21 hour's lunch break and come back at 10 past 1:00.

22 MEMBER SIEBER: Ten past 1:00.

23 CHAIRMAN BANERJEE: Ten past 1:00.

24 DR. WALLIS: You're very generous.

25 MEMBER SIEBER: We will make you Chairman

1 forever.

2 (Laughter.)

3 CHAIRMAN BANERJEE: All right. We will

4 take a break.

5 Off the record.

6 (Whereupon, the foregoing matter went off

7 the record for lunch at 12:07 p.m. and went back on

8 the record at 1:10 p.m.)

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

1:10 p.m.

CHAIRMAN BANERJEE: Okay. So, we are going to go back on the record and start.

We're still in open session, right? Yes.

MR. HALE: Hi. My name is Steve Hale again from NextEra.

I will be covering long-term LOCA cooling, talk about boric precipitation, talk some about the dose analyses that were performed under our AST, and also discuss our steam generator margin to overfill analysis.

Additionally, we would like to address the open questions that we had. Hopefully, we will have answers by the end of today, if we could go through those, if that would be okay.

We did want to confirm that we had answered your question on the tables. There was a question regarding the upper and lower flow-induced vibration monitoring, and I think we answered your question there, right?

MEMBER SHACK: Yes.

MR. HALE: Okay, good.

1 MEMBER SHACK: They had accelerometers at
2 Ginna. And so, these are based on essentially the
3 measurements at Ginna.
4 MR. HALE: Okay. With regard to the
5 emergency core cooling --
6 CHAIRMAN BANERJEE: The accelerometers are
7 on the pipes themselves?
8 MEMBER SHACK: Right. They are mounted.
9 CHAIRMAN BANERJEE: Okay. Thank you.
10 MR. HALE: Okay. With regard to the
11 emergency core cooling system at Point Beach, it is
12 similar to Ginna. On the injection phase, we have
13 upper plenum injection with the RHR pumps, and the
14 high head safety injection pumps inject to the cold
15 legs.
16 As the RWST level goes down, we make a
17 transition to the recirc phase and RHR is transferred.
18 It is suction. We transfer suction from the RWST
19 fueling water storage tank to the sump, and that is
20 done without interruption of flow. So, we always have
21 flow to the core during that transition.
22 During the injection phase, we have
23 flushing from both locations, both upper --
24 DR. WALLIS: What does flushing mean here?
25 MR. HALE: We have essentially a flow in

1 both directions through the head and through --

2 DR. WALLIS: You can't have flow in both

3 directions through the core.

4 MR. HALE: Hum?

5 DR. WALLIS: You can't have flow in both

6 directions through the core.

7 MR. HALE: Yes, from the upper plenum --

8 DR. WALLIS: But, then, where does it go

9 if it is coming in both ends?

10 MR. HALE: It will eventually go out the

11 break.

12 DR. WALLIS: Okay. So, how does it get

13 there? I don't understand.

14 MR. KABADI: This is Jay Kabadi.

15 I think the injection to the primary

16 system is from both sides, the cold leg and hot leg

17 side. The flow will go based on where the break is.

18 DR. WALLIS: But it might go nowhere. It

19 might stall. I mean if you get it from both ends,

20 they might just not go anywhere. Mightn't that be an

21 additional point in the core?

22 MR. KABADI: And that is why the flushing

23 flow, I think the requirement is the flow is greater

24 than the boiloff. So, if the break is on the hot leg

25 side, the cold leg flow has to go through the core to

1 get out of the break. And if that flow is greater
2 than the boiloff, it will flush the boron from the
3 core. And by the same token, the other way around --
4 DR. WALLIS: That is going in one
5 direction through the core.
6 MR. KABADI: Right.
7 DR. WALLIS: When you put in this upper
8 head and upper plenum injection as well, what happens
9 then?
10 MR. KABADI: Right. One of the injections
11 where the break is, that flow will just go out. But
12 the injection from the other side will flush the core.
13 DR. WALLIS: So, it depends on which break
14 you have?
15 MR. KABADI: That is correct. That is why
16 injection is not on both sides.
17 MR. HALE: And the size of the break.
18 DR. WALLIS: Because just the simultaneous
19 injection by itself doesn't do anything. You might
20 make things worse. It is just that if it is a break
21 on one side, it has to go out that way. And so, it
22 selects one of those flows to flush the --
23 MR. KABADI: Right, and without knowing
24 where the break is, if you put the injection on both
25 sides, it can flush the core depending on where the

1 break is.

2 DR. WALLIS: And flushing the core for you

3 means there is a flow right through?

4 MR. KABADI: That is correct.

5 MR. HALE: Exactly.

6 DR. WALLIS: And there are no particulates

7 blocking the flow anywhere here? There is no debris

8 blocking the flow?

9 MR. KABADI: No. In this thing, the core

10 is intact.

11 DR. WALLIS: There is no downstream

12 effects from the strainers?

13 MR. KABADI: And that is already a topic

14 of --

15 MR. HALE: Yes, we are speaking the

16 injection phase right now.

17 DR. WALLIS: I thought you were talking

18 about long-term -- you talked about coming from the

19 sump. Isn't that long-term cooling?

20 MR. HALE: Right now, we are talking about

21 the alignment of the ECCS system.

22 DR. WALLIS: You were talking about the

23 sump as well just now.

24 MR. HALE: Well, we transfer to

25 recirculation. I will get into --

1 DR. WALLIS: You will get into that later?
2 MR. HALE: Yes.
3 DR. WALLIS: Okay. So, this is before the
4 recirculation phase?
5 MR. HALE: Well, in transitioning to the
6 recirculation phase, we wanted to make it clear that
7 there is no interruption of ECCS flow during that
8 transition.
9 DR. WALLIS: But this flushing from both
10 and flushing for all break locations is before the
11 drum cooling?
12 MR. HALE: Yes, for the injection phase is
13 what we are talking about here.
14 DR. WALLIS: Okay. Okay.
15 MR. HALE: Move on to the next slide.
16 Looking specifically at the boric acid
17 precipitation, the scenario for large break, you know,
18 you have the rapid depressurization. We have mixing
19 or Westinghouse models have mixing in the reactor
20 vessel for that break location.
21 Some of the conservatisms in the analysis:
22 we don't credit any mixing of the upper injection
23 flow. We don't take any credit for some of the sump
24 additives, which would have a tendency to increase the
25 solubility limits in the boric acid. And we don't

1 credit any containment pressure above atmospheric for
2 the boric acid analysis.
3 CHAIRMAN BANERJEE: How large are these
4 flows? You say credit for mixing with one-half the
5 lower plenum volume? How do you arrive at that one-
6 half?
7 MR. HALE: Brett Kellerman, who did the
8 analysis for Westinghouse, is here. He could respond
9 to that question.
10 CHAIRMAN BANERJEE: Right.
11 MR. KELLERMAN: Good afternoon.
12 Brett Kellerman from Westinghouse.
13 The one-half lower plenum represents what
14 we have seen in test data from several facilities,
15 Finnish and Japanese.
16 CHAIRMAN BANERJEE: That is one-seventh
17 scale, right, the test facilities?
18 MR. KELLERMAN: The Finnish tests were
19 fairly small-scale, maybe one or two fuel assemblies.
20 The Japanese tests were a slab, roughly 1 over 81, a
21 single row of assemblies, full radial slab, but full
22 height.
23 And based on the concentration gradients
24 observed in those tests, we derive an effective volume
25 of one-half of the lower plenum.

1 CHAIRMAN BANERJEE: Yes, I am just
2 wondering about, you know, what is the velocity coming
3 into the lower plenum? This is heavier than water,
4 right?
5 MR. KELLERMAN: Right, as the
6 concentration builds up, and with this being a UPI
7 plant design, you don't have or at least during this
8 phase you don't have the injection from the cold leg
9 through the downcomer up in. So, you don't have that
10 momentum to overcome. But the convector velocity is
11 down out of the core. I don't know offhand, but it
12 could be --
13 CHAIRMAN BANERJEE: It is not very much.
14 MR. KELLERMAN: -- tens of centimeters per
15 second.
16 CHAIRMAN BANERJEE: Yes. Okay, but I
17 would like to see a rationale for this one-half. With
18 the test that you are talking about they were smaller-
19 scale, but you think they were representative in some
20 way of --
21 DR. WALLIS: There is a history of this,
22 isn't there? The ACRS was told the basis for this in
23 the past.
24 MR. KELLERMAN: Right, it was originally
25 brought up during the Waterford uprate about six years

1 ago.

2 CHAIRMAN BANERJEE: Okay. So, you

3 accepted this one-half?

4 DR. WALLIS: Well, there were a lot of

5 questions at that time, I think. But I think the

6 staff accepted it.

7 CHAIRMAN BANERJEE: I see.

8 DR. WALLIS: I am not quite sure what our

9 position was.

10 CHAIRMAN BANERJEE: So, let me ask it in a

11 different way, then. If it was different from one-

12 half, what would be the effect?

13 MR. KELLERMAN: The result is fairly

14 sensitive to that volume because your remaining water

15 is highly voided in the core. So, single-phase lower

16 plenum volumes.

17 CHAIRMAN BANERJEE: So, if it was less

18 than one-half, the situation would get --

19 MR. KELLERMAN: The calculated time to

20 reach the precipitation limit would shorten, yes.

21 CHAIRMAN BANERJEE: It would be shorter?

22 MR. KELLERMAN: Yes.

23 CHAIRMAN BANERJEE: And so, maybe the

24 staff will address this, but one of the issues was

25 this time to reach precipitation being fairly short,

1 right?

2 MR. KELLERMAN: Yes. The moment you

3 calculate that precipitation time, it is not like the

4 core lower plenum turns into a block. It forms

5 crystals generally in the bottom of the vessel and

6 builds up. At least that is what we have seen in

7 tests.

8 CHAIRMAN BANERJEE: Well, I think what we

9 can do is we can revisit this when the staff comes on.

10 I am sure they have looked at it in some detail.

11 MEMBER SIEBER: It is an open item.

12 CHAIRMAN BANERJEE: Yes. No, but it is

13 now closed, right, because they have taken care of it

14 in this?

15 MEMBER SIEBER: I don't know.

16 CHAIRMAN BANERJEE: Yes.

17 MR. HALE: We can describe what actions we

18 have taken as a result of the review with the staff.

19 CHAIRMAN BANERJEE: Yes. So, it would be

20 worth at least putting down the rationale for this

21 one-half lower plenum, if that is possible to do.

22 You say, Graham, that we actually looked

23 at this at some point in the past?

24 DR. WALLIS: What's the name of the test?

25 MR. KELLERMAN: The BACCHUS test.

1 DR. WALLIS: BACCHUS?

2 MR. KELLERMAN: Right.

3 MEMBER SHACK: We accepted it for
4 Waterford because there was a significant margin to
5 the boron solubility limit. However, there may be
6 generic issues that are related to precipitation of
7 boric acid. The BACCHUS test results blah, blah,
8 blah. There is no quantification of the mechanisms or
9 an assessment of how applicable the results are to the
10 general case.

11 DR. WALLIS: So, we weren't very happy.

12 MEMBER SHACK: We weren't very happy.

13 DR. WALLIS: I remember that, yes. Yes.

14 MEMBER SHACK: We bought off on it because
15 there was a big enough margin.

16 DR. WALLIS: What year was that?

17 MEMBER SHACK: Hum?

18 DR. WALLIS: What year?

19 MEMBER SHACK: 2005.

20 CHAIRMAN BANERJEE: Yes, I need to get a
21 copy of the letter as well.

22 MS. ABDULLAHI: For Waterford?

23 CHAIRMAN BANERJEE: Yes. Because it was
24 before my time.

25 MEMBER SHACK: It was before your time.

1 CHAIRMAN BANERJEE: Right.

2 DR. WALLIS: Before your time.

3 CHAIRMAN BANERJEE: Okay.

4 MR. HALE: I think one of the things we
5 wanted to indicate, there are conservatisms in our
6 analysis outside of the one-half assumptions. We
7 don't credit any mixing from the UPI flow. There are
8 sump additives and there is also containment
9 overpressure. It would all tend to increase the
10 solubility limits of boric acid in water. There is no
11 credit for that in the evaluation. So, I just wanted
12 to make sure to make you aware of that.

13 Our calculated time to reach the
14 solubility limit where you have initiate cold leg
15 injection, we calculated to be about four hours and 50
16 minutes from the onset of the event.

17 Based on our dialog with the staff, we
18 have agreed and are implementing changes or will
19 implement changes to our EOPs that will require us to
20 initiate that within three hours and 30 minutes, which
21 gives us over an hour margin in terms of reaching the
22 solubility limit.

23 So, those were the changes we made as a
24 result of the interaction with the staff. The staff I
25 know is going to talk about what they did and what

1 their reviews were.

2 In terms of the ability to restore cold
3 leg injection within that timeframe, actually, our
4 operators can do that within 10 minutes, because we
5 have to essentially terminate the -- our system is
6 such that we have a piggyback arrangement where the
7 containment spray pumps are piggybacked with the RHR
8 pumps. So, we can't run the containment spray pump at
9 the same time we run the high head pump. So, as soon
10 as we turn off the containment spray pump, we turn on
11 the high head pump in that piggyback configuration,
12 and we can actually accomplish that within 10 minutes.
13 So, that has been factored into our operating
14 procedures, and that requirement will appear there.

15 MEMBER SIEBER: Yes, but operators have to
16 do this and they have to recognize that they are in
17 this situation with a limited time to take this
18 action.

19 MR. HALE: Exactly. Exactly. So, this
20 will be clearly delineated, and that was additional --
21 before, all we had was an ultimate limit as to when
22 you needed to do it, but now we have a requirement
23 that says, once we terminate containment spray, we
24 will initiate cold leg injection within 10 minutes.

25 CHAIRMAN BANERJEE: How sensitive is this

1 four hours 50 minutes to the power level? Like this
2 is 1800 megawatts thermal or something, right?
3 MEMBER SIEBER: Right.
4 CHAIRMAN BANERJEE: What was it before
5 EPU?
6 MR. HALE: I think one of the --
7 MR. KELLERMAN: Pre-EPU, the operator
8 action time was 14 hours.
9 MR. HALE: Yes, but that, I believe,
10 Brett, we didn't have a rigorous analysis like we do
11 now, is that correct?
12 MR. KELLERMAN: It was provided to Point
13 Beach from the staff in 1974.
14 MR. HALE: I mean it is somewhat dated,
15 the analysis that we had. I don't know if we are
16 comparing apples to apples, I guess is what I am
17 saying, because that analysis was some time ago.
18 CHAIRMAN BANERJEE: Because now you are
19 using COBRA/TRAC or something?
20 MR. HALE: Yes, yes, we are have refined
21 models. And in this case, the boron precipitation was
22 kind of those issues in the industry that evolved, and
23 the analysis we had was somewhat dated.
24 CHAIRMAN BANERJEE: Do you recall -- or
25 maybe we should ask the staff -- but how the staff

1 analysis of 14 hours, or whatever the time was, I mean
2 in rough terms, how that was done?
3 MEMBER SHACK: Now you're asking for
4 institutional memory.
5 (Laughter.)
6 CHAIRMAN BANERJEE: There are people on
7 the staff here that I see. Len should know this,
8 shouldn't you? How was it done? How did you guys
9 do, not you, but your predecessors, how did you do
10 that time to reach -- Len, you have to go to the
11 microphone. Identify yourself.
12 The question is --
13 MR. WARD: Len Ward, NRC staff.
14 CHAIRMAN BANERJEE: -- how was this 14
15 hours, or whatever the number was pre-EPU, arrived at
16 back in the seventies?
17 MR. WARD: Yes, what little documentation
18 I have managed to find on that, I found one where --
19 and this is what precipitated the issues that I
20 brought up three years ago that the Owners' Groups are
21 now dealing with on boric acid methodology testing.
22 But I wasn't getting the same
23 precipitation time with my calcs. It was off by a
24 significant amount. And that was during the Waterford
25 review.

1 But what Westinghouse was assuming was
2 that at 30 percent core void fraction, based on a 24-
3 hour or 15-hour precip time, now with the CPUs they
4 are shifting up to five and six hours; the void
5 fraction is more like 70-80 percent. So, that is a
6 significant change. That is huge. They weren't
7 accounting for that properly.
8 And the multiplier on decay heat was 1.1,
9 not 1.2, and taking credit for the entire lower
10 plenum, there is test data out there that shows that
11 the lower plenum participates, but in some cases not
12 the entire portion. So, some tests show, I know a CD
13 test that we did many years back showed the entire
14 lower plenum was involved.
15 But, anyway, basically, it is the void
16 fraction assumption just got carried over from years
17 and years without somebody changing it, and they kept
18 using it. And the decay heat multiplier was 1.1, not
19 1.2.
20 I mean, if you look at decay heat of
21 multiplier 1.0 versus 1.2 with a precip time of around
22 four hours with a 1.2, you will buy another couple of
23 hours. It is very significant. I mean it is 20
24 percent power, and it is a power volume ratio. The
25 smaller the volume, the higher the power; the

1 concentration goes up very fast.

2 And it is also a strong function of the

3 source. I mean 15, 20, 25 years ago RWC

4 concentrations were 1700 and 1800 ppm. Now they are

5 32000 ppm.

6 And, then, you find boric acid storage

7 tanks that have high concentrate boric acid, 12-14

8 weight percent. If that thing actuates, you can

9 precipitate in less than two hours.

10 So, I know and my CD experience was that

11 the early 2700-megawatt class plants all had boric

12 acid storage tanks, and if those discharged, we would

13 precipitate really early. So, what we did as part of

14 the OP guidance said, within 15 minutes post-LOCA make

15 sure that, one of the immediate actions, the operators

16 turn those things off. And that was part of the

17 immediate actions.

18 And I will talk about it here, though, but

19 Point Beach is doing the same thing. But, anyway, it

20 was a lot of those functions carried through from 15

21 years ago.

22 CHAIRMAN BANERJEE: Yes. I guess we are

23 trying to understand the sensitivity of the four hours

24 or five hours to the various assumptions. Part of it

25 is they have improved their predictiveness along the

1 way.

2 MR. WARD: Well, what the vendors are

3 doing now is they are in a process; they are going to

4 do some testing. They are going to put together a

5 formal model and a topical and submit it.

6 I know when I was at Combustion in the

7 late seventies, we put together a topical report on

8 boron and submitted it to the staff, and it was

9 approved based on test data, what we had back in the

10 late seventies.

11 But I want all the vendors to have their

12 own model, so that we can make sure that we completely

13 understand what they are doing. And it is a formal

14 review. It is going to be based on test data. So, we

15 are in that process right now. So, it is ongoing.

16 I would like to see it progress faster,

17 but at least they are making progress. They are

18 getting ready to do some tests, and we want to take a

19 look at those.

20 We will have input to that. We meet a

21 couple of times a year to talk about what is going on

22 there. So, this is something that will get done.

23 CHAIRMAN BANERJEE: Okay. All right.

24 Thank you, Len.

25 All right, you can continue.

1 MR. HALE: Next slide, Jay.

2 This just summarizes the boron

3 precipitation relative to the small-break scenario.

4 Certainly there's longer amounts of time, and

5 depending on the small break size, we may be still

6 long high pressure injection, but, generally, it is

7 not as severe as a large-break scenario in terms of

8 boron precipitation.

9 Next slide.

10 To talk a little bit about the Alternate

11 Source Term, this is a separate license amendment.

12 But since our dose consequences in the EPU reference

13 the AST, we thought it would be worthwhile just to hit

14 a few of the key points.

15 We looked at full implementation of AST.

16 We looked at Chapter 14 events. Being an older plant,

17 that is where our accident analysis lies. In other

18 plants it is Chapter 15.

19 We did follow the methodology in Reg Guide

20 1.183.

21 We assumed unfiltered in-leakage for our

22 limiting events. It is around 200 cfm. Tests we

23 performed in the past show it actually around 70-75,

24 in that range.

25 We do consider LOCA dose associated with

1 recirculation in the auxiliary building and the
2 refueling water storage tank. And we looked at doses
3 at low population zone and CR doses and confirmed that
4 they are within the acceptance criteria of 10 CFR
5 50.67. These analyses were submitted separately.
6 The next slide there, Jay.
7 As part of our AST analysis, we performed
8 what we call kind of a bounding analysis of the steam
9 generator tube rupture event. This is consistent with
10 what has been done by other utilities.
11 Margin to overfill was not originally part
12 of the licensing basis for Point Beach. So, if you
13 went to Point Beach, you looked at the SAR, you looked
14 at the analysis, we did not have a margin-to-overfill
15 analysis.
16 What was typically done for ASTs is they
17 would make some very conservative assumptions with
18 regard to releases, everything to maximize releases,
19 and then you would do sensitivity evaluations and
20 analyses to confirm that, from a dose standpoint, you
21 were within those conservative assumptions based on
22 realistic times and things of this sort.
23 And there was no analysis done for margin
24 to overfill. We chose, as part of our license
25 amendment, to perform one of these, I will call it,

1 sensitivity-type analyses for margin to overfill,
2 which had been accepted in the past. So, we thought
3 there was some precedence to that from some of the
4 other utilities that had addressed that.
5 There was a WCAP that was written. I show
6 up there, 10698. That was written for NTOLs that were
7 in the process of being licensed at the time of a tube
8 rupture then at Ginna. And as a result of that, that
9 methodology was adopted by all the NTOLs as well as
10 Ginna because they had the event.
11 We did not perform our original
12 sensitivity analysis consistent with that methodology.
13 That methodology called for use of conservative
14 bounding values versus nominal values and that sort of
15 thing.
16 But, as a result of our interface with the
17 staff, we did go back and reevaluate our margin-to-
18 overfill analysis consistent with that approved
19 methodology with one exception, and that exception was
20 the assumption of a single failure. We did not assume
21 a single failure for tube rupture event for Point
22 Beach, but what we did do is, through a process of
23 interfaces with the staff and audits, demonstrate that
24 with the assumption of a single failure, we had enough
25 defense-in-depth to accommodate that failure and

1 demonstrate that we would not overfill the steam
2 generator.
3 So, essentially, what you will hear from
4 the staff is a similar type of summary. The critical
5 component here is the atmospheric dump valves for
6 margin to overfill. That is on the intact steam
7 generator. You know, the focus was all on radioactive
8 releases, but from a margin-to-overfill analysis
9 standpoint, you want to make sure you can cool down to
10 where you can equalize pressure. And you need your
11 ADD in order to do that. The ADDs at Point Beach are
12 instrument-air-operated.
13 But what we did is we went through
14 different demonstrations of the availability of the
15 instrument air, and even to the point of doing manual
16 actions on the ADD to demonstrate that we could
17 prevent overfill, even with the assumption of failure
18 of the ADD.
19 MEMBER SHACK: Now you do need to isolate
20 the ruptured steam generator within six minutes, which
21 not being a plant person I don't know; that seems
22 awfully quick.
23 MR. HALE: No, that is something that they
24 are tested in and are able to accomplish, okay? All
25 the times we assumed in our overfill analysis were

1 validated by operations testing and through their
2 normal qualification processes.
3 DR. WALLIS: Isn't this the point where
4 you needed to credit items from the other unit?
5 MR. HALE: Well, the instrument air
6 system, like I said, if you focus on the critical
7 failure assumptions, it is failure of the ADD on the
8 intact steam generator, because with a two-loop plant
9 if you have got one generator that has faulted, you
10 need the other generator to cool down the equalized
11 pressure.
12 And the ADDs are air-operated. Our
13 instrument air system is a shared system. We have
14 four compressors. We have got two compressors that
15 are instrument air and two service air compressors.
16 So, part of the defense-in-depth review
17 that was performed by the staff was looking at dual-
18 unit loops where you have an accident, a rupture on
19 one unit, and the other unit is in a loss of offsite
20 power. What kind of sequence do the operators go
21 through?
22 We demonstrated and showed that one of
23 their primary focuses is to get instrument air
24 restored. So, when you look at those scenarios and
25 the evaluation they did, they even came to the site

1 and observed some of our simulator runs, which I
2 thought was beneficial. We demonstrated our ability,
3 even with the assumptions being made, that we could
4 prevent overfill.
5 DR. WALLIS: So, the other unit can be
6 operational and you can still --
7 MR. HALE: Yes, the instrument air
8 compressors are all able to be aligned to the diesels.
9 We have four buses, and each one of the compressors,
10 the two instrument air and the two service air, can be
11 aligned to the individual buses.
12 So, the likelihood of having a steam
13 generator tube rupture plus a dual-unit loop, plus
14 loss of all of our air compressors, was considered
15 kind of out there. And the evaluation was done to
16 demonstrate that we could operate the valves.
17 The likelihood of loss of instrument air
18 is pretty low, and that even in the case where we
19 didn't, we could demonstrate, and we actually
20 demonstrated this to the staff, our ability to access
21 the valve and manually operate it. Diagnose, you
22 know, that the valve was not working and getting the
23 operating dispensed to the ADB and to simulate
24 operation of ADB.
25 MEMBER SIEBER: Do you have a PRA for these

1 units?

2 MR. HALE: Yes.

3 MEMBER SIEBER: Yes. Have all of these

4 actions been modeled in the PRA?

5 MR. HALE: Yes. This one is not real

6 significant when you look at all the probabilities.

7 We are in the 10 to the 9th, 10 to the minus 9th, 10

8 to the minus 10th range in that.

9 When you take a tube rupture is a full

10 double-ended tube rupture, a dual-unit loop, plus

11 single failure, it really gets --

12 MEMBER SIEBER: Right. Well, the tube

13 rupture probability is, I would say that that is not

14 too remote.

15 MR. HALE: Well, I think --

16 MEMBER SIEBER: A dual-unit loop is

17 probably remote.

18 MR. HALE: the full double-ended rupture

19 that occurred at Ginna is, based on the inspections

20 that are performed nowadays, the better materials, and

21 the controls, I think that certainly, if you look at

22 the history, and we reviewed this in detail, as you

23 might imagine, when we got into this discussion, that

24 there are ruptures that have occurred, but nothing of

25 a type like Ginna had, say, in the early seventies.

1 A lot of that we have to credit with the
2 focus on good inspection programs, both on the tube
3 side as well as the secondary side, you know, control
4 of lose material. I believe in the Ginna case they
5 had a big piece of steel that actually caused the dual
6 rupture.
7 The likelihood of having a leak, I would
8 say, is there, but of a double-ended rupture like we
9 are talking, I mean we are talking a 750 gpm type that
10 we are evaluating here, I guess.
11 DR. WALLIS: I found the story quite long
12 really.
13 (Laughter.)
14 And there seemed to be a lot of operator
15 steps. And maybe the thing to do is to wait for the
16 staff to explain to us why it was okay rather than try
17 to go through the whole story now.
18 MEMBER SIEBER: That will be interesting.
19 DR. WALLIS: Yes.
20 CHAIRMAN BANERJEE: We can revisit when we
21 get to the staff. I am sure we will have questions
22 for you.
23 MR. HALE: Okay. And we do have Mike
24 Millen, our Senior Operations Lead for the EPU, who
25 will be speaking tomorrow. And he will be covering

1 operator training and operating procedures and also
2 talk about power ascension. I think he can also
3 address it because he was part of the overall
4 assessment and evaluation that was done here.
5 MEMBER SHACK: Again, this is one of the
6 places where you are different than Ginna. They have
7 a lot more margin than you do.
8 MR. HALE: They do.
9 MEMBER SHACK: Yes.
10 MR. HALE: They do. Their steam
11 generators are bigger. There's no doubt about it, you
12 know.
13 But I think that the steps we took, you
14 know, the additional steps we took, even though it
15 wasn't in our licensing basis, were appropriate. And
16 I think it is the right thing to do to address the
17 overfill.
18 Okay, next slide, Jay.
19 Talking about containment peak pressure,
20 we did go to GOTHIC for our containment pressure
21 analysis. The result of the EPU, our peak pressure is
22 55.7 psig, which is less than our design pressure at
23 60.
24 And, then, the other criteria were less
25 than 9 psig 24 hours out in the event, which is less

1 than the criteria of 50 percent of the calculated peak
2 pressure.
3 I am sorry, this is LOCA, not main
4 steamline break. But in LOCA, we saw a slight
5 increase in the peak pressure, about 1.9 over the
6 current licensing basis for LOCA analysis.
7 DR. WALLIS: Well, the temperature is also
8 higher, isn't it?
9 MEMBER SIEBER: Yes.
10 MR. HALE: Yes.
11 DR. WALLIS: The containment temperature.
12 And this is what affected the coolers and the water
13 hammer issue that I brought up before. And as I
14 understand it, you had to assume some fouling in order
15 to make this scenario satisfactory?
16 MR. HALE: We have an action that we will
17 discuss, not this evaluation. The evaluation that we
18 are talking there is the Generic Letter 96-06
19 evaluation, looking at elevated temperatures on closed
20 piping systems.
21 DR. WALLIS: And this is the water hammer
22 and the coolers issue?
23 MR. HALE: Right, right, right.
24 DR. WALLIS: Are we going to discuss that
25 here or not?

1 MR. HALE: We have an action to address
2 that. Hopefully, we will be able to do that by the
3 end of the day.
4 DR. WALLIS: Okay.
5 MR. HALE: All right?
6 DR. WALLIS: Okay.
7 CHAIRMAN BANERJEE: So, the peak pressure
8 was 1.9 psi higher than your --
9 MR. HALE: Right.
10 DR. WALLIS: How much higher was it? How
11 much higher?
12 CHAIRMAN BANERJEE: It is 55.7. Is that
13 the peak pressure?
14 MR. HALE: Yes, 55.7 is our current peak
15 pressure. So, we increased a couple of pounds to
16 about -- well, our current, I mean the peak pressure
17 is 55.7. We were 1.9 less than that for our current
18 CLB.
19 CHAIRMAN BANERJEE: And what is your peak
20 temperature?
21 MR. HALE: Peak temperature is around 291,
22 I believe, was it, Norm? We just reevaluated that.
23 MR. HANLEY: Norm Hanley from Shaw.
24 The recent analysis just done was 282 --
25 MR. HALE: Two eighty-two.

1 MR. HANLEY: -- for the LOCA case that was
2 done.
3 MR. HALE: Yes.
4 DR. WALLIS: Two eighty-two?
5 MR. HALE: Yes.
6 CHAIRMAN BANERJEE: And what is the peak
7 temperature in the sump water that you get in the
8 LOCA. I am now thinking more on the long-term side.
9 MR. HALE: I will have to defer to that.
10 I believe we assumed 212.
11 CHAIRMAN BANERJEE: It is below boiling?
12 DR. WALLIS: At this pressure, yes.
13 CHAIRMAN BANERJEE: Yes, of course, but --
14 MR. HALE: Well, we don't assume that
15 pressure because that is the benefit.
16 CHAIRMAN BANERJEE: No, no, I realize
17 that. I am just asking for the temperature. So, the
18 question is, how much does the sump water temperature
19 go up due to the EPU for the long-term recirculation
20 case?
21 DR. WALLIS: The water is not due to NPSH?
22 CHAIRMAN BANERJEE: Yes.
23 DR. WALLIS: Yes.
24 CHAIRMAN BANERJEE: We are going there,
25 slowly.

1 DR. WALLIS: Okay. We are going to get
2 there?
3 CHAIRMAN BANERJEE: Yes, we are getting
4 there.
5 MR. HALE: We will have to get back with
6 that answer.
7 CHAIRMAN BANERJEE: Okay.
8 MR. HALE: I know the GSI-191 evaluations
9 on NPSH accommodate the EPU, but what the delta and
10 water temperature --
11 CHAIRMAN BANERJEE: Yes. So, leaving
12 aside any issues related to GSI-191, I am saying, if
13 you assume no head loss through the screens, just take
14 it zero head loss of the screens, how much is the NPSH
15 affected by the EPU? That is the question.
16 MR. HALE: I think we can address what it
17 is with the EPU.
18 CHAIRMAN BANERJEE: Yes, with the EPU.
19 You must have a number without the EPU, right?
20 MR. HALE: Well, yes, we do. I just don't
21 know if I have it handy here.
22 CHAIRMAN BANERJEE: Okay. Well, do you
23 have the number with EPU?
24 MR. HALE: Yes.
25 CHAIRMAN BANERJEE: If you don't have the

other number, that would be --

MR. HALE: Do you know where the backup slides are, Jay?

We might as well talk about GSI-191, I'm thinking.

DR. WALLIS: If your water temperature is 212 and you are assuming no contained delta pressure --

MR. HALE: Yes.

DR. WALLIS: -- then your pumps must be pretty low down. Can you tell us that?

MR. HALE: I will tell you what the elevation heads are.

CHAIRMAN BANERJEE: If you want to address the issue now, you can, but I don't want to necessarily interrupt the flow of your presentation. So, it is up to you how you want to do that.

MR. HALE: Well, we anticipated at about this stage is where we would start talking --

CHAIRMAN BANERJEE: The slides would have to go into the record, of course, yes.

MR. HALE: Yes.

MEMBER SHACK: It is slide 15 in the backup package, if you have it on your computer.

CHAIRMAN BANERJEE: I do.

1 MEMBER SHACK: Well, I suppose it is even
2 in here. I never look at the paper version.
3 CHAIRMAN BANERJEE: That is because you
4 have a Mac.
5 It's not in here, I don't think.
6 MR. HALE: The one with the delta P is the
7 first slide.
8 CHAIRMAN BANERJEE: So, this packet
9 doesn't have the backup slides?
10 MR. HALE: No. We do have the backups
11 loaded. We didn't know which ones that would be
12 needed.
13 CHAIRMAN BANERJEE: Fine.
14 MR. HALE: We anticipated this one would
15 be.
16 (Laughter.)
17 MEMBER SHACK: It should have been No. 1.
18 (Laughter.)
19 MR. HALE: Right.
20 We thought we would first run through the
21 NPSH without credit for containment overpressure. The
22 available head at minimum sump level is about 27.5
23 feet.
24 DR. WALLIS: So, how do you get that? The
25 pumps are --

1 MR. HALE: Located below that sump level.
2 DR. WALLIS: So, you have them buried?
3 MR. HALE: Yes. Typically, the RHR pumps
4 are probably the lowest pumps in your plant. Okay?
5 CHAIRMAN BANERJEE: So, roughly one
6 atmosphere?
7 MR. HALE: Yes, roughly.
8 CHAIRMAN BANERJEE: I mean gauge.
9 MR. HALE: Yes. The frictional head
10 losses due to the piping, you can see there is 7.3
11 feet. NPSH required is about 16. So, if you add
12 those up versus available head without taking credit
13 for containment overpressure, we are looking at
14 available of about 4.2 feet for delta P across the
15 screens. That is the current condition, assuming no
16 containment overpressure, assuming some minimal
17 containment overpressure, 12.7 psig.
18 CHAIRMAN BANERJEE: How do you come to
19 that 12.7?
20 MR. HALE: That was kind of a value that
21 is out there, lower out there, in terms of it takes
22 credit for containment integrity certainly.
23 CHAIRMAN BANERJEE: Yes, and also, I mean
24 using GOTHIC or something, you get sort of an upper
25 bound.

1 MR. HALE: Yes.

2 CHAIRMAN BANERJEE: So, this would have to

3 be a lower bound.

4 MR. HALE: Lower bound.

5 CHAIRMAN BANERJEE: So, when you say that

6 12.7, is it based on the upper bound or on the lower

7 bound?

8 MR. HALE: Twelve point seven would be

9 based on the lower bound.

10 CHAIRMAN BANERJEE: The lower bound?

11 MR. HALE: Right. You have to do a LOCA

12 analyses, a minimum pressure event, when you evaluate

13 peak clad temperature. And so, you have to use

14 minimum pressure values when you do that.

15 CHAIRMAN BANERJEE: That is for the break

16 flow?

17 MR. HALE: Yes.

18 CHAIRMAN BANERJEE: Okay.

19 MR. HALE: But if you use the minimum

20 pressure value, then we would have margins to

21 accommodate other issues that are currently being

22 discussed with the staff, like flashing and de-

23 aeration, and that sort of thing across the streams.

24 CHAIRMAN BANERJEE: Yes. And, also, of

25 course, during a large-break LOCA, when you are doing

1 that calculation, it is a relatively short period of
2 time --
3 MR. HALE: Right.
4 CHAIRMAN BANERJEE: -- this could be
5 happening further down.
6 MR. HALE: Right.
7 CHAIRMAN BANERJEE: Okay, but at the
8 moment you have 4.2 feet available?
9 MR. HALE: Right. And that is assuming
10 EPU conditions.
11 CHAIRMAN BANERJEE: Yes.
12 DR. WALLIS: This is assuming that you are
13 pumping more than you really need to cool the core.
14 MR. HALE: The flow rate assumptions are
15 associated about 2,000 gpm, I believe, for the RHR
16 pumps, which are in excess of what we needed. And we
17 ensured that under the EPU conditions we did not
18 deviate or change from the required flow rates. So,
19 we have the same required flow rates.
20 CHAIRMAN BANERJEE: And you have how much
21 flow area in your screens right now?
22 MR. HALE: I believe it was 1900 square
23 feet. Let me --
24 CHAIRMAN BANERJEE: Core area?
25 MR. HALE: Yes.

1 CHAIRMAN BANERJEE: Oh, okay.

2 MR. HALE: For each.

3 That summarizes what we wanted to talk

4 about with regard to the NPSH.

5 If you go to the next slide --

6 MR. KABADI: The regular?

7 MR. HALE: Yes. Yes, we are still in

8 backup, Jay.

9 MR. KABADI: Oh, still backup?

10 MR. HALE: Yes. We have got about four

11 slides here. Sorry. The next slide there. There you

12 go.

13 What we have actually done so far at Point

14 Beach in terms of improvements, we have implemented a

15 new strainer design on the units. That strainer

16 design was --

17 CHAIRMAN BANERJEE: These are these

18 strainers which are stacked up like that?

19 MR. HALE: These are the PCI sure-fall

20 strainers, 16th-inch diameter perforations. That is

21 what we have installed.

22 So, we have implemented those. We have,

23 as you can see there, a significant, as Larry had

24 mentioned previously, increase in the overall surface

25 area of the strainers.

1 We are definitely on a campaign to
2 eliminate all our fibrous insulation on both units.
3 Containment coating inspections, we do
4 that every refueling outage to ensure we control that
5 as a potential debris source.
6 DR. WALLIS: Now it is an old plant. Did
7 you have any coating or flaking when you bought the
8 plant? Did you find that there was any coating
9 problems?
10 MR. MEYER: No, not really.
11 DR. WALLIS: So, it had lasted all that
12 time?
13 MR. MEYER: We don't have any coating
14 issues to speak of.
15 MR. HALE: And we have also --
16 CHAIRMAN BANERJEE: Is it mainly qualified
17 coatings that you have or was this pre-qualification
18 type when it was done?
19 MR. HALE: The transition, originally, it
20 was pre-coating qualifications, but we have all had to
21 institute program associated with containment
22 coatings. In fact, it is also addressed as part of
23 license renewal, if you will recall, that coatings are
24 a big piece.
25 Inspections are done every outage. We

1 look at the coatings. The replacement coatings that
2 are put back on are qualified coatings. So, it is
3 part of our regular, normal maintenance and monitoring
4 for --
5 CHAIRMAN BANERJEE: Aluminum in
6 containment?
7 MR. HALE: I can't speak to how much we
8 have. I am not sure what we have at Point Beach.
9 DR. WALLIS: The new insulation is
10 reflective metal? Is that what it is?
11 MR. MEYER: Yes.
12 MEMBER SHACK: It is, hopefully, stainless
13 steel, not aluminum.
14 (Laughter.)
15 CHAIRMAN BANERJEE: Not aluminum for sure.
16 MR. MEYER: Any aluminum we have would be
17 evaluated. It would be a very small amount.
18 DR. WALLIS: How much fibrous insulation
19 did you take out? It sounds like a lot from the steam
20 generators and the pressurizer. That is a lot of
21 area.
22 MR. MEYER: Yes, I don't have the cubic
23 feet.
24 DR. WALLIS: Several truckloads, was it?
25 MR. MEYER: Oh, yes. Yes. Well, we have

1 done the steam generators. On Unit 1, we have got the
2 steam generators and the pressurizer, and we started
3 the loops. On Unit 2, this coming outage we will be
4 completing the pressurizer/steam generators and we
5 will start a loop.
6 So, at the end of the Unit 2 outage, which
7 is the one upcoming, both units will have the
8 pressurizer/steam generators done, and then what we
9 will have left will be driven by analysis, but I
10 imagine it is going to be the loops and then we will
11 have a bunch of small-bore piping as well to do.
12 CHAIRMAN BANERJEE: Do you have an
13 estimate of the radiation dose associated with --
14 MR. MEYER: Yes. Unfortunately, it is
15 pretty high because we have still got our RTD bypass
16 manifolds. And so, to do the small-bore piping on
17 Unit 1, the estimate is 160 RAM.
18 CHAIRMAN BANERJEE: And you need to do
19 that small-bore piping?
20 MR. MEYER: Pardon me?
21 CHAIRMAN BANERJEE: You need to --
22 MR. MEYER: Yes, I believe that, when all
23 is said and done, the testing will show we will need
24 to do that because our current insulation is among the
25 worst offenders.

1 CHAIRMAN BANERJEE: Yes.

2 MR. MEYER: But, then, we have got a
3 little extra time to plan that out, and with some
4 extra planning, with some special flushes, and maybe
5 by cutting out the RTD bypass manifolds, hopefully we
6 can get that dose down considerably. That would be
7 our goal. That is what I see as one of the biggest
8 advantages of having a little more time to get that
9 planned out to reduce the dose.

10 CHAIRMAN BANERJEE: Yes. So, you are
11 planning to spread this over what, a couple of
12 outages?

13 MR. MEYER: Yes. Yes, the overall plan
14 for us is that we are going to bring Unit 2 in
15 accordance with Unit 1 this year, and we are going to
16 finish our testing. And the testing will drive the
17 balance of the scope, but I believe that the balance
18 of the scope will be substantial. And, then, we will
19 take two cycles on each unit to complete the balance
20 of the scope. That is our overall plan.

21 I mean we have got a good jump on it. We
22 have got good experience with it now. We have removed
23 a lot of it.

24 Also, this outage, I should say, which is
25 also I think proactive on our part, is that we are

1 also doing laser scans in containment, so that we can
2 develop all of the work packages to remove the
3 insulation from the small-bore piping.
4 So, what that does is it will give us like
5 the exact dimensions and everything, so that we can
6 get all of that all planned out. And so, we are doing
7 all those laser scans this coming outage, and that
8 will give us more accurate work plans for the rest of
9 the installation that has to be replaced. And so all
10 of that will be done this year.
11 DR. WALLIS: You had 21 square feet of
12 strainer before?
13 MR. MEYER: Yes.
14 DR. WALLIS: That is about the size of a
15 garbage can?
16 MR. MEYER: It was like one module, you
17 know.
18 DR. WALLIS: Yes.
19 MEMBER SHACK: What is your chemical for
20 pH control in the sump?
21 MR. HALE: It is sodium hydroxide.
22 MEMBER SHACK: Sodium hydroxide.
23 MR. HALE: NaOH.
24 CHAIRMAN BANERJEE: That is why aluminum
25 is particularly an issue. And your ZOI is calculated

1 on the basis of the EPU right now?

2 MR. HALE: Yes.

3 CHAIRMAN BANERJEE: And you are using the

4 sort of, I guess, ANSI model, must be, whatever the

5 staff has agreed to.

6 MR. HALE: Yes.

7 CHAIRMAN BANERJEE: Yes.

8 DR. WALLIS: I would think if you are

9 going up to the pressurizer, you might as well take it

10 all off. So, you don't get into debates about how big

11 the ZOI is and that sort of thing. Just take it all

12 out. Once you take some of it out, isn't it just as

13 easy to keep going and take it all out?

14 MR. MEYER: That is where we might end up.

15 That is where we might very well end up. In fact, we

16 have got our own analysts, and that is a possible

17 outcome. I would say it is somewhat likely.

18 CHAIRMAN BANERJEE: The whole industry is

19 trying to get perhaps -- there is a testing program to

20 reduce the ZOI, if possible. You don't know that

21 outcome.

22 MR. MEYER: Well, we are using the 17

23 diameters, right?

24 CHAIRMAN BANERJEE: Yes.

25 MR. MEYER: So, that is what we are

1 committed to.

2 CHAIRMAN BANERJEE: Right.

3 MR. MEYER: We feel that is the right

4 value.

5 CHAIRMAN BANERJEE: Yes.

6 DR. WALLIS: Until someone comes along and

7 says it is a concentrated jet and not a sphere. Oops.

8 CHAIRMAN BANERJEE: Let's not go there.

9 Okay?

10 DR. WALLIS: It is aimed at the

11 pressurizer.

12 CHAIRMAN BANERJEE: Okay. I think it is

13 fine.

14 MR. MEYER: For our plant, you know, it is

15 four years and then it is going to go another twenty

16 on each unit, and then even more.

17 CHAIRMAN BANERJEE: Maybe there is life

18 after 60, right?

19 MR. MEYER: And so, that insulation, just

20 because of age, at some point needs to be replaced.

21 And so, why not replace it? And, then, at the same

22 time, it is a safer plant.

23 CHAIRMAN BANERJEE: You didn't know this

24 when you replaced the steam generators.

25 MR. MEYER: Yes, yes.

1 CHAIRMAN BANERJEE: Okay.

2 MR. HALE: All right. Briefly, what we
3 identified here is what we are going to be doing
4 during the spring 2011 outage for Unit 2 on the RCP
5 VALET and then some portion of the pressurizer.

6 CHAIRMAN BANERJEE: The other reason it
7 may be prudent is that it would suddenly reduce
8 downstream effects to take the fibrous stuff out.

9 MR. HALE: Yes.

10 CHAIRMAN BANERJEE: So, I mean, at the
11 moment, it is a sump screen issue, but it may shift at
12 some point to close that whole issue. So, I think it
13 is a prudent move to do this anyway. Okay?

14 MR. MEYER: Yes, we agree. We are
15 committed to do it.

16 MR. HALE: As far as our path going
17 forward in terms of GSI-191, we are going to continue
18 to follow the testing this year and the various
19 aspects of that testing. And, then, the first quarter
20 of next year, we will be developing a plan that is
21 consistent with the development and guidance in the
22 Commission SRM and looking at various closure options
23 in our plan to ensure that we get it closed out --

24 DR. WALLIS: Now is there some industry
25 testing that is specific to your plant?

1 MR. HALE: I can't answer that question.
2 I would think it is pretty much generic.
3 CHAIRMAN BANERJEE: Sorry. What is the
4 question?
5 DR. WALLIS: If the testing is specific to
6 their plant. As I understand it, sometimes they have
7 to do specific tests for specific plants because the
8 kind of debris is different from plant to plant.
9 CHAIRMAN BANERJEE: No, I think you are
10 doing plant-specific testing, yes.
11 MR. MEYER: Yes.
12 DR. WALLIS: In which case, as you start
13 taking some out, you have a different load to test.
14 CHAIRMAN BANERJEE: Well, I think you have
15 targets, right? I mean you have a path forward
16 clearly.
17 DR. WALLIS: Then there is always a
18 question about whether having less fiber is bad or
19 good.
20 (Laughter.)
21 CHAIRMAN BANERJEE: No, less fiber is I
22 think always --
23 MEMBER SHACK: For human beings, less
24 fiber is better.
25 DR. WALLIS: You have less stuff and it is

1 worse.

2 CHAIRMAN BANERJEE: Anyway, all right.

3 Yes, what he is saying is that, if you don't have some

4 fiber or something on your screens, you tend to pass

5 more stuff through --

6 MEMBER SIEBER: Everything goes through.

7 CHAIRMAN BANERJEE: -- to the downstream.

8 So, it shifts the --

9 DR. WALLIS: There is also this thin bed

10 thing.

11 CHAIRMAN BANERJEE: Yes.

12 DR. WALLIS: A little bit of fiber can be

13 worse than having a lot of fiber because it

14 concentrates the particles.

15 CHAIRMAN BANERJEE: But I assume that you

16 discussed your testing program with the staff and you

17 have agreement. We were very involved in developing

18 the guidance, but we are not really involved with

19 everything.

20 MR. MEYER: Sure. I can tell you that at

21 Point Beach we have an extraordinarily strong safety

22 culture.

23 CHAIRMAN BANERJEE: Yes.

24 MR. MEYER: Like a nuclear safety culture.

25 And I have engineers, senior engineers, that are

extraordinarily committed to get this right and use the conservatism in the analysis, and they hold the organization accountable. So, I am proud of that.

DR. WALLIS: That sounds good. Now do you have metrics for the safety culture? How do you know?

(Laughter.)

MR. MEYER: Well, yes, actually, what we do is we do a lot of surveys. And so, maybe we have too many surveys.

(Laughter.)

So, in 2010, we had something called an engagement survey, which is very well-designed. We had an independent safety culture survey. We had an organizational culture index survey. And, then, we have something in NextEra called the Nuclear Excellence Model. In those areas and in the anecdotal feedback that we get from our workers, the Point Beach plant scores highest in the fleet.

MR. HALE: Okay. One more slide there, Jay.

We thought it would be worthwhile, also, to discuss the EPU relative to our current plan with GSI-191 resolution.

CHAIRMAN BANERJEE: So, you are basically planning your GSI strategy based on the EPU?

1 MR. HALE: Assuming the EPU, but we
2 thought it was worthwhile to identify a couple of
3 areas. You know, it didn't have any effect on our
4 insulation, our debris generation. We are not
5 affecting the sump flows. We are maintaining flows as
6 they are currently.
7 There will be some slight effects on sump
8 temperature, okay, an effect which we have already
9 discussed. But those have already been accommodated
10 in the evaluations and analyses that are being
11 discussed and reviewed with the staff.
12 And, then, we talked about the boron
13 concentration already with regard to boron
14 precipitation.
15 CHAIRMAN BANERJEE: Where the EPU will, of
16 course, affect things is with downstream effects --
17 MR. HALE: Right.
18 CHAIRMAN BANERJEE: -- because you need a
19 somewhat higher flow because the decay heat level will
20 be higher by 18 percent. But that is what you are
21 planning, right?
22 MR. HALE: No. With regard to the flows,
23 we were able to stay within our current design, the
24 current flow.
25 CHAIRMAN BANERJEE: Yes, but by downstream

1 effects, I mean if there is in-vessel blockage.

2 MR. HALE: Okay.

3 CHAIRMAN BANERJEE: Okay? So, the issue

4 there becomes, how much pressure loss can you take

5 over the blockage? You have to have a certain flow,

6 so that you don't get boron precipitation on fuel rods

7 and loss of cooling, and all that sort of stuff. So,

8 you are going to need 20 percent more flow through the

9 EPU.

10 But I am assuming that in your planning

11 your experiments or when you go to resolve GSI-191,

12 taking the PWROG's results, you will be able to show

13 that you stay within whatever the boundaries of the

14 work there.

15 MR. HALE: Yes. Yes.

16 CHAIRMAN BANERJEE: And that you will have

17 sufficient flow.

18 MR. HALE: Yes.

19 CHAIRMAN BANERJEE: But I think that is a

20 separate issue, GSI-191 resolution. You are behaving

21 as if you have got the EPU.

22 MR. HALE: I guess that's --

23 CHAIRMAN BANERJEE: Yes, that is the way I

24 see it because that is what you are going to, then,

25 have to resolve. You can't do it pre-EPU because,

1 then, you have to do it --

2 MR. HALE: Right.

3 CHAIRMAN BANERJEE: -- sort of post-EPU.

4 MR. HALE: Exactly.

5 CHAIRMAN BANERJEE: Yes.

6 MR. HALE: That is exactly correct.

7 CHAIRMAN BANERJEE: The concern is

8 primarily, I would say, with in-vessel effects because

9 you have got a higher decay heat now --

10 MR. HALE: Yes.

11 CHAIRMAN BANERJEE: -- to deal with. So,

12 one concern, of course, was with the NPSH.

13 MR. HALE: yes.

14 CHAIRMAN BANERJEE: Which I think you have

15 shown that you have margin there. That is not an

16 issue probably.

17 And, then, the second concern is with

18 downstream effects, in-vessel downstream effects, not

19 the pumps, because you have a higher decay heat level.

20 Does that make sense, what I am saying?

21 MR. HALE: I think I understand it.

22 CHAIRMAN BANERJEE: Yes. Okay.

23 MR. HALE: On the GSI-191, you know, we

24 have supplied, we can certainly bring our experts on

25 GSI-191, of course, here.

1 CHAIRMAN BANERJEE: But this is an ongoing
2 process.
3 MR. HALE: Right.
4 CHAIRMAN BANERJEE: And you are going to
5 have to resolve this for the EPU anyway.
6 MR. HALE: Yes.
7 CHAIRMAN BANERJEE: I mean that is a
8 separate issue the staff is looking at, right, the
9 resolution of GSI-191?
10 MR. HALE: Exactly.
11 CHAIRMAN BANERJEE: Yes.
12 MR. HALE: Exactly.
13 CHAIRMAN BANERJEE: Okay. Go ahead.
14 MR. HALE: All right. Well, that was what
15 we had provided.
16 You can go back to the regular slides,
17 Jay.
18 CHAIRMAN BANERJEE: Remind me now your
19 alignment. You have worked two injection points
20 already, right?
21 MR. HALE: Right.
22 CHAIRMAN BANERJEE: So, you don't have to
23 realign any injection?
24 MR. HALE: No.
25 CHAIRMAN BANERJEE: Okay.

1 MR. HALE: No, in fact, we don't have to
2 -- whether you are in a small-break or large-break
3 scenario, you never stop flow to the core, which I
4 think is a real positive feature in design at Point
5 Beach. In other words, if you are on high-pressure
6 injection, you can realign the RHR pumps in a
7 piggyback configuration without stopping high head
8 injection flow, and then we can do the same if we are
9 in the large-break LOCAs.
10 CHAIRMAN BANERJEE: You seem to have a lot
11 of high head injections flow.
12 MR. HALE: Yes, we do. Our pumps are
13 significantly large compared to, say, some of our
14 other plants.
15 CHAIRMAN BANERJEE: Right.
16 MR. HALE: Which is a positive effect as
17 well.
18 CHAIRMAN BANERJEE: All right.
19 MR. HALE: Okay. Moving on to containment
20 peak pressure for a main steamline break, Jay, go on
21 to the next one.
22 For main steamline break, we used LOFTRAN
23 for our mass and energy release calculation and GOTHIC
24 for containment analyses.
25 One thing we did implement, as we have

1 mentioned previously, is fast-acting feedwater
2 isolation valves, which is a significant upgrade for
3 us. Originally, we had a feed reg valve and then
4 tripping the pumps as our means for terminating feed
5 flow. Now we have a fast-acting valve and a feedwater
6 reg valve as our two primary boundaries for isolating
7 flow.
8 And, of course, we have got the new AFW
9 system. So, we have got additional flow there. I
10 mean in terms of our assumptions, we assumed higher
11 flows for main steamline break, which bound the
12 increase in flows in our RFW system.
13 And as you can see there, we actually have
14 a peak pressure reduction for main steamline break.
15 The primary reason for that is the fact of the
16 feedwater isolation valves. So, our feedwater
17 addition during main steamline break was significantly
18 greater before the EPU than it will be after the EPU.
19 So, we are actually showing a benefit in terms of
20 high containment.
21 MEMBER SIEBER: I have never seen a feed
22 reg valve that didn't leak when it was closed. I
23 presume that your original feed reg valves were the
24 same way, right?
25 MR. HALE: Yes, yes.

1 MEMBER SIEBER: So, you really didn't
2 isolate the main steam header totally?
3 MR. HALE: This is feedwater? Yes.
4 MEMBER SIEBER: Steam. Steamline, or
5 feedwater, right.
6 MR. HALE: Yes, feedwater lines. And,
7 really, you are trying to terminate a mass flow
8 addition. Okay? So, what we are talking here is they
9 don't necessarily have to be leak-tight. You just
10 want to make sure you terminate the mass flow that is
11 being run into the steam generators.
12 MEMBER SIEBER: Well, now you have tight-
13 closing valves?
14 MR. HALE: That is right.
15 MEMBER SIEBER: Or you will have.
16 MR. HALE: Right. So, a significant
17 benefit to the feedwater isolation valves.
18 MEMBER SIEBER: Well, and the integrity of
19 the whole system.
20 MR. HALE: Right. Right.
21 MEMBER SIEBER: Because, otherwise, you
22 don't have integrity.
23 MR. HALE: Okay, the next slide.
24 And that does it for me, I think, for
25 today.

1 CHAIRMAN BANERJEE: Now okay. We now go
2 with the staff, is that right?
3 DR. BONACA: Before you leave, I had a
4 question.
5 MR. HALE: Yes?
6 DR. BONACA: You had a statement here.
7 The inadvertent opening of the pressurizer PORV is not
8 near design basis. And therefore, you did not analyze
9 the transient. But I am sure you trained the
10 operators on that kind of transients.
11 MR. HALE: Sure. Yes, definitely.
12 DR. BONACA: So, you do have means of
13 modeling that?
14 MR. HALE: Yes.
15 DR. BONACA: Okay.
16 MR. HALE: Whether it is in the design
17 basis or not would not necessarily establish whether
18 we evaluate it. We have operational procedures to
19 address design basis as well as beyond design basis
20 events.
21 DR. BONACA: Yes. No, I understand that.
22 MR. HALE: And also, a PORV, inadvertent
23 opening of a PORV is also an item we would have to
24 address under fire protection in terms of spurious
25 actions, high-pressure, low-pressure interface.

1 DR. BONACA: Okay. So, there is a clear
2 understanding of the operators about the sequence?
3 MR. HALE: Yes, yes. That is correct.
4 CHAIRMAN BANERJEE: So, I just wanted to
5 get our agenda straight here. The way we have got it
6 here, now the staff will come, and then we go into
7 closed session after that, after a break. And, then,
8 we go into various other safety analyses.
9 MR. HALE: Yes, I think we are done. Jay
10 and are.
11 CHAIRMAN BANERJEE: Oh, you are done?
12 MR. HALE: Yes. So, I think it is up to
13 the staff.
14 CHAIRMAN BANERJEE: So, this is just
15 closed session of followup? So, the rest of today
16 would be the staff because, the way we have got it
17 scheduled, it is tomorrow that we do the electricals,
18 the probabilistic --
19 MR. HALE: Right.
20 CHAIRMAN BANERJEE: -- safety analysis,
21 because we have --
22 MR. HALE: Yes, this is just our agenda.
23 CHAIRMAN BANERJEE: -- yes -- another
24 member, John Stetkar, who will be here in the morning.
25 DR. WALLIS: You have a couple of action

1 items. Are you going to come back to that?
2 MR. HALE: Yes. I believe the staff is up
3 next.
4 CHAIRMAN BANERJEE: Yes, the staff is up
5 next, and, then, we will have some --
6 DR. WALLIS: The action items will keep us
7 here until seven o'clock.
8 MR. HALE: No, hopefully not.
9 (Laughter.)
10 CHAIRMAN BANERJEE: I have to go to the
11 gym. So, we will terminate it.
12 MR. HALE: No, we are currently getting
13 those answers. I think we have some of the answers
14 already. But what we would like to do is come at the
15 end of the session today and go through and address
16 the action items.
17 CHAIRMAN BANERJEE: Right. So, we won't
18 have things spilling over necessarily. Let's see how
19 it goes, but --
20 MR. HALE: Right.
21 CHAIRMAN BANERJEE: -- we will just go
22 into the agenda tomorrow as it stands.
23 MR. HALE: Right.
24 CHAIRMAN BANERJEE: Because, as I said, we
25 have another member who will be coming for the

electrical probabilistic safety assessment.

MR. HALE: Now, if I am not wrong, Terry, the closed session, was that for proprietary information?

MR. BELTZ: Right. That is the reason we had that time scheduled.

MR. HALE: We have not gotten into any proprietary.

CHAIRMAN BANERJEE: You don't need that.

MR. HALE: Yes, I don't think we will need it from our perspective.

CHAIRMAN BANERJEE: If we need it, we can do it. All right?

Okay. So, thank you very much. We really appreciate it, and thank you for your very nice presentations today. It clarified a lot of things.

And now we will go into the staff's session. And we have got the slides, right? Yes.

We will go ahead and, depending on what is a natural time, we will take a break and work that out the way you like.

Okay, Terry, it is in your hands again.

I see some old friends up there.

MR. PARKS: Good afternoon.

My name is Ben Parks, and I am here with

1 the Reactor Systems Branch in NRR, joined by Sam
2 Miranda, also in the Reactor Systems Branch, and Len
3 Ward from the Nuclear Performance and Code Review
4 Branch.
5 We are going to discuss the safety
6 analysis and, more specifically, our review of it for
7 the Point Beach EPU.
8 The general process that we are going to
9 follow here is to discuss our review procedures, give
10 you an overview of results. We plan to spend the bulk
11 of our time talking about these challenging review
12 areas, and then we will discuss our review conclusions
13 with you.
14 As far as process is concerned, we
15 followed Review Standard 001, the review standard for
16 extended power uprates. We checked to ensure that the
17 analytic methods that Point Beach used were used
18 consistently with their NRC approval. We compared the
19 results to similar plants. That would have been Ginna
20 and Kewaunee.
21 We applied additional review effort to
22 these challenging review areas, which would have been
23 the steamline break, boric acid precipitation
24 analysis, and the steam generator tube rupture event.
25 When I say "challenging", what I mean is we had to

1 issue multiple rounds of RAIs, perform in some cases
2 independent calculations, and we also conducted some
3 audits and site visits to ensure that Point Beach
4 would be implementing their EOP in a manner consistent
5 with NRC requirements.
6 Speaking generally, we found that most
7 results of their safety analysis were acceptable.
8 They were performed in accordance with NRC-approved
9 methodology, and the results were acceptable and they
10 showed adequate margin to our acceptance criteria or
11 regulatory limits.
12 DR. BONACA: Did you perform some
13 benchmark calculations?
14 MR. PARKS: I'm sorry?
15 DR. BONACA: Did you perform some
16 comparative calculations in some cases?
17 MR. PARKS: For the small-break LOCA and
18 the boric acid precipitation calculations, we did,
19 yes.
20 DR. BONACA: Okay.
21 MR. PARKS: Some of the events -- I think
22 that you have already discussed this this morning --
23 were identified as outside the Point Beach design
24 basis. When we encountered that in cases, we
25 questioned it. We requested that Point Beach provide

us additional information, in some cases postulating what the results of the event would be, and we performed our own independent engineering assessment. We looked at similar plants to see if the fact that Point Beach had not analyzed a particular event posed a safety concern. And we satisfied ourselves in most cases that it did not.

Three events required more detailed evaluation.

Terry, take us to the next slide.

Those would have been the main steamline break that Sam is going to discuss with you, the post-LOCA boric acid precipitation that Len will discuss with you, and I will discuss the steam generator tube rupture.

So, at this point, I will turn it over to Sam to talk about the steamline break.

MR. MIRANDA: The steamline break, first, I would like to start off by saying that, as far as Point Beach is concerned, there is not a problem with the main steamline break. This topic was selected as one of the more challenging aspects of the review, and you will see by the time I am through that there are some, I would say, perhaps philosophical concerns about steamline break.

1 The first thing to be noted for Point
2 Beach is that Westinghouse's topical report on main
3 steamline break, WCAP-9226, does not apply to two-loop
4 plants. This topical was written in 1978, and it was
5 filled with sensitivity studies to consider the
6 effects of power levels, break size, mixing in the
7 reactor vessel, and other things that would provide
8 information needed for licensing reports that would
9 satisfy concerns about whether the worst case had been
10 identified.
11 And the bottom line for WCAP-9226 was one
12 particular curve of interest which was minimum DNB
13 ratio versus break size. And that is a proprietary
14 curve. You are not going to see it. But it is
15 sufficient to say that the larger the break size, the
16 lower the minimum DNB ratio.
17 As I said before, this does not apply to
18 two-loop plants. The sensitivity studies performed
19 were based on a three-loop plant and also applied to
20 four-loop plants.
21 During the review, the NRC asked them,
22 asked Westinghouse, well, what about two-loop plants?
23 And Westinghouse said, well, we didn't have to do
24 them for two-loop plants because there were no two-
25 loop plants in the licensing process that would be

1 affected by this. They were all older than the
2 requirements in question. They were talking about Reg
3 Guide 1.70, the standard format for licensing
4 submittals.
5 So, basically, they pointed the question
6 to the future. Well, this is the future.
7 And Point Beach came in with steamline
8 break analyses. Basically, I had to think about,
9 well, what can I use instead of WCAP-9226? So, 9226,
10 which was written in 1978, pertained to plants that
11 are quite different from the plants that are use in
12 today.
13 In 1978, plants had boron injection tanks
14 which had high-concentration boron, and during a
15 steamline break, once safety injection was actuated
16 and this high-concentration boron entered the core,
17 the reactivity dropped like a rock. And based on this
18 and also an internal Westinghouse criterion,
19 acceptance criterion, that did not allow the credible
20 break to go critical, WCAP-9226 never considered the
21 credible break.
22 The credible case, in case you are not
23 familiar with it, is the anticipated operational
24 occurrence version of the steam break, which is the
25 opening of a steam site valve, like a condenser dump

1 valve or a relief valve.

2 So, it is considered as a very small

3 break. And as such, as a very small break, it doesn't

4 actuate the parts of the reactor protection system

5 that would be invoked by a larger break.

6 And the most important of these is

7 steamline isolation, which is actuated by high

8 steamline flow. The credible break is not large

9 enough to do that. The credible break has to wait for

10 some other signal. Usually, that is low-pressurizer

11 pressure.

12 So, comparing a credible break to a larger

13 break is very difficult because they act on different

14 parts of the reactor protection system.

15 So, I was interested in understanding how

16 they handled the credible break. Well, the Point

17 Beach FSAR, just like almost every other FSAR you will

18 find today, when you go to the section on credible

19 break, all you find is a paragraph that says: we

20 didn't analyze this case because it is bounded by the

21 larger breaks.

22 If you look at WCAP-9226, and if you

23 consider the conditions at the time this was written

24 in 1978, this was true, that since the credible break

25 never even returned to critical, you can just write it

1 off.

2 But today that is different. Today,
3 without the high-concentration boron, and without
4 steamline isolation, the credible break very often
5 returns to critical. And since it is protected by
6 different parts of the reactor protection system, it
7 is not clear whether or not the credible break would
8 be bounded by the larger breaks.

9 In Point Beach's case, it is. The
10 reasoning I used for Point Beach was this: the
11 credible break, if it were to occur at Point Beach,
12 and there were no protection provided at all, then the
13 core power, should the core return to critical, the
14 core power would not be any higher than about 10
15 percent, since that is the capacity of the largest
16 valve in the secondary side.

17 So, if one valve opens, it relieves 10
18 percent nominal steam flow. The core power would be
19 about 10 percent.

20 If I look at the major steamline break, as
21 analyzed by Point Beach, the core power reaches levels
22 greater than 20 or 25 percent. Therefore, it is
23 bounded.

24 I raise this issue because this is not
25 true in all plants. However, if you go to just about

1 any Westinghouse FSAR and you look at the section on
2 credible break, you will find that paragraph that says
3 it is bounded. And I think it outdated.
4 Yes?
5 MEMBER SIEBER: Is the staff going to do
6 anything about these other plants that aren't bounded?
7 MR. MIRANDA: Yes. Well, I will. As a
8 reviewer, I will know which plants are not bounded
9 when they come in, and I will ask questions like
10 these.
11 MEMBER SIEBER: Yes, but if they don't
12 come in, nobody is going to check, right?
13 MR. MIRANDA: Yes, that's true, but
14 eventually they all come in for something.
15 (Laughter.)
16 CHAIRMAN BANERJEE: Do you have a comment
17 on this?
18 MR. ULSES: Yes. This is Tony Ulses.
19 MEMBER SIEBER: I need say no more, right?
20 CHAIRMAN BANERJEE: Tony is going to say
21 something.
22 MR. ULSES: I just want to add in there
23 that we have processes internally for evaluating such
24 situations, and we are taking a look at it. And at
25 this point, it is a little premature to see where we

1 will go on this. But, for this particular case, I
2 think the point we are trying to make here is that the
3 conclusion is that what is stated in the FSAR is okay,
4 yes.
5 MEMBER SIEBER: Thank you.
6 MR. MIRANDA: And this slide here
7 summarizes what I just said. The credible break does
8 not lead to steamline isolation, which in my opinion
9 is the most effective protection for steamline break,
10 steamline isolation. And depending upon the location
11 of the break, that ends the accident.
12 If a steamline isolation valve should
13 fail, and we do assume that one fails during accident
14 analyses, then, at most, you will have one steam
15 generator blowing down. And when that steam generator
16 is empty, the accident is effectively over. So, that
17 is what I mean by self-limiting. The accident is over
18 when the steam generator is dry.
19 Another thing that I noticed in Point
20 Beach, and this is also true of other plants, if the
21 reactor coolant system pressure drops low enough due
22 to the depressurization from the overcooling of the
23 system, if it drops low enough, you will get
24 accumulator injection.
25 MEMBER SIEBER: Right.

1 MR. MIRANDA: And that is a legitimate
2 form of protection. It is safety grade. The
3 accumulators are there. They will inject.
4 I had a little bit of a concern that
5 accumulators are there for LOCA, not for steamline
6 break. And I would have liked to see something that
7 didn't have an accumulator injection.
8 So, I asked the licensee, well, show me a
9 smaller break. Show me something that doesn't
10 depressurize down to the level of the accumulator set
11 pressure.
12 MEMBER SIEBER: Which is 600 pounds,
13 right?
14 MR. MIRANDA: In Point Beach, it is 700,
15 yes.
16 MEMBER SIEBER: Okay.
17 MR. MIRANDA: And I didn't like the answer
18 I got. I was told that every break size will
19 eventually get there; the smaller break size will take
20 longer.
21 MEMBER SIEBER: As soon as you empty the
22 condensate storage tank.
23 MR. MIRANDA: I didn't believe that
24 because I have seen breaks that didn't reach the
25 accumulator injection set pressure. And they were

1 quite common for the credible breaks. These days it
2 is kind of hard to find a credible break analysis.
3 They are not reported anymore.
4 But I found one for Point Beach that was
5 done in 1990. I think that is the next slide. And
6 this is a credible break at Point Beach, 1990. This
7 was before they changed the steam generators in Unit
8 2, but that would not really affect this.
9 MEMBER SIEBER: That's right.
10 MR. MIRANDA: But you can see from this
11 curve of reactor coolant system pressure for a failed
12 relief valve that the reactor coolant system pressure
13 doesn't get below 750.
14 MEMBER SIEBER: Right.
15 MR. MIRANDA: I asked Westinghouse about
16 the effect of the accumulator injection, and they did
17 an analysis of a large break. They just wired out the
18 accumulator. It just didn't exist.
19 The results indicated that the DNBR,
20 minimum DNBR, was lower, but not much lower. It was a
21 small effect.
22 MEMBER SIEBER: Right.
23 MR. MIRANDA: So, on that basis, I was
24 satisfied.
25 MEMBER SIEBER: I agree.

1 CHAIRMAN BANERJEE: How much was the
2 effect on DNBR?
3 MR. MIRANDA: I was told it was something
4 less than 3 percent.
5 MEMBER SIEBER: Yes. Right.
6 MR. MIRANDA: So, these are the kinds of
7 questions I will be asking of the other plants when
8 they come in for licensing actions.
9 MEMBER SIEBER: Okay.
10 CHAIRMAN BANERJEE: Thank you.
11 MR. WARD: My name is Len Ward. I was
12 going to talk about boric acid, post-LOCA long-term
13 cooling in boric acid precipitation.
14 As everybody knows, power uprates, higher
15 power level will mean that if you are boiling in the
16 core and adding boric acid, it is going to shift it to
17 earlier times. So, we wanted to take a close look at
18 that and make sure that we understood completely what
19 the licensee did.
20 I guess, before I get into it, just to
21 talk about the ECCS design, they have 695 psia
22 accumulators, low-pressure injection pumps that inject
23 directly into the upper plenum, and high-pressure
24 safety injection that goes into the cold legs.
25 The key here is they are a little

1 different than standard plants to control boric acid.
2 This system, they will terminate high head safety
3 injection when the RWST drains. So, that will leave
4 the low-pressure pump injecting.
5 So, you are not injecting on the cold
6 side. If you were injecting on the cold side and you
7 had a break on the hot side, you would build up a head
8 of water on the cold side. It would flow through the
9 core and spill the fluid out the break in the hot leg.
10 We don't have that here.
11 High pressure is gone. So, low pressure
12 is on. So, that makes the hot leg break limit. If
13 there was a cold leg break, the hot leg, the hot side
14 injection would fill the system up and push the fluid
15 out the cold side.
16 So, that is a key ingredient here. That
17 is why the hot leg breaks are limiting for
18 precipitation.
19 When all of the ECCS systems are
20 operating, you get a 20-minute switch time from the
21 injection mode, which is drawing from the RWST, to the
22 sump. You have got to switch suction from these pumps
23 to the sump. And that occurs at 20 minutes.
24 So, then, prior to that point, there is
25 flow coming in from the LPSI and HPSI pumps. It fills

1 the system up quite rapidly. You throw those
2 accumulators in there.
3 As a matter of fact, I ask the licensee to
4 show some results of some calculations. What is the
5 behavior in the first 20 minutes? Are you flushing?
6 And they do COBRA/TRAC calculations. And within 200
7 seconds, the LPSI pump was putting in like 100 pounds
8 per second, 60 to 100 pounds per second, and the LPSI
9 was pumping in a very large amount. At 200 seconds,
10 there was basically 200 pounds of liquid going out the
11 break. So, the system is full.
12 With those kinds of flow rates, you are
13 not going to build up boric acid. So, basically, at
14 the end of 20 minutes, you have a concentration in the
15 vessel which is comparable to the sources, which is
16 3200 ppm.
17 So, the key ingredient here, then, is to
18 reinitiate high-pressure safety injection into the
19 cold side, so you can fill the system up and push this
20 stuff out the hot leg.
21 Now small breaks, most people think that
22 boric acid control is only a large-break concern. It
23 is a small-break concern as well. And I just will
24 mention that briefly.
25 There was a detailed analysis they did of

1 breaks from roughly 1 square foot all the way down to
2 1 inch to look at small breaks. It is basically very
3 similar, almost the same as that which was done for
4 the Ginna plant. This is much the same plant.
5 But what you do, since the pressure is
6 high, in the system for small-break you can't always
7 assure that you can put enough in the cold side or the
8 hot side, depending on whether the break is on the
9 cold or hot side, so that you have enough excess flow,
10 called flush flow, to flush the core.
11 So, what do you do? You have to
12 demonstrate that you can fill the system with liquid,
13 completely fill it, and reestablish single-phase
14 natural circulation and disperse the boric acid that
15 way. And that is what they did, what they do.
16 The key ingredient there to assure that
17 that happens is that the EOP has an instruction to the
18 operators to initiate a cooldown no later than one
19 hour. So, that will, when you start cooling down the
20 break size big enough, you may get the low pressure
21 on, in which case you will fill up faster. If not,
22 you still have low-pressure injection, and that will
23 fill you up.
24 And I think once you get down around 1
25 inch or smaller, you are not losing single-phase

1 natural circulation very long. If you do, you fill it
2 back up.
3 And basically, what you do is any boric
4 acid that is concentrating for the first three or four
5 or five hours, depending on break size, it will be
6 dispersed. The saving grace is you can get a lot of
7 boric acid in the system, but because this system is
8 at higher temperatures, 250 to 300 degrees, your
9 precipitation limit is up near 50 percent.
10 So, you just want to make sure that in the
11 analysis they cool down, the system refills, and you
12 disperse it. And they demonstrated that. We even did
13 RELAP5 calculations to confirm a spectrum of breaks
14 for that.
15 Now we are going to focus on large-break
16 LOCA. That is where all the action is.
17 The key ingredient in this, as everybody
18 knows, and I think it was discussed, is the mixing
19 volume. I did calculations with my model and compared
20 it to what Westinghouse had done. This has happened
21 many times in the past.
22 But the mixing volume we both use is you
23 have the core, half the lower plenum, and the upper
24 plenum below the hot leg elevation. Because the void
25 fraction coming off the surface of the core is roughly

in this one two-hour frame, it is around 80 percent, there is not a lot of liquid up there, even though there is a large volume. So, that doesn't play a big role. But, nevertheless, it is part of the volume.

So, the key is the mixing volume is half the lower plenum in the core and just a small slice of upper plenum below the bottom elevation of the hot leg.

Another important assumption, probably the biggest conservatism, is the use of the 1971 ANS decay heat standard with a 20 percent multiplier. I mean that means the core is pumping out basically 20 percent more power. It is going to build up boric acid really fast.

The mixing volume is time-dependent. Westinghouse used a WCOBRA/TRAC model to calculate theirs, and I had my own model, which is a drift-flux model using correlations from one-dimensional two-phase flow.

CHAIRMAN BANERJEE: So, you sort of wrote your own model?

MR. WARD: Yes, it is simple. Basically, I balanced the heads between the downcomer and the inner vessel where the core is with the loop resistance. It is quasi-steady. But I describe, I

1 calculate the distribution of steam below the two-
2 phase surface using a drift-flux model.
3 CHAIRMAN BANERJEE: Keep that model for
4 GSI-191 as well.
5 MR. WARD: Did I?
6 CHAIRMAN BANERJEE: Put a little
7 resistance in the core and --
8 MR. WARD: We could do that. It is
9 possible.
10 CHAIRMAN BANERJEE: Yes.
11 MR. WARD: You could do anything you want.
12 But because in this case the break is in
13 the hot leg, there is very little -- the resistance is
14 from the --
15 CHAIRMAN BANERJEE: That is the limiting
16 scenario for in-vessel effects.
17 MEMBER SIEBER: Right.
18 MR. WARD: Yes. Okay. Right. Okay.
19 CHAIRMAN BANERJEE: For this plant anyway.
20 MR. WARD: Yes. Okay. Okay.
21 Then, just the RWST and the accumulators
22 have concentrations of 3200 ppm.
23 CHAIRMAN BANERJEE: So, you are assuming
24 some entrainment, of course, or not?
25 MR. WARD: No, I am not throwing any boric

1 acid out of the system. The steam is not, the vapor
2 is not taking it away, and I am not throwing it away.
3 There is entrainment during this. I mean,
4 if you look at UPTF, 40 percent of the liquid is
5 thrown out into the hot legs and into the steam
6 generator. I am keeping it all there. No boric acid
7 leaves. It is whatever goes in stays there. And it
8 is at 14.7 psia, and we know the containment pressure
9 is probably a little higher. I will get there in a
10 minute.
11 The vendor calculated four hours and 50
12 minutes for the licensee for precip time, and in my
13 model I got four hours and 25 minutes. So, it is
14 pretty close.
15 Can you jump to the next slide real quick?
16 DR. WALLIS: Could you tell me more about
17 it will all stay in the core? Some of it does go
18 around.
19 CHAIRMAN BANERJEE: It does in reality.
20 DR. WALLIS: It goes around the loops, and
21 quite a lot does.
22 MR. WARD: Well, I mean the only water in
23 the vessel, it is a double-ended hot leg break. So,
24 the boric acid, the boron in the liquid is entering
25 the core and it is boiling and it is staying, steam

1 vapors disengaging and flowing out the break.

2 CHAIRMAN BANERJEE: He is not taking

3 entrainment.

4 MR. WARD: I am not. I am not, and the

5 vapor is not carrying liquid in it and throwing it. I

6 mean that is what happens, but I am not doing that. I

7 didn't do that. I don't want to reduce the -- I want

8 to see what happens if it all stays in there.

9 DR. WALLIS: That's right. I was just

10 wondering how unrealistic it is.

11 MR. WARD: Well, like I said, the UPTF

12 test for large-break LOCAs, they looked at, you get

13 30-40 percent.

14 DR. WALLIS: A lot of it goes out.

15 MR. WARD: Thirty or 40 percent gets

16 thrown out. I mean it takes a while before you can

17 get enough fluid in the core to turn the temperature

18 on a large-break LOCA. You are throwing liquid out.

19 It is entrained. It is going out.

20 So, that is what delays the quenchment

21 propagation, right? But this is strictly a boric acid

22 buildup thing. So, I want to keep it all there.

23 MR. KELLERMAN: Yes, Brett Kellerman here

24 from Westinghouse.

25 I believe this lack of credit for

1 entrainment is a very major conservatism here.

2 MR. WARD: Yes, it is.

3 MR. KELLERMAN: If we were to credit it, I

4 don't believe the operators would ever have to restore

5 cold leg injection. It is similar to the AP plant.

6 CHAIRMAN BANERJEE: You, of course, use

7 COBRA/TRAC and you have entrainment, right?

8 MR. KELLERMAN: Correct, but we don't

9 credit it for boron removal.

10 CHAIRMAN BANERJEE: I see.

11 MR. WARD: So, if we look at this plot,

12 this plot of boric acid concentration, if I may -- can

13 you hear me? -- the boric acid concentration is a

14 function of time. This 29 percent precipitation limit

15 is based on a containment pressure of 14.7. I mean if

16 they went did a minimum LOCA containment pressure, you

17 could get something probably closer to 20 pounds,

18 which would jump this up to about 32 percent. But

19 they chose to use 14.7

20 Now there is additives in there, and that

21 would jump it up. As an example, in the Waterford

22 EPU, the additives push the boric acid concentration

23 up to 36 percent. So, if you throw the containment

24 and the additives in there, you are probably going to

25 put your limit somewhere up here.

1 But we are going to stick with 14.7. So,
2 now at 20 minutes, when you turn off the high-pressure
3 safety injection, we are now building up. We are not
4 flushing. We are not sweeping anything out. Let's
5 start it building up.
6 And the licensee calculation, four hours
7 and 50 minutes. My calculation, I get about the same
8 thing. It is an acceptable range of differences. My
9 drift velocity correlation, I have probably got it at
10 different velocity, slightly lower than theirs. So,
11 it is going to tend to trap more vendor in there and
12 make the mixing volume a little smaller.
13 But they are using COBRA/TRAC. That is a
14 two-fluid model. They are drag model is a little
15 different than mine. I used the bottom peak axial
16 power distribution. They used the top. So, that is
17 going to trap -- basically, there is going to be more
18 vapor residing in my calculation than theirs. So,
19 that is probably another reason for the slight
20 difference here. But I think I am consistent enough
21 to say, you know, we are in the same ball park.
22 MEMBER SIEBER: Right.
23 MR. WARD: Now what happened here is they
24 throw the half of the lower plenum in from time zero.
25 I don't do that because that is an incorrect

1 assumption.

2 There is cooler water in the bottom. Now

3 you are not going to mix down there until the density

4 of the boric acid in the water builds up, so that it

5 would then diffuse down there. So, that doesn't

6 happen until I get up to around 17 percent. Then, I

7 credit the half of lower plenum.

8 It is important to do that because I know

9 there were some EPUs where at 14.7 this spike can

10 shoot you up very fast. The higher power level, the

11 power-to-volume ratio is very important. I want to

12 make sure that that didn't happen.

13 So, the assumption that they threw it in

14 turns out to be okay. I don't like it, but in the

15 future that will change. But let's do it right. But

16 you want to make sure that nothing happens as a

17 surprise in the beginning. So, we are in the same

18 ball park.

19 CHAIRMAN BANERJEE: But that mixing time

20 will depend on volumes and all sorts of complicated

21 things, right? I can see that, if you just switch it

22 on, it zaps down, but in reality there is going to be

23 some behavior --

24 MR. WARD: Maybe so. It is oscillating

25 back and forth. I mean, hopefully, these tests, I

1 know the Owners' Group has got a pretty large effort
2 to come up with a model, a detailed model. They are
3 going to do some testing.
4 CHAIRMAN BANERJEE: There's some test on
5 this on a 3D system down in Dresden, Rossendorf. But
6 it depends now -- this is an FCK. But it also depends
7 on the jets and things, how it comes in.
8 MR. WARD: Okay.
9 CHAIRMAN BANERJEE: It is not independent,
10 you know, of how you introduce it, of course, as you
11 would expect.
12 MR. WARD: It seems like the more time we
13 spend on it, you know, we find out more stuff.
14 CHAIRMAN BANERJEE: The more complex it
15 becomes.
16 MR. WARD: I agree. That is why we are
17 having them --
18 CHAIRMAN BANERJEE: Yes.
19 MR. WARD: Look, this has to be a formal
20 plan. They are aggressively pursuing it. They are
21 going to come up with a model. They are going to do
22 some tests, and we are going to look at -- I think in
23 my letter of a couple years ago, three years ago,
24 there is a laundry list of things that they have to
25 look at that we need to know.

1 I mean these power uprates are pushing
2 these precip times, and we are not precipitating in 20
3 to 24 hours. So, when you switch at six or seven
4 hours, we have got five or six hours of margin. It
5 probably doesn't matter what you do. I mean there is
6 a lot of slack there. But the margin is decreasing.
7 And so, now we had better be a little bit
8 more careful and sharpen our pencils, and let's do it
9 right. Let's answer all the questions. And that is
10 what we are going to do.
11 CHAIRMAN BANERJEE: Yes.
12 DR. WALLIS: Are you going to do CFD as
13 well?
14 MR. WARD: You know --
15 CHAIRMAN BANERJEE: He has the same
16 opinion as --
17 MR. WARD: I have wanted to do that. We
18 have a proposal in. Money seems to be a little
19 difficult to come by, but I put that -- I want to do a
20 CFD calculation.
21 CHAIRMAN BANERJEE: It's tricky though
22 because you have got density differences.
23 MR. WARD: Right.
24 CHAIRMAN BANERJEE: You know, then the
25 scales of turbulence change it, interfaces, and it is

1 hard to do with CFD.

2 MR. WARD: Right. Like which model are we

3 going to use?

4 CHAIRMAN BANERJEE: Yes.

5 MR. WARD: But I think it needs to be

6 done. I mean I want to see a 3D calculation. What

7 happens when you add cold water? Do you get partial

8 localized precipitation? What is the mixing? How

9 much do you need to sweep this out?

10 CHAIRMAN BANERJEE: But without good

11 experiments, you know, the CFD is very tricky.

12 MR. WARD: Yes, I know. I know. But it

13 is a good step. It is a good step.

14 DR. WALLIS: You have got to do better

15 than assuming a half, right?

16 CHAIRMAN BANERJEE: I know.

17 MR. KELLERMAN: Right. I mean this is

18 Brett Kellerman from Westinghouse.

19 Yes, the half, it does on the surface

20 appear a bit arbitrary. It is based on test results

21 from a full-height facility. And, yes, you're right,

22 CFDs, you have got to be careful where you try to use

23 it in this problem.

24 MR. WARD: Yes. Well, it has obviously

25 got to be benchmarked, but I think it is something --

1 MR. KELLERMAN: Oh, yes, you need --

2 MR. WARD: -- we need to do. And I think

3 I am working with my Branch Chief here, and it will

4 happen. You know, I am sure it will happen.

5 CHAIRMAN BANERJEE: Well, you have got a

6 couple of good CFD people in NRC.

7 MR. WARD: We do.

8 CHAIRMAN BANERJEE: The only thing is I

9 don't trust the code.

10 MR. WARD: I agree. I mean I don't trust

11 any code, right? Even code I write, who trusts their

12 code? Make it prove itself every time.

13 And with CFD, I think you have hit the

14 nail on the head. There are a lot of variables. What

15 turbulence model do you use? I mean, good heavens.

16 But you have to start. If you want to go there, we

17 have got to start somewhere. I mean we are going to

18 learn something.

19 DR. WALLIS: Do you trust a seventh-scale

20 experiment?

21 CHAIRMAN BANERJEE: No.

22 MR. WARD: Well, scaling effects, there is

23 another issue.

24 CHAIRMAN BANERJEE: That is the problem.

25 The more you sit here, the more cynical you become.

1 MR. WARD: Yes. That's correct.

2 CHAIRMAN BANERJEE: Anyway, let's carry

3 on. Okay, it looks like you have got enough margin.

4 MR. WARD: Can you go back to the previous

5 slide? Yes.

6 DR. WALLIS: Why would you wait so long?

7 I mean, why would you not inject earlier? Why do you

8 wait for three hours? Is there some reason you don't

9 do it earlier?

10 MR. WARD: I think they have an AST

11 concern here. It is a radiological consideration.

12 The sprays in the containment are scrubbing the

13 radiation, and you want to make sure that you have

14 lowered it to very low levels.

15 MR. HALE: I'm Steve Hale. I am with

16 NextEra.

17 CHAIRMAN BANERJEE: Yes.

18 MR. HALE: If you remember when I was

19 describing the ECCS system alignment, the RHR pumps

20 are the only pumps that take suction on the sump. And

21 we have to align ourselves in a piggyback

22 configuration --

23 CHAIRMAN BANERJEE: Right.

24 MR. HALE: -- with both the containment

25 spray pumps and the high-pressure safety injection

1 pumps.

2 Now, as part of our AST, we are going to

3 containment spray on recirc. So, in order to do that,

4 we have to shut off the high-pressure pumps. And so,

5 you are looking at, well, if I run my containment

6 spray, I can reduce doses, but I need to be sure that

7 I don't run them too long because I have got to start

8 the high-pressure pumps at some point in order for

9 boron precipitation.

10 So, it is that piggyback operational

11 configuration that limits us from being able to just

12 have the high head pumps immediately once we go on

13 recirculation.

14 DR. WALLIS: If you needed containment

15 overpressure, you wouldn't want to run your

16 containment spray. You would have even more

17 interaction with --

18 MR. HALE: Right.

19 CHAIRMAN BANERJEE: They have very deep

20 sump pumps. So, they don't have to worry about that.

21 MR. WARD: It is NPSH.

22 CHAIRMAN BANERJEE: Yes. Right.

23 MR. HALE: Anyway, I hope that helps some.

24 MR. WARD: Yes.

25 CHAIRMAN BANERJEE: But why is it a

1 piggyback arrangement? Is it just a historical thing?
2 MR. HALE: On some of the older
3 Westinghouse plants, we are configured that way. I
4 can't speak to the other vendors. But I know Turkey
5 Point is similar. We have a piggyback arrangement.
6 The RHR pumps are lower head-type pumps and have
7 better NPSH characteristics. High-pressure pumps or
8 multi-stage pumps, they tend to have higher NPSH
9 requirements.
10 CHAIRMAN BANERJEE: There must have been a
11 reason.
12 MR. HALE: Yes. Yes, that was primarily
13 it.
14 CHAIRMAN BANERJEE: Yes.
15 MR. HALE: But, you know, things like in
16 the older times, like boron precipitation wasn't an
17 early issue in some of the earlier designs. And
18 things like piggyback operation came about. But most,
19 I would say, of the vintage `70 Westinghouse plants
20 follow that piggyback arrangement.
21 CHAIRMAN BANERJEE: Thank you. I think
22 that explains the logic of what is going on. Okay.
23 MR. WARD: So, what we have here is a
24 four-hour and 50-minute licensee-calculated
25 precipitation, which means you need to initiate high-

1 pressure safety injection before that happens to
2 control it.
3 The original timing recommendation by the
4 licensee for that was four hours and 20 minutes. And
5 since it takes 10 minutes to realign, that means you
6 would be controlling boric acid at about four and a
7 half hours.
8 So, when I looked at that, I said 20
9 minutes, there is no margin there. That is certainly
10 not typical of all the other plants out there; they
11 have at least an hour.
12 And so, the licensee went back and looked
13 at it and came up with three hours and 20 minutes,
14 which is more than an hour, at least an hour of
15 margin. That is more in tune with what we would like
16 to see. I mean there needs to be margin there. What
17 if the operator makes an error? I mean, heaven forbid
18 if he closes or opens the wrong valve. If you've only
19 got 20 minutes -- you know, an hour, an hour and 20
20 minutes, that is certainly more comfortable. So, we
21 felt that that was acceptable. Considering there are
22 other conservatisms in the analysis, I think the
23 margin is probably a little bit more than that, but at
24 least it is at least an hour.
25 The other thing, the other concern I had

1 was they had these high-concentrate boric acid tanks.
2 Now if they discharge and they are not turned off,
3 that precipitation time could be less than two hours.
4 So, it is not highly likely that that will happen,
5 but the fact that it could happen says you have got to
6 deal with it.
7 And so, they have put instructions in
8 their EOPs if they are discharging, to turn those
9 things off. And within 20 minutes, if it is turned
10 off, certainly there won't be any effect.
11 But that is consistent with what we have
12 done with CE plants when we had the high-concentrate
13 boric acid tanks. There was an immediate action in
14 those EOPs for CE plans to terminate the injection of
15 those high-concentrate tanks. They are 20,000 ppm, 12
16 weight percent. Those instructions were to turn those
17 off in no later than 15 minutes post-LOCAs, so that
18 you don't want to deal with large amounts of boron
19 being dumped into the system. So, they addressed that
20 through their EOPs.
21 Now the operator action time of 10 minutes
22 to turn on and realign the high-pressure safety
23 injection, they confirm that through exercises with
24 the operators on the simulator. And as a matter of
25 fact, they have made it a part of their testing and

1 their operating training and qualification program.
2 That is something the operators will be trained on
3 every year because it is important that this is
4 emphasized. This is an emphasis in the training
5 program as far as LOCA and responding to a LOCA to
6 control boric acid.
7 So, anyway, the staff, our review of this,
8 our calculations of their long-term cooling analysis
9 and the margin that they have put in there, the
10 addressing of termination of boric acid storage tanks,
11 the staff feels that there is now sufficient margin
12 that this will get acceptable. Long-term cooling
13 performance is demonstrated, which meets 10 CFR 50.46.
14 As such, the staff finds this --
15 CHAIRMAN BANERJEE: You know, I didn't ask
16 you a facetious question really when I said, can you
17 put a resistance in the core due to debris?
18 MR. WARD: Due to debris? Well, it is an
19 area blockage, right?
20 CHAIRMAN BANERJEE: Well, what it does is,
21 of course, it does that, and it will change the
22 flowrates and things. And I don't know what effect it
23 will have, but it is not associated with this?
24 MR. WARD: It is a K factor.
25 CHAIRMAN BANERJEE: Hum? It is a K

1 factor.

2 MR. WARD: It is a K factor.

3 CHAIRMAN BANERJEE: Well, it is a K

4 factor, but remember K varies with velocity here

5 because it is not going to be --

6 MR. WARD: Right.

7 CHAIRMAN BANERJEE: -- going as a

8 constant.

9 MR. WARD: The flow varies the K --

10 CHAIRMAN BANERJEE: Yes. So, it will vary

11 the K factor, and it will build up over time. It

12 doesn't happen immediately.

13 It is not related to this review, but

14 perhaps the next step, which is eventually the in-

15 vessel effect, has to get resolved --

16 MR. WARD: Right.

17 CHAIRMAN BANERJEE: -- when more data

18 comes on that and stuff like that.

19 MR. WARD: Yes, I agree, and that is

20 something that would have to be factored in.

21 CHAIRMAN BANERJEE: But, no, boric acid is

22 one of the limiting --

23 MR. WARD: Right. No, I agree. I agree.

24 I agree with you. Yes, that could be an important

25 factor.

1 CHAIRMAN BANERJEE: Because what
2 Westinghouse will undoubtedly do is run COBRA/TRAC, of
3 course.
4 MR. WARD: Yes, yes.
5 CHAIRMAN BANERJEE: Right? Or somebody
6 else will. And we would want some independent
7 confirmation, I'm sure.
8 MR. WARD: Sure. I mean we have TRACE,
9 RELAP5.
10 CHAIRMAN BANERJEE: Yes, but there is
11 nothing like doing it by hand.
12 MR. WARD: Sure, and then my code.
13 CHAIRMAN BANERJEE: Yes.
14 MR. WARD: And I have full control over
15 mine. I like that.
16 CHAIRMAN BANERJEE: This is not that
17 complex calculation in that sense. Right?
18 MR. WARD: Right. I agree.
19 CHAIRMAN BANERJEE: But, remember, K will
20 vary with flow.
21 MR. WARD: Flow, right.
22 CHAIRMAN BANERJEE: So, it is more
23 laminar.
24 MR. WARD: It is not turbulent flow. So,
25 it is very sensitive to that.

1 CHAIRMAN BANERJEE: Yes, it is sensitive
2 to that.
3 MR. WARD: Yes, I can see that.
4 CHAIRMAN BANERJEE: Yes.
5 MEMBER SHACK: And K also varies with area
6 on the bottom of the core, as it tries to equalize the
7 resistance.
8 CHAIRMAN BANERJEE: Right. It will
9 also --
10 MR. WARD: AW over A squared, right?
11 CHAIRMAN BANERJEE: Yes, it will sort of
12 jam some part and then more will come. And that is
13 what the experiments show, of course.
14 MR. WARD: Yes.
15 CHAIRMAN BANERJEE: We used to think that,
16 you know, that it would actually have regions of
17 blockage and not. But the flow just redistributes and
18 everything is blocked. So, ultimately, that is what
19 happens.
20 All right.
21 MR. WARD: Exactly.
22 DR. WALLIS: Well, we don't know that is
23 what happens until we test a full-scale core.
24 (Laughter.)
25 CHAIRMAN BANERJEE: Well, yes, that's

1 right.

2 MEMBER SHACK: We would see a P

3 calculation.

4 CHAIRMAN BANERJEE: Okay.

5 DR. WALLIS: But always surprises.

6 CHAIRMAN BANERJEE: That's a digression.

7 Anyway, let's move on. Thank you.

8 You set up conclusions?

9 MR. WARD: Yes, I did. Well, our time

10 here to speak was cut down. So, I tried to cut down

11 the number of slides as best I could.

12 But, just to summarize, to end this, we

13 did some RELAP5 calculations to confirm the non-

14 limiting of a small-break LOCA. The limiting break

15 was a 3-inch using RELAP5, and I got a PCT of 1300

16 degrees compared to their 1103.

17 And because of the high capacity of that

18 high-pressure safety injection pump, there is very

19 little core -- it can put a lot of flow in there.

20 CHAIRMAN BANERJEE: So, you did deal with

21 my refluxing question there?

22 MR. WARD: Yes.

23 CHAIRMAN BANERJEE: Right?

24 MR. WARD: Yes. We did. You get it in

25 about the first 400 seconds. The primary pressure for

1 a 3-inch break is around 1100 pounds before you get
2 the steam out the break and depressurize. But it is a
3 function of the smaller the break, the longer you
4 would be on that pressure plateau because that plateau
5 is terminated by when you would drain the loops --
6 CHAIRMAN BANERJEE: Do you have the
7 velocities of the steam and the water in that
8 refluxing phase? You can get all in calculations,
9 right?
10 MR. WARD: Yes, it is in the calculations.
11 I can get that.
12 CHAIRMAN BANERJEE: I just want to check
13 it against --
14 MR. WARD: I can get that.
15 CHAIRMAN BANERJEE: -- some recent elbow
16 flooding experiments.
17 MR. WARD: So, you want to look at
18 velocities in the steam generator tubes or in the hot
19 leg?
20 CHAIRMAN BANERJEE: And also in the hot
21 leg.
22 MR. WARD: The hot leg? And you want to
23 look at possible entrainment effects?
24 CHAIRMAN BANERJEE: Yes, I just want to
25 take a look at that.

1 MR. WARD: The liquid flowing on the
2 bottom occupies a very small flow area.
3 CHAIRMAN BANERJEE: Yes, what has been
4 found, of course -- I don't know if you know it -- is
5 that as you operate these things, you get to a point
6 where you can get flooding. So, you can't drain the
7 liquid back.
8 MR. WARD: Yes.
9 CHAIRMAN BANERJEE: So, it just locks up
10 and accumulates in the tube. I think if you remember
11 semi-scale, there was an --
12 MR. WARD: Yes, it depresses the level of
13 the core when that happens.
14 CHAIRMAN BANERJEE: Yes. That's right.
15 MR. WARD: I remember that.
16 CHAIRMAN BANERJEE: Yes.
17 MR. WARD: Yes.
18 CHAIRMAN BANERJEE: So, until the loop
19 seal is clear and then --
20 MR. WARD: That's right. Correct.
21 CHAIRMAN BANERJEE: And that is probably
22 much less of a concern here than with a reactor where
23 you are using secondary site cooldown to control the
24 pressure.
25 MR. WARD: Right. That's right.

1 CHAIRMAN BANERJEE: You know what I'm
2 referring to.
3 MR. WARD: Right. This is in the first
4 hour, so it is there.
5 CHAIRMAN BANERJEE: Yes.
6 MR. WARD: But, remember, the semi-scale
7 is not a good representation of a power plant. The
8 tube area is very small.
9 CHAIRMAN BANERJEE: Yes.
10 MR. WARD: So, you are going to see holdup
11 in there that you wouldn't see in a full-scale plant.
12 CHAIRMAN BANERJEE: Yes.
13 MR. WARD: So, just keep that in mind.
14 CHAIRMAN BANERJEE: But, assuming that
15 your RELAP5 calculations do take flooding in the tube
16 into account --
17 MR. WARD: They do. They do.
18 CHAIRMAN BANERJEE: But whether they take
19 it in the hot leg was the question.
20 MR. WARD: You can put that in there, too.
21 You can do that.
22 CHAIRMAN BANERJEE: But if I have those
23 numbers, I can work it out by hand.
24 MR. WARD: Okay. All right. I will get
25 them to Zeyna.

1 CHAIRMAN BANERJEE: Yes. All right.

2 MR. WARD: I will look that up for you.

3 Not a problem.

4 CHAIRMAN BANERJEE: Okay.

5 MEMBER SIEBER: Okay. Thank you.

6 MR. WARD: Well, I guess based on the

7 review, their long-term cooling methods and the

8 margin, the changes that they made to terminate the

9 boric acid makeup tank and to increase the margin, the

10 timing between when they would initiate realignment of

11 the high-pressure safety injection and control boric

12 acid, you know, we find that, the staff finds these

13 changes acceptable.

14 CHAIRMAN BANERJEE: Okay. Thank you.

15 And now, Ben, I think it is you, right?

16 MR. PARKS: I will talk about the steam

17 generator tube rupture.

18 Before I get into the tube rupture event,

19 I would like to provide a little bit of context. My

20 focus is on the thermal hydraulic analyses that the

21 licensee performed. So, when I make some statements,

22 I am generally referring to those and not necessarily

23 the radiological consequences analysis, which is their

24 licensing basis analysis.

25 The thermal hydraulic analyses are beyond

1 the Point Beach design basis. I think they covered
2 that this morning or early afternoon.
3 The challenging aspect of this review is
4 there are no explicit acceptance criteria beyond what
5 is covered in the NRC-approved --
6 CHAIRMAN BANERJEE: Before you go on, Ben,
7 how long are you going to take?
8 MR. PARKS: I don't anticipate taking more
9 than 10 minutes.
10 CHAIRMAN BANERJEE: Great. Okay. Then we
11 will do that.
12 MR. PARKS: Okay.
13 CHAIRMAN BANERJEE: And, then, we will
14 take a break.
15 Go ahead.
16 MR. PARKS: As I said, there are no
17 explicit regulatory acceptance criteria. We would
18 look at WCAP-10698 for what the framework is for an
19 acceptable margin-to-overfill analysis. And that is
20 about the best idea that we can get in terms of
21 generic guidance outside the radiological
22 consequences.
23 And so, basically, the objective of the
24 tube rupture review is to determine what a reasonable
25 assessment of the radiological consequences are.

1 In the next slide, I will explain what the
2 licensee did. It provided three calculations. The
3 licensing basis analysis is what they refer to as the
4 hand calculation. It makes some pretty significant
5 conservative assumptions for the purpose of sort of
6 maximizing the radiological release to the atmosphere.
7 One of those is a constant conservative
8 post-trip break flow flashing fraction, and that helps
9 to get a lot, a high fraction of radionuclides into
10 the atmosphere. It also assumes that there is no
11 operator intervention for 30 minutes. So, this event
12 is proceeding unmitigated in the analysis.
13 It does assume that the break flow
14 terminates in 30 minutes, and it also assumes that the
15 steam generator does not overfill with water. That
16 would, of course, cause some problems isolating the
17 ruptured generator from the atmosphere through the
18 pressure relief valves. It would also change the
19 radionuclide inventory that is released.
20 Since those assumptions may be
21 questionable, the licensee produced two additional
22 calculations to show us that the hand calculation is
23 conservative. One of those is an extended blowdown
24 mass release calculation which is designed to back off
25 the conservatism of that constant high flashing

1 fraction and show that, if you back off of that, you
2 still have some time beyond 30 minutes to isolate the
3 ruptured steam generator. And so, I think that
4 analysis showed that the ruptured steam generator
5 didn't isolate for something like 40 to 50 minutes,
6 and it showed that the predicted radiological
7 consequences were bounding in the hand calculation by
8 a factor of approximately two.
9 The licensee also provided a margin-to-
10 overfill analysis which backed off of the
11 conservatisms set forth in the approved analytic
12 methodology and used some nominal state point
13 assumptions. They presented that to demonstrate that
14 they had margin to overfill.
15 We didn't exactly accept that calculation,
16 and we asked them to repeat it. They went to the more
17 bounding assumptions that are set forth in the
18 approved WCAP, but they did not include that limiting
19 single failure.
20 CHAIRMAN BANERJEE: So, the use of the
21 LOFTRAN -- this is LOFTRAN, right?
22 MR. PARKS: It is a modified version of
23 LOFTRAN.
24 CHAIRMAN BANERJEE: Some version of it?
25 MR. PARKS: Yes.

1 CHAIRMAN BANERJEE: And that is being
2 demonstrated to work on this type of overfill problem
3 reasonably?
4 MR. PARKS: The staff generically accepted
5 it when we approved the WCAP, I think, in 1987 or
6 1988. So, that included some validation studies, and
7 LOFTRAN itself has been validated against actual plant
8 data.
9 CHAIRMAN BANERJEE: Okay. So, the only
10 issue was not with the code, but the methodology was
11 not including the single failure? Or were there other
12 things?
13 MR. PARKS: No, I'm sorry. The issue, I
14 think the main issue was they used a nominal value of
15 initial mass, initial liquid mass, in the steam
16 generator. And so, that effectively produces a direct
17 bias on the result. So, if you go a little bit
18 higher, you have a little bit less margin to overfill.
19 So, if you are very close to filling up the steam
20 generator, you add that water and you are full.
21 CHAIRMAN BANERJEE: Yes.
22 MR. PARKS: So, it was some issues with
23 the application of the methodology and that single-
24 failure assumption. Because, for instance --
25 CHAIRMAN BANERJEE: They are two separate

1 things. The methodology and the single-failure
2 assumption, right?
3 MR. PARKS: That is correct.
4 CHAIRMAN BANERJEE: Yes, all right.
5 MR. PARKS: Because the methodology says
6 that taking the single failure is a conservative
7 assumption. So, yes, the two separate items.
8 In the referenced plant analysis, a single
9 failure is tolerable because you have three steam
10 generators. So, if you lose your ability to blow down
11 one and cool the RCS, you have a spare. Well, at
12 Point Beach you don't have that. So, that is a
13 challenging failure for that or a challenging
14 assumption.
15 CHAIRMAN BANERJEE: But Ginna had the same
16 problem in Ginna, right?
17 MEMBER SIEBER: Right.
18 MR. PARKS: Ginna has a steam generator
19 with narrower tubes. So, they have a little bit more
20 design margin in the way the plant is built to
21 accommodate that single failure because, actually,
22 what they do is they assume that they can't remotely
23 operate the valve; it needs a manual action. And so,
24 they just delay that step in the analysis. In the
25 analysis, that is an assumed operator intervention.

1 CHAIRMAN BANERJEE: Okay.

2 MR. PARKS: Regarding the atmospheric dump
3 valve assumption, we reviewed their defense-in-depth
4 mechanisms to make sure that excluding a single
5 failure was reasonable. Basically, what they wound up
6 doing was assuring us that they would likely have
7 instrument air. They need to open the ADV about 17
8 minutes after the event inception. They demonstrated
9 a number of different ways that, if they were
10 challenged regarding their instrument air, they would
11 be able to restore it and have the ability to open or
12 operate the valve.

13 DR. WALLIS: Is this the air that comes
14 from a shared system between the two units? Is that
15 what --

16 MR. PARKS: That is correct. The
17 instrument air is a shared system. It is not
18 unitized.

19 DR. WALLIS: Right. When they explained
20 this, it sounded reasonable. What you have in the SER
21 sounds more questionable. You talk about taking
22 credit from items from an unaffected unit, and that
23 sort of says, well, what items are you taking credit
24 for and is it reasonable?

25 CHAIRMAN BANERJEE: Right, instrument air,

1 right?

2 DR. WALLIS: So, the way it is written, it

3 raises a flag. But the way it is explained, it sounds

4 much more reasonable.

5 MR. PARKS: That is correct. We were

6 drafting the SER as we were completing the review.

7 When we started, we had an understanding that we have

8 two separate units, two separate instrument air

9 systems and crossties. We, through the review

10 process, came to an understanding that is actually a

11 shared single system.

12 So, in terms of what we reviewed, we

13 actually went out. We did a site visit. We worked

14 with our regional colleagues in the Operator Licensing

15 Branch to make sure that we are looking at the right

16 actions.

17 They showed us their procedures to restore

18 instrument air. Actually, when we observed it in the

19 simulator, I think half of the NCR crew observing

20 missed their actions because it was so quick.

21 Somebody asked if there was load available on one of

22 the diesel generators. Somebody else went back and

23 flipped the switch, and that was the action. It was

24 pretty quick.

25 So, in terms of making sure that there's

1 instrument air there to operate the valve, we think
2 that that is a reasonable assumption to make in the
3 analysis. The penalty for not having that is about
4 three to four additional minutes to get the valve open
5 for a local action. And we saw that actually, too.
6 We climbed up to the top of the reactor building and
7 watched them move to do that. So, we saw it all.
8 DR. WALLIS: Actually, somebody going
9 there and opening it?
10 MR. PARKS: That is correct. Fortunately,
11 the steamlines are separated. So, if there is
12 anything happening in the ruptured generator, they
13 have got a little bit of distance.
14 Basically, that was our review for the
15 tube rupture. We believe that the hand calculation is
16 conservative. These two additional analyses provided
17 a valid validation, an acceptable validation of the
18 hand calculation.
19 And the other important consideration is,
20 because the steam generator level is inversely
21 proportional to the power level, they have less
22 initial mass in the steam generator at EPU conditions.
23 And from a margin-to-overfill perspective, it means
24 the EPU doesn't exacerbate the consequences. But we
25 also assured that it is safe at the current license

1 thermal power level.

2 That is it for the tube rupture.

3 CHAIRMAN BANERJEE: Right.

4 MR. PARKS: And we have a conclusion set.

5 CHAIRMAN BANERJEE: Now is there anything

6 more that you want to say before we take a break?

7 MR. PARKS: I am just going to run through

8 my conclusions slide. I heard a couple of questions

9 this morning, and I scribbled some answers, but those

10 are pretty quick, if you don't mind.

11 DR. WALLIS: Do we have time to ask

12 questions before we take a break?

13 CHAIRMAN BANERJEE: If you absolutely

14 wish, yes.

15 (Laughter.)

16 DR. WALLIS: Well, now would be the best

17 time to do it.

18 CHAIRMAN BANERJEE: No, there's time.

19 MR. PARKS: Okay. Again, we followed

20 RS-001. We performed an independent assessment of the

21 EPU. We did some engineering evaluations and

22 independent calculations. We performed a site visit

23 and a desk audit of their calculations, and we found

24 the EPU acceptable with respect to the safety

25 analysis.

1 Again, I wrote down a couple of notes. I
2 would like to clarify regarding the assessment of
3 penalties for DNBR and the safety analysis limit. The
4 safety analysis limit is established by the licensee
5 or by Westinghouse. It doesn't reflect the regulatory
6 acceptance criteria that is in SRP Chapter 4, which is
7 95/95 probability that I think 99.9 percent of the
8 rods in the core would not experience a departure from
9 nucleate boiling.
10 So, I think the safety analysis, or I'm
11 sorry, the correlation limit is what provides that
12 assurance. And the safety analysis limit has a margin
13 to that, and that is an administrative margin.
14 And so, for us, in terms of looking at
15 that, that didn't give us too much heartburn. We did
16 ask about it, but it wasn't a big problem for us.
17 I discussed for a paragraph in my safety
18 evaluation on the use of WRB-1 and W3. They will use
19 W3 when the WRB-1 correlation limits are exceeded or
20 not met. So, they are using W3 when they are not
21 supposed to be using WRB-1. And that is, I think, the
22 biggest difference why they would pick one over the
23 other. For most transients, they are using WRB-1.
24 I think Steve Hale answered the question
25 on bounding versus nominal safety analysis inputs. In

1 most cases, they were bounding, unless they were
2 performed using the revised thermal design procedure.
3 And in that case, the uncertainties are treated
4 statistically and added at the end. So, there is an
5 explicit accounting for uncertainties in all the
6 safety analyses except the defense-in-depth
7 sensitivity studies, like the margin-to-overfill
8 calculation, which at the end of the day still used
9 validating assumptions.
10 When I reviewed Point Beach's request to
11 implement ASTRUM, I asked them specifically what the
12 EPU effect would be on the analysis results. I asked
13 them to do that at the median cases for the ASTRUM
14 deck because I was a little concerned that if they
15 looked at the upper tolerance limit cases, the
16 parametric distributions going into that would be so
17 scattered that I didn't know that the results would
18 mean too much.
19 So, I thought, if they looked at the
20 middle of the road and assumed, you know, the current
21 licensed thermal power and the EPU power level, I
22 would get a better idea. The impact was about 75 to
23 100 degrees. The EPU had a higher PCT.
24 DR. WALLIS: And how low is the mean
25 compared with the 95/95?

1 MR. PARKS: About 600 degrees, around
2 1300.
3 DR. WALLIS: A lot less. A lot less, yes.
4 MEMBER SHACK: That is the median or the
5 mean?
6 MR. PARKS: I asked for median.
7 DR. WALLIS: Well, it is a best estimate
8 one way or the other. It is way below the peak.
9 MR. PARKS: Correct. And I had heard that
10 question, and that was the last point that I was going
11 to bring up.
12 And with that, I am finished. Dr. Wallis,
13 I understand you have some questions.
14 DR. WALLIS: Well, I have two questions
15 from the SER. Both concern water hammer.
16 There were major modifications to the AFW
17 pumps. Now the staff writes, "The staff considered
18 the likelihood of water hammer." That is very
19 interesting. So, I want to see what did they
20 consider, how did they conclude. There is nothing.
21 It just says they considered the likelihood of water
22 hammer. It never says they concluded it couldn't
23 happen or it would happen or anything.
24 MR. PARKS: Could you provide the section
25 number.

1 DR. WALLIS: It's open-ended. It is
2 Section 2.5.4.
3 MR. PARKS: That was outside the reactor
4 system's review area.
5 DR. WALLIS: It is open-ended, you know.
6 They considered it, but they don't tell you what they
7 did.
8 (Laughter.)
9 And, then, the fan coolers --
10 MR. GARDOCKI: This is Stan Gardocki. I
11 work in the Balance of Plant Branch.
12 DR. WALLIS: Yes.
13 MR. GARDOCKI: We evaluated whether there
14 was any changes in the system that would cause us to
15 really evaluate a new water hammer effect. And we
16 crosschecked it with EMCB, and they said, no, there
17 was no changes that would affect the system to induce
18 any water hammer.
19 DR. WALLIS: Maybe the SER could say that,
20 rather than just leaving it open-ended.
21 MR. GARDOCKI: Yes, sir.
22 DR. WALLIS: And, then, in the service
23 water, the contaminant is hotter and there is this
24 problem or this question about containment fan
25 coolers, they drain and they refill and there can be

1 water hammer.

2 And apparently, the licensee had to assume

3 fouling in order to make things come out right;

4 whereas, the no fouling conservative assumption wasn't

5 good enough.

6 So, I just wondered how they assumed a

7 reasonable amount of fouling, which was sort of

8 acceptable, because the fouling is difficult to

9 predict, isn't it, in a situation?

10 MR. PARKS: I believe that was also

11 outside the reactor system area.

12 DR. WALLIS: This is all in the SER, and

13 it is in Section 2.6.5.

14 CHAIRMAN BANERJEE: Who wants to answer

15 that from the staff side?

16 DR. WALLIS: It says, "The NRC staff was

17 not satisfied." Well, so how did it get concluded?

18 CHAIRMAN BANERJEE: They are saying that

19 they --

20 DR. WALLIS: They didn't do it.

21 CHAIRMAN BANERJEE: -- didn't do it.

22 DR. WALLIS: But somebody did it.

23 CHAIRMAN BANERJEE: Somebody did it.

24 (Laughter.)

25 MR. PARKS: We were in charge of Section

2.8.

DR. WALLIS: Okay, but somebody did it.

MR. ULSES: Dr. Wallis, this is Tony Ulses from the staff.

Would you provide the --

CHAIRMAN BANERJEE: Section number.

MR. ULSES: -- section number.

DR. WALLIS: I think it says the containment fan coolers, Section 2.6.5, but they are actually being discussed in 2.5-something as well, 2.5.4 I think. So, it is somewhere in there.

MR. ULSES: Yes, we will get back with you with an answer on that question.

DR. WALLIS: It just seemed another one of these open-ended things. And I think Point Beach is going to talk about these containment fan coolers as well.

CHAIRMAN BANERJEE: It is in the SER. So, I think the staff will address it.

MR. HANLEY: I think the reference you are making to the water hammer was the event where, just like you said, they would heat up the fan coolers. The tubing and all that would void due to the temperature in the containment.

The original analysis assumed there was no

1 fouling. So, the heat transfer was at a maximum. It
2 could be. And we are saying, because of the
3 temperature difference based on the accident, it went
4 up a few degrees, that with a reasonable assumption,
5 then you are still well below the 10001 fouling factor
6 that you would expect from a design. The analysis
7 would still be good.
8 It is a fact that it is a very small
9 number. Like it is like .000 -- two times 10 to the
10 minus 5.
11 DR. WALLIS: Apparently, it is big enough
12 to make a difference from no fouling, which makes it
13 okay.
14 MR. HANLEY: Yes, it is just the fact that
15 zero fouling is the worst you can get, the most heat
16 transfer you can get with the higher temperature. In
17 other words, we are saying, if you had some fouling,
18 then the heat transfer would be similar.
19 DR. WALLIS: But they needed to do this,
20 did they?
21 MR. HANLEY: Yes, because the temperature
22 went up in the containment.
23 DR. WALLIS: So, that very, very small
24 amount of fouling makes a big difference, a
25 significant difference to the potential for water

1 hammer.

2 MR. HANLEY: Well, no, it doesn't make a

3 significant difference. What you are saying is that,

4 if you had some fouling, a very small amount, you

5 would still see the same effect.

6 CHAIRMAN BANERJEE: Well, I think you can

7 address it, but he is talking about the SER.

8 DR. WALLIS: Yes, the SER needs to be, I

9 think, more explicit because it also says, "The NRC

10 staff was not satisfied." So, it needs to be

11 resolved.

12 CHAIRMAN BANERJEE: Yes. Tony said that

13 he is going to do this.

14 DR. WALLIS: That's right.

15 CHAIRMAN BANERJEE: So, let's defer that

16 for later. Do you have any other questions?

17 DR. WALLIS: So, it was necessary to

18 assume this little bit of fouling?

19 MR. HANLEY: Yes.

20 DR. WALLIS: So, if they were very good

21 and manufactured these things without any fouling and

22 were very, very clean, they would be in trouble?

23 MR. HANLEY: Well, I don't know if you

24 would be in trouble, but, yes, you wouldn't expect

25 there would be zero fouling; that's for sure.

1 CHAIRMAN BANERJEE: All right? Thank you.
2 Any others? Bill?
3 So, this will actually, if I understand
4 it, conclude the discussion of safety analysis.
5 We will take a break and come back. Then,
6 the staff will come back with the materials and
7 chemical engineering part.
8 So, I would like to thank you, all of you,
9 the safety analysis crew, for your presentations. I
10 think you have clarified a lot of points. So, thanks
11 very much.
12 We will take a break now for, let's take
13 it for 15 minutes, 20 to 4:00. We are almost back on
14 schedule. So, that's good.
15 (Whereupon, the foregoing matter went off
16 the record at 3:24 p.m. and went back on the record at
17 3:42 p.m.)
18 CHAIRMAN BANERJEE: So, we are back on the
19 record.
20 And I will go back to Terry.
21 MR. BELTZ: Yes, we will continue with the
22 afternoon session.
23 CHAIRMAN BANERJEE: Right.
24 MR. BELTZ: The discussion, the
25 presentation on materials and chemical engineering

1 from Andy Johnson.

2 MR. JOHNSON: Thank you, Terry.

3 I am Andrew Johnson from the Division of

4 Component Integrity, despite what my name tag here

5 says.

6 Go ahead.

7 CHAIRMAN BANERJEE: What does your name

8 tag, what is EMCB?

9 MR. JOHNSON: EMCB? That is the

10 predecessor of DCI. It was in existence before I came

11 to the NRC.

12 CHAIRMAN BANERJEE: All right.

13 MR. JOHNSON: I reviewed five areas that

14 we are going to go through today. The first was the

15 protective coating systems.

16 So, Point Beach, you know, their license

17 predates Reg Guide 1.54 and ANSI 101.4, which are what

18 they have committed to in their current licensing

19 basis to maintain.

20 Their coatings were accepted in the FSAR

21 based on some testing that was done after the fact.

22 MEMBER SHACK: Are these just conventional

23 zinc primers that we would sort of expect?

24 MR. JOHNSON: Correct, Amercoat and

25 Dimetcote.

1 CHAIRMAN BANERJEE: No epoxies?

2 MR. JOHNSON: I don't recall specifically.
3 I remember Amercoat and Dimetcote. I don't remember
4 if there were any epoxies, right off the top of my
5 head.

6 MEMBER SHACK: When they have to repair a
7 coating, do they do that now consistent with 1.54?

8 MR. JOHNSON: Correct. They are
9 consistent with Service Level 1 coatings. And they do
10 repairs. There is an exception. They maintain a log
11 for small repairs that are under 1 square foot.

12 DR. WALLIS: This is a concrete
13 containment with a lining?

14 MR. JOHNSON: Yes.

15 DR. WALLIS: Okay.

16 MR. JOHNSON: So, I compared their post-
17 EPU temperatures, peak temperature, peak pressure, pH,
18 and radiation dose under EPU accident conditions.
19 They still remained bounded by the original test
20 acceptance conditions.

21 And I would note, based on some
22 discussions that you all had earlier today, I did not
23 consider Generic Letter 2004-02, GSI-191, and the
24 resolution of that within the scope of my review. We
25 have other people in my Branch that are specifically

1 spearheading that.

2 We discussed this a year ago and said it

3 was just, what they proposed in their application was

4 that they were going to keep it separate, and other

5 people in my Branch concurred. So, that is what we

6 did.

7 Next slide.

8 The next area was flow accelerated

9 corrosion. Just about everybody else that I know of

10 in industry, they use EPRI Report NSAC-202L, the

11 recommendations for flow accelerated corrosion

12 program. Along with that, they use the CHECWORKS

13 software modeling.

14 They have already run the updated EPU

15 conditions in the CHECWORKS model. They came out with

16 both increases and decreases predicted in the

17 corrosion rates.

18 MEMBER SHACK: Is this primarily just due

19 to temperature changes? Some of them go over the peak

20 and under the peak? Is that what is driving it?

21 MR. JOHNSON: As far as -- well, I would

22 think a lot of it --

23 MEMBER SHACK: I mean velocities would,

24 presumably, always increase.

25 MR. JOHNSON: Correct.

1 MEMBER SHACK: But I am trying to figure,
2 decreases would be temperature changes?
3 MR. JOHNSON: Based on pressure.
4 MEMBER SHACK: Pressure.
5 MR. JOHNSON: You have some pressure
6 decreases.
7 CHAIRMAN BANERJEE: Well, the core outlet
8 temperature is high, but the core inlet temperature is
9 lower, correct, on this?
10 MR. JOHNSON: Correct.
11 CHAIRMAN BANERJEE: The delta T is larger.
12 MR. JOHNSON: They stated that they would
13 verify any predicted decreases with the model with
14 direct examination prior to that being implemented in
15 the model long-term permanently, and that increases
16 would be put into the model right away.
17 And, then, the scope of the FAC program
18 did not change. Nothing new was added to the scope of
19 the FAC program.
20 I went back and looked at the license
21 removal that they underwent in 2005 and reviewed those
22 RAIs and saw that they had made a fair amount of
23 changes back then. So, that made sense to me, that
24 they wouldn't have had to do any recent changes. They
25 did uprev from Rev. 2 to Rev. 3 of the EPRI guidelines

1 between the license renewal and the EPU application.
2 So, they are still bounded.
3 Next slide.
4 Steam generator tube integrity is the next
5 section. They used NEI 97-06, Steam Generator Program
6 Guidelines, like you would expect, run out of their
7 technical specifications, and reviewed their current
8 tech specs, along with any current alternate repair
9 criteria.
10 Unit 1 does have an interim alternate
11 repair criteria for the H-STAR criterion.
12 MEMBER SHACK: Oh, it's an H-STAR
13 criterion?
14 MR. JOHNSON: It is an H-STAR criterion,
15 that's right.
16 And Unit 1 has alloy 600 thermally-treated
17 tubes. As they said earlier, Unit 2 is 690 thermally-
18 treated.
19 The steam generator design parameters
20 still bound EPU uprate conditions.
21 Next slide.
22 The steam generator blowdown system,
23 regulated from looking at RSO 1, directs you to some
24 generic design criteria in Appendix A of 10 CFR 50.
25 Of course, they predate the Appendix A general design

criteria. They have equivalent older GDCs. We looked at those, saw that they were comparable.

Again, the steam generator blowdown system, your pressure, your temperature is very similar. No expected change in blowdown flow rate at EPU conditions. And so, the original steam generator design parameters are still bounding for EPU.

And, then, the steam generator blowdown components specifically are still monitored by the FAC program.

Next slide.

And lastly, the chemical and volume control system. Again, they have specific GDCs that predate the current Appendix A GDC. I looked at those.

They have a prediction of a slight increase in boration requirement and potential for increased crude buildup, but both of these increases are bounded by the current capabilities of the CVCS system. And so, they are still bounded.

And as a note, CVCS was not used as high-pressure injection, as it is on some plants, but not for Point Beach.

And so, in summary, those are the five areas that I looked at. And I found them to be

1 acceptable at EPU conditions.

2 CHAIRMAN BANERJEE: Okay.

3 MEMBER SIEBER: Did Point Beach originally

4 have a BIT tank?

5 MR. JOHNSON: I'm sorry, a what?

6 MEMBER SIEBER: Did they have a boron

7 injection tank originally?

8 MR. JOHNSON: I don't know.

9 MR. HANNEMAN: This is Harv Hanneman from

10 NextEra Point Beach.

11 We had what we call boric acid storage

12 tanks. They were on the suction of the SI pumps, not

13 on the discharge, which your BIT tanks are.

14 MEMBER SIEBER: Okay.

15 MR. HANNEMAN: But they originally were

16 used for high-concentration boric acid injection with

17 safety injection. We removed those about 10 years ago

18 from the safety injection flow system.

19 MEMBER SIEBER: Flow path, yes.

20 MR. HANNEMAN: We still use them for CVCS

21 charging for boration --

22 MEMBER SIEBER: Okay.

23 MR. HANNEMAN: -- although the boric acid

24 concentrations have been reduced considerably --

25 MEMBER SIEBER: Right.

1 MR. HANNEMAN: -- from when we used them
2 for safety injection.
3 MEMBER SIEBER: Okay. Thank you. Thanks.
4 CHAIRMAN BANERJEE: Okay.
5 MEMBER SIEBER: Thank you.
6 CHAIRMAN BANERJEE: Bill, did you have any
7 other questions in the materials?
8 MEMBER SHACK: Well, there are some
9 questions yet about the welds on, I guess, the Unit 1
10 steam generator, which I thought they probably would
11 be finishing up with sometime today.
12 MR. HALE: Hi. This is Steve Hale,
13 NextEra Energy, Point Beach.
14 Yes, we plan to try to answer all of your
15 open questions that you had today by the end of today.
16 That is one we don't have the answer yet, but we will
17 get it for you. All right? Thank you.
18 MEMBER SHACK: Okay.
19 CHAIRMAN BANERJEE: All right, Terry,
20 let's move on then. Okay?
21 MS. DUVIGNEAUD: Good afternoon.
22 My name is DyLanne Duvigneaud. I am a
23 Reactor Engineer in the Accident Dose Branch in NRR,
24 and today I will be speaking to you about the staff's
25 review of the source terms and radiological

1 consequence analysis of the Point Beach EPU.

2 In reviewing the Point Beach EPU source

3 terms for radwaste system analysis, the NRC staff used

4 Matrix 9, Section 2.9.1 of the Review Standard for

5 EPUs.

6 The radiation sources in the reactor

7 coolant and steam were analyzed for EPU conditions.

8 The NRC staff's review considered source terms

9 associated with normal operations and for accident

10 conditions.

11 The NRC staff reviewed if the licensee had

12 adequate capacity for the treatment of gaseous waste

13 and liquid waste. The gaseous and liquid waste

14 sources were evaluated based on source terms for

15 normal operations and anticipated operational

16 occurrences.

17 In regard to the radwaste systems

18 analysis, the NRC staff concludes that the licensee

19 has adequately accounted for the effects of the

20 proposed EPU. The NRC staff also concludes that the

21 licensee has adequately characterized the source terms

22 for the proposed amendment by using NRC-approved codes

23 and guidance.

24 All liquid and gaseous effluents will meet

25 the requirements in 10 CFR Part 20.

1 In conclusion, the NRC staff has reviewed
2 the radioactive source term and the reactor coolant
3 and steam associated with the proposed EPU and
4 concluded that the proposed radioactive source term
5 meets the requirements of 10 CFR Part 20, Appendix I
6 to 10 CFR Part 50, and GDC-60.
7 DR. WALLIS: What is the effect of EPU on
8 these sources? Is it just proportional to the
9 increase in power, roughly speaking?
10 MS. DUVIGNEAUD: Yes, roughly speaking.
11 DR. WALLIS: That's all? There is nothing
12 new?
13 MS. DUVIGNEAUD: No.
14 DR. WALLIS: It is just a proportional
15 increase, right?
16 MS. DUVIGNEAUD: Correct.
17 In a review of the Point Beach EPU design
18 basis accident radiological consequence analyses, the
19 NRC staff used Matrix 9, Section 2.9.2 of the Review
20 Standard for EPUs.
21 By application date of December 8th, 2008,
22 the licensee requested revisions to the Point Beach
23 technical specifications to fully implement the
24 Alternative Source Term.
25 The AST analyzed Point Beach DBA

1 radiological consequences for the proposed EPU power
2 level of 1811 megawatts thermal. The DBAs in the AST
3 were evaluated in accordance with 10 CFR 50.67 and SRP
4 15.0.1 dose acceptance criteria for both offsite and
5 in the control room.
6 The Point Beach EPU Amendment included a
7 revised radiological consequences analysis following
8 an accidental release of waste gas, which was
9 evaluated at the EPU power level of 1811 megawatts
10 thermal.
11 The waste gas release events were
12 evaluated in accordance with 10 CFR Part 20 and
13 GDC-19.
14 The staff review was also conducted in
15 accordance with NRC guidance in Reg Guide 1.183.
16 The revised DBA dose analyses that were
17 submitted in support of the proposed EPU are the
18 following: loss-of-coolant accident, steam generator
19 tube rupture, locked rotor accident, main steamline
20 break, control rod drive ejection, fuel-handling
21 accident, reactor vessel head drop, and three waste
22 gas release events, the gas decay tank rupture, the
23 volume control tank rupture, and the charcoal decay
24 tank rupture.
25 For each of the revised DBAs, the NRC

1 staff performed confirmatory calculations.

2 In regard to the radiological consequences

3 analysis, the NRC staff concludes that the licensee

4 has adequately accounted for the effects of the

5 proposed EPU by using NRC-approved codes and guidance.

6 All DBAs evaluated in the AST meet 10 CFR

7 50.67 and SRP 15.0.1 dose acceptance criteria for both

8 offsite and in the control room.

9 The radwaste release events that were

10 evaluated for the EPU meet the 10 CFR Part 20 and

11 GDC-19 regulatory requirement.

12 The staff concludes that the Point Beach

13 plant site and the dose-mitigating emergency safety

14 features are acceptable within respect to the

15 radiological consequences of postulated DBAs.

16 Therefore, the staff finds the licensee's proposed EPU

17 acceptable with respect to the radiological

18 consequences of DBAs.

19 This concludes my presentation.

20 CHAIRMAN BANERJEE: Thank you.

21 MS. DUVIGNEAUD: Any questions?

22 CHAIRMAN BANERJEE: Any questions?

23 I think you're done.

24 MS. DUVIGNEAUD: Thank you.

25 CHAIRMAN BANERJEE: Okay. Public

1 comments, what is that?

2 MEMBER SHACK: Is anybody out there?

3 CHAIRMAN BANERJEE: Anybody out there who

4 would like to make a comment, public?

5 (No response.)

6 No. Okay. So, I think what we will do

7 now is, if we can, if Point Beach is ready, NextEra,

8 we could take up any discussion of followup items that

9 we had during the day.

10 Is there anything else that we need to do,

11 Terry, today?

12 MR. BELTZ: That is all we had for today.

13 CHAIRMAN BANERJEE: Yes, I think we will

14 keep the material for tomorrow on tomorrow because, as

15 I said, there is another member who will be attending

16 tomorrow who is interested, John Stetkar, on the

17 electrical side of PSA.

18 So, let's take up any followup items.

19 MR. HALE: I'm Steve Hale, NextEra Energy,

20 Point Beach.

21 I wanted to run through the action items

22 that we have collected and provide you the answers to

23 those that we have right now. And, then, we will

24 follow up tomorrow morning. Maybe when we first

25 start, we can hit anything else that we have remaining

1 that is left over today, if that is okay.

2 The one that was just mentioned, the

3 dissimilar metal welds, we are still looking at that.

4 We will get that confirmation for you for Unit 1.

5 So, we are looking at that.

6 For the question that Dr. Bonaca had with

7 regard to current licensing basis, I know that we have

8 had quite a bit of discussion. I don't know if, as a

9 result of sitting through ours and the staff's

10 presentations, whether there are any additional

11 questions in that area.

12 CHAIRMAN BANERJEE: Mario?

13 DR. BONACA: No, that could be sufficient.

14 There is a statement that says that all you heard

15 about, you know, discrepancies between the current

16 license basis now is contained by those standard

17 statements.

18 MR. HALE: Yes.

19 DR. BONACA: And now, I mean, it was just

20 addressed one by one as we worked through.

21 MR. HALE: Okay. So, have we answered

22 your question?

23 DR. BONACA: I guess so.

24 CHAIRMAN BANERJEE: You're not sure?

25 DR. BONACA: I'm not sure. I mean I'm not

1 sure that, if I went through the whole SER, I wouldn't
2 find some other questions there.
3 MR. HALE: Let me run through at least the
4 ones that I am aware of that were raised as part of
5 the review.
6 You heard about the steam generator
7 margin-to-overfill analysis.
8 CHAIRMAN BANERJEE: Yes.
9 MEMBER SIEBER: Right.
10 MR. HALE: In that one, we actually have
11 performed additional analyses beyond what was in our
12 current licensing basis.
13 One other in that same category was the
14 main steamline break full power analysis.
15 MEMBER SHACK: Let me just go over that
16 one again once more.
17 MR. HALE: Okay.
18 MEMBER SHACK: Now you did it with the
19 nominal conditions. Then, you did it with bounding
20 conditions, but no single failure. Is that correct?
21 MR. HALE: We did not do the first
22 analysis with a single failure either.
23 MEMBER SHACK: Okay. But with the
24 bounding analysis and the no single failure, you still
25 had margin to overfill --

1 MR. HALE: Yes.

2 MEMBER SHACK: And that margin is what?

3 MR. HALE: It is about, they are

4 different. I think the EPU value was about 70 cubic

5 feet.

6 MEMBER SHACK: Okay. I thought that was

7 with the nominal conditions, but that is actually with

8 the bounding conditions?

9 MR. HALE: We actually get worse. Our

10 nominal conditions are actually worse than the EPU

11 conditions, which I think Ben was trying to --

12 CHAIRMAN BANERJEE: Yes, he is saying you

13 have less water.

14 MR. HALE: The various effects, you know,

15 decay heat tends to drive more steam out of the

16 faulted generator. So, there are various effects that

17 come into play, but in our case the current licensing

18 basis was more limiting than EPU.

19 CHAIRMAN BANERJEE: What are you talking

20 about, the margin to overfill?

21 MR. HALE: The margin to overfill, yes.

22 CHAIRMAN BANERJEE: Yes. All right.

23 MR. HALE: Yes. Full power main steamline

24 break, that was an event that was not in our current

25 licensing basis, but we felt that we should take on

1 and evaluate as part of the analysis. Some of this
2 has to do with expectations and what other utilities
3 have done before. And that was an event where we went
4 and did additional analysis beyond the current
5 licensing basis.
6 There are several mentioned in the SE.
7 One is feedline break. We do not have an explicit
8 feedline break at Point Beach. However, we provided
9 justification and details as to why we don't need to
10 perform a feedline break. I think the staff performed
11 an independent review and indicated that they agreed
12 with our conclusion with regard to that analysis.
13 DR. BONACA: And you did not need to
14 perform the analysis for designing the modification
15 that you have made?
16 MR. HALE: I'm sorry?
17 DR. BONACA: You did not need to perform
18 the analysis to support the modifications you made to
19 the --
20 MR. HALE: No, no. No, did not.
21 DR. BONACA: Okay.
22 CHAIRMAN BANERJEE: And just very briefly,
23 what was the justification that you provided again?
24 MR. HALE: That a steamline break is
25 bounding from both a core response and a containment

1 integrity standpoint.

2 There were a couple of others. One was, I

3 believe, one you mentioned, Dr. Bonaca, which was

4 inadvertent opening of a PORV.

5 DR. BONACA: PORV, yes.

6 MR. HALE: Yes. Some of the older plants

7 indicated they were bounded by opening of a

8 pressurizer safety valve. I believe that we provided

9 enough information there to demonstrate that that is

10 not a limiting event and not a safety issue.

11 And, then, the only other was CVCS

12 misoperation. This has to do with an overfill event.

13 We do not have full pressure designed safety

14 injection, I mean safety injection pumps, and charging

15 pumps do not start on SI.

16 Being involved with a Seabrook review,

17 which was a four-looper, you know, overfill

18 evaluations on CVCS are more critical because the

19 high-pressure -- I mean the charging pumps are also SI

20 pumps. And so, an overfill is a potential issue with

21 inadvertent SI.

22 But those are the only events where we

23 have actually deviated from the standard review plan

24 that we could find in our view.

25 CHAIRMAN BANERJEE: So, to go over it

1 again, it is the steam generator margin to overfill?
2 MR. HALE: The margin-to-overfill
3 analysis. We did evaluate steam generator tube
4 rupture. We just did not have the thermal hydraulic
5 analysis demonstrating we didn't overfill.
6 CHAIRMAN BANERJEE: Right. And main
7 steamline break, now you did that?
8 MR. HALE: We have done that.
9 CHAIRMAN BANERJEE: Yes.
10 MR. HALE: A full power evaluation, which
11 was not originally in the licensing basis.
12 CHAIRMAN BANERJEE: Feedline break, you
13 justify that because the steamline break is bending?
14 MR. HALE: Yes.
15 CHAIRMAN BANERJEE: Bounding?
16 MR. HALE: Right.
17 CHAIRMAN BANERJEE: Inadvertent opening of
18 PORV, you provided enough information to show that it
19 is not a safety issue?
20 MR. HALE: Right.
21 CHAIRMAN BANERJEE: And CVCS misoperation,
22 the charging pumps don't start on SI, right?
23 MR. HALE: Right, it is not a critical --
24 in other words, there is a long time involved with
25 that being an overfill event.

1 CHAIRMAN BANERJEE: Okay. What were you
2 saying? You had a point for me? Excuse me. Zeyna,
3 did you have a point for me?
4 MS. ABDULLAHI: I was just wondering, I
5 remember a case, I am not really sure, but there was a
6 case where I think it was more of an overpressure
7 credit, I mean to check the containment vessel
8 overpressure, RCS overpressure. And I think the staff
9 asked you to do the case in the SRP where the SRP says
10 -- maybe it was the PORV one, but I don't know. I
11 don't remember which event it was, but what I do
12 remember from the details is that the SRP, they asked
13 you to assume the second safety system will actuate,
14 where in BWR that would be like using a flux scram as
15 opposed to direct scram.
16 And you had said, no, you can't do that.
17 And, then, I think you went back and did the
18 overpressure analysis again with a nominal input or
19 not a tech spec input. The staff rejected it. And
20 eventually, according to the SE -- I do not know the
21 exact communication -- but, eventually, it was
22 accepted based on the RIS saying that no backfit is
23 intended.
24 CHAIRMAN BANERJEE: Okay.
25 MS. ABDULLAHI: So, which event was that?

1 MR. HALE: I was speaking of accident
2 analysis. There are some thermal hydraulic
3 evaluations that you perform, one of which is an
4 overpressure event where you evaluate overpressure of
5 the RCS.
6 MS. ABDULLAHI: Right.
7 MR. HALE: Typically, you will get -- and
8 this is with, I guess, a turbine trip, a specific
9 turbine trip. You are not allowed to credit the
10 reactor trip on turbine trip, and you are not allowed
11 to credit the next reactor trip. You have actually
12 got to go to the second safety-related reactor trip
13 and evaluating the overpressure margin of the reactor
14 coolant system. So, that is the evaluation you are
15 talking about.
16 And you are correct, we did evaluate the
17 SRP criteria for nominal conditions where we went to
18 the second reactor trip. Okay?
19 MS. ABDULLAHI: But, anyway, that is the
20 case where they said it is not our licensing basis --
21 MR. HALE: Good point, good point.
22 MS. ABDULLAHI: -- to do the ASME
23 overpressure analysis.
24 CHAIRMAN BANERJEE: Okay. All right. I
25 noted that.

1 And that is the only, other than accident
2 condition --
3 MR. HALE: No, it is really an evaluation
4 you are required to perform for overpressure related
5 to anticipated occurrences like a turbine trip.
6 CHAIRMAN BANERJEE: Yes.
7 MR. HALE: And you are required, per the
8 SRP, you know, you can get a turbine trip, I mean a
9 reactor trip on turbine trip, but since that is non-
10 safety related, you are not allowed to credit that.
11 And, then, you are also, per the SRP, not
12 allowed to credit the first reactor trip that comes
13 in. So, you go to the second reactor trip.
14 CHAIRMAN BANERJEE: Okay.
15 MR. HALE: And it is really kind of an
16 assessment of overpressure protection for an
17 anticipated event like a turbine trip.
18 DR. BONACA: It is a load reject.
19 MR. HALE: Yes.
20 CHAIRMAN BANERJEE: Okay. So, Mario, that
21 sort of summarizes the situation?
22 DR. BONACA: Yes. I think it is complete
23 now.
24 CHAIRMAN BANERJEE: Yes. Okay.
25 MR. HALE: Okay?

1 MR. HANNEMAN: This is Harv Hanneman from
2 NextEra at Point Beach.
3 I think that last discussion was related
4 to the context of the loss-of-load analysis, which is
5 a design basis accident. We did analyze it, taking
6 credit for the first reactor trip. I think the SRP
7 suggests you should do it eliminating the first trip,
8 and, then, redo it to see what the pressure analysis
9 is for that. That is the thing that we did not
10 completely do.
11 MR. HALE: It was loss of load?
12 MR. HANNEMAN: Loss of load.
13 MR. HALE: Okay. I apologize.
14 MR. HANNEMAN: So, that is one of our
15 design basis accidents.
16 CHAIRMAN BANERJEE: So, if I understand
17 it, if you take the second reactor trip, then you have
18 an overpressure transient which goes above the ASME
19 limits?
20 MR. HALE: It would have a higher
21 pressure.
22 CHAIRMAN BANERJEE: Yes.
23 MR. HALE: Yes.
24 MR. HANNEMAN: Harv Hanneman again.
25 I believe we did an analysis using best

1 estimate for nominal conditions, and that was
2 successful in preventing us from exceeding the ASME
3 limits. But the staff did not totally accept that
4 because we didn't use all of the required assumptions,
5 and so forth.
6 CHAIRMAN BANERJEE: So, where does this
7 stand right now?
8 MR. HALE: The issue has been resolved.
9 CHAIRMAN BANERJEE: Okay.
10 MR. HALE: Okay?
11 MS. ABDULLAHI: The SE accepts it, based
12 on the RIS statement that no backfit is intended, and
13 the acceptance criteria is an emergency level. It is
14 what, 1375 psi for BWRs. I don't know what the PWRs
15 are.
16 CHAIRMAN BANERJEE: Okay.
17 MS. ABDULLAHI: But it is not like a
18 design level pressure. That is why you do the
19 second --
20 CHAIRMAN BANERJEE: That, I think,
21 clarifies the situation.
22 MR. HALE: Okay. All right. Thank you.
23 With regard to Kewaunee, the tubes, steam
24 generator tubes at Kewaunee, the tube size for
25 Kewaunee and Units 1 and 2 at Point Beach are the

1 same. They have the same tube size and tube
2 thickness. There are some slight differences in the
3 number of tube support plates and any vibration bars,
4 but they are generally very similar to each other.
5 That was one of the questions we had.
6 CHAIRMAN BANERJEE: So, I guess the
7 question related to the experience, how long has
8 Kewaunee been --
9 MR. HALE: Well, Harv was actually the
10 Project Manager for the Kewaunee uprate, correct? So,
11 he could probably relate that to you.
12 CHAIRMAN BANERJEE: Okay, go ahead.
13 MR. HANNEMAN: Harv Hanneman from NextEra,
14 Point Beach.
15 CHAIRMAN BANERJEE: Yes.
16 MR. HANNEMAN: Yes, Kewaunee was licensed,
17 I believe, in 1974. Point Beach, Unit 1, started up
18 in 1970. So, they were about four years behind this.
19 Was that your question?
20 CHAIRMAN BANERJEE: No.
21 MR. HALE: No, he was asking about the
22 uprate.
23 CHAIRMAN BANERJEE: Yes.
24 MR. HANNEMAN: Oh, the uprate? Kewaunee
25 did an MUR uprate in 2003, and, then, they did a 6

1 percent stretch-up rate in 2004. And so, they
2 increased their power level from core power level
3 limit of 1650 megawatts thermal. With the MUR and
4 stretch together, they went up to 1772 megawatts
5 thermal, which is getting close to where we are going,
6 propose to go here.
7 CHAIRMAN BANERJEE: Yes. When was this
8 again? How many years ago?
9 MR. HANNEMAN: 2003 for the MUR and 2004
10 for the 6 percent stretch-up rate.
11 CHAIRMAN BANERJEE: And with the 6 percent
12 stretch, you come to conditions which are very similar
13 in the steam generators, and the steam generators are
14 very similar in design?
15 MR. HANNEMAN: Yes. The power levels are
16 very close to where we are going.
17 CHAIRMAN BANERJEE: And the flow rates are
18 about the same in the steam generators?
19 MR. HANNEMAN: Yes, yes.
20 CHAIRMAN BANERJEE: What I am really
21 trying to figure out is, are these steam generators
22 similar in terms of flow conditions to each other?
23 MR. HANNEMAN: Well, let's see, Kewaunee
24 replaced their steam generators, and I don't recall
25 the year. I think it was early 2000, 2001 or `2,

1 something like that.

2 CHAIRMAN BANERJEE: Before the uprate?

3 MR. HANNEMAN: Before the uprate.

4 CHAIRMAN BANERJEE: Yes.

5 MR. HANNEMAN: And they do have slightly

6 larger steam generators than Point Beach. So, they

7 have more number of tubes.

8 CHAIRMAN BANERJEE: They have more tubes?

9 MR. HANNEMAN: More tubes, more heat

10 transfer area, larger secondary inventory volume than

11 Point Beach.

12 CHAIRMAN BANERJEE: But the same --

13 MR. HANNEMAN: The same tube size and --

14 CHAIRMAN BANERJEE: The same tube size,

15 but the amount of heat transferred, the heat transfer

16 area is larger, but is the amount of heat transferred

17 about the same?

18 MR. HANNEMAN: Yes. Yes, their core power

19 limit right now is 1772 megawatts thermal. We are

20 proposing 1800. So, it is very close.

21 MR. HALE: But if you went to what they

22 analyzed at, well, I guess they have an MUR though.

23 MR. HANNEMAN: They have an MUR.

24 MR. HALE: We are probably more comparable

25 to the power level at Ginna, but they are close.

1 MR. HANNEMAN: Yes.

2 MR. HALE: They are very close.

3 MR. HANNEMAN: Our analyzed power level
4 with the .6 percent power uncertainty is 1811
5 megawatts thermal. That is exactly the same as Ginna.

6 CHAIRMAN BANERJEE: Well, maybe what we
7 should do is be a little bit more quantitative on
8 this. Is it possible for us to get the sort of
9 volume-to-energy-transferred or power for the steam
10 generator on the secondary and primary side, compare
11 Kewaunee to Point Beach? You don't have to do it now.
12 But all I am trying to see is, are the velocities
13 likely to be similar on the secondary side?

14 MR. HALE: We do have some backup slides
15 related to the velocities in the Point Beach steam
16 generators.

17 CHAIRMAN BANERJEE: Okay.

18 MR. HALE: We can show that to you.

19 CHAIRMAN BANERJEE: You can show that to
20 us, but, then, you know, what we would be interested
21 -- now I don't know how easy it is for you to get a
22 hold of that information -- is, what are the
23 velocities in any operating steam generator which is
24 very similar? So, if you have got similar velocities
25 in an existing plant which has operated for six years

1 or something without any problems, that is a nice
2 thing to know.
3 MR. HALE: I think from a comparative
4 standpoint we were looking at it on PWR versus BWR.
5 CHAIRMAN BANERJEE: Yes.
6 MR. HALE: CHAIRMAN BANERJEE: We are in
7 the real of about 5 feet per second --
8 CHAIRMAN BANERJEE: Yes.
9 MR. HALE: -- versus 100 feet per second.
10 So, just to give you some relative comparisons and
11 just --
12 CHAIRMAN BANERJEE: Velocity of what
13 there?
14 MR. HALE: Steam in the steam generator.
15 CHAIRMAN BANERJEE: The velocity of steam
16 where?
17 MR. HALE: Through the dryers.
18 CHAIRMAN BANERJEE: Through the dryers?
19 MR. HALE: Yes.
20 CHAIRMAN BANERJEE: But in the tube
21 bundles itself what is the velocity like?
22 MR. HALE: I can't answer that question.
23 CHAIRMAN BANERJEE: Yes. So, in a sense,
24 what I am looking for is to understand if you have had
25 other steam generators where the velocities you are

1 seeing in the tube bundles on the secondary side are
2 similar. And the reason for that is to see if there
3 are likely to be any vibration issues or something
4 like that. And you have got some specific types of
5 plates as well, support plates there, which are these
6 whatever you call them. I know what they are, but --
7 MR. HALE: Broached. Broached.
8 CHAIRMAN BANERJEE: Yes, broached plates,
9 yes. So, that is really the question.
10 MR. HALE: Okay.
11 CHAIRMAN BANERJEE: I don't know if I am
12 stating sort of a vague thing that I am after, but,
13 you know, basically, it is a vibration issue that I am
14 interested in knowing, if there is anything like that,
15 a similar condition somewhere.
16 MR. HALE: And what we had tried to do in
17 the backup slides is --
18 CHAIRMAN BANERJEE: Yes.
19 MR. HALE: -- describe the vibrational
20 analysis that was performed on the Point Beach steam
21 generators. You won't find comparisons to the other
22 steam generators, but we do have backup slides
23 describing the vibration evaluations that were
24 performed.
25 CHAIRMAN BANERJEE: Well, why don't we

1 look at them briefly --

2 MR. HALE: Okay.

3 CHAIRMAN BANERJEE: -- if everybody

4 agrees.

5 MR. HALE: All right.

6 CHAIRMAN BANERJEE: Yes.

7 MR. HALE: That is in the backup slides.

8 Maybe we can pull that up.

9 MEMBER SHACK: But your fretting history

10 at your current power is good?

11 MR. HALE: It's good, right.

12 CHAIRMAN BANERJEE: Of course, your

13 velocities are lower.

14 MEMBER SHACK: Right. So, I mean, you are

15 looking for a sudden --

16 CHAIRMAN BANERJEE: Yes. If there is an

17 increase in velocity, it is on the secondary side, of

18 course.

19 DR. WALLIS: What is the effect on the

20 feed ring?

21 MR. HALE: It is not too bad.

22 DR. WALLIS: But you didn't assess that?

23 MR. HALE: Yes.

24 This is just a picture. I will just walk

25 through.

1 You know, our primary separators are
2 centrifugal-type right above the tube bundle and the
3 feed ring. And, then, they go through the secondary
4 separators, which, as I have described before, are the
5 peerless type of veins that are just pockets and the
6 water falls off.
7 The velocity in our steam separator is
8 going to be on the order of 5.4 feet per second.
9 The vibration evaluations that were done
10 by Westinghouse, we looked at potential in the U-bend
11 in the two-bundle entrance areas. We looked at
12 instabilities, vortex shedding, tube wear.
13 And the analyses that were performed
14 demonstrate that acceptance criteria were met at the
15 EPU conditions.
16 If we can go on to the next slide there,
17 Jay?
18 CHAIRMAN BANERJEE: What do you mean by
19 acceptance criteria there?
20 MR. HALE: In terms of, I guess, flows
21 relative to excitation frequencies and things of that
22 sort. You know, you want to make sure that you are
23 not putting a velocity through there that is going to
24 excite things in terms of vibration.
25 CHAIRMAN BANERJEE: Okay.

1 DR. WALLIS: It is hard to see how you get
2 a factor of 20 below BWRs.
3 MR. HALE: Just the configuration --
4 DR. WALLIS: The overall area isn't all
5 that different, is it?
6 MR. HALE: Well, we have got multiple
7 steam generators, yes.
8 DR. WALLIS: Yes, the area is bigger, but
9 it is not all that big.
10 MR. HALE: I can't speak to it. I can
11 just tell you that we have not had the issues in the
12 PWR areas with steam dryers.
13 CHAIRMAN BANERJEE: Yes, I am not
14 particularly worried about the dryer part of it --
15 MR. HALE: Okay.
16 CHAIRMAN BANERJEE: -- because I realize
17 your dryers are going to have much lower velocities.
18 It is more the tube bundle.
19 MR. HALE: Yes, and we did some of that.
20 Are there any additional slides beyond that, Jay?
21 We did do -- okay, this is steam
22 generators. Okay, I am not sure we have anything
23 beyond --
24 MR. MEYER: What the Chairman is looking
25 for is real-life experience with velocities. We are

1 going to have higher velocities through our tubes, and
2 looking for real-life experiences to give them comfort
3 that that is okay. And we should be able to get that.
4 MEMBER SHACK: This is a Model 44 steam
5 generator. There ought to be a lot of experience with
6 those in the industry.
7 MR. MEYER: We should be able to get --
8 MEMBER SHACK: The question is whether
9 somebody has got a velocity similar to yours.
10 CHAIRMAN BANERJEE: That's right.
11 MR. MEYER: We should be able to get that
12 for you.
13 CHAIRMAN BANERJEE: Yes.
14 MEMBER SHACK: I mean whether it is a
15 four-loop event or --
16 CHAIRMAN BANERJEE: It doesn't matter.
17 MEMBER SHACK: It doesn't matter.
18 CHAIRMAN BANERJEE: It doesn't matter.
19 MEMBER SHACK: The tube will never know.
20 MEMBER SIEBER: It is the velocity on the
21 outside of the tube. Now where in this model steam
22 generator -- in the old ones, it seemed to have
23 occurred at the AVB locations, which is about the
24 broached tube support plates.
25 MR. HALE: Right.

1 MEMBER SIEBER: When you do your steam
2 generator tube examinations, can your probe get up
3 into the AVB area? Can it go around -- I know you
4 can't do it in the center of the bundle. The question
5 is, can you do it anyplace, and do you do it?
6 MR. HALE: I can't answer that question.
7 I don't know if we have it.
8 MEMBER SIEBER: Because that would tell
9 you something about the effects of it --
10 CHAIRMAN BANERJEE: Yes.
11 MEMBER SIEBER: -- in the worst locations,
12 yes.
13 MR. HALE: I know, historically, that
14 Westinghouse steam generators haven't had an issue
15 with vibration --
16 MEMBER SIEBER: Yes, they are like
17 hairpins that stick in there.
18 MR. HALE: Yes.
19 MEMBER SIEBER: And they contact the
20 tubes, and they do vibrate.
21 CHAIRMAN BANERJEE: We will keep this
22 question. I mean it may not be that easy to answer
23 because you may not have instant access to other data.
24 MR. MEYER: Kewaunee should be a pretty
25 close comparison, I would think.

1 CHAIRMAN BANERJEE: Yes.

2 MR. MEYER: So, we will look.

3 MEMBER SIEBER: I don't know that analysis

4 is going to tell you that much, but --

5 CHAIRMAN BANERJEE: Not an analysis. I

6 was looking for a real-life experience.

7 MEMBER SHACK: Westinghouse ought to have

8 enough sort of empirical data on these things. You

9 know, that is how they set the acceptance criteria,

10 presumably.

11 CHAIRMAN BANERJEE: Yes.

12 MEMBER SIEBER: Well, this has been an

13 issue back in the 1980s, the AVB wear. And so, if you

14 can find that with your steam generator inspection

15 program before it becomes a leaker, that would give

16 you some satisfaction that perhaps, even if the

17 vibration, where it does exist, that you will catch it

18 before it becomes a leaker or a rupture.

19 MR. HALE: Well, we will leave that action

20 open. What I am hearing is two areas, you know,

21 operational experience in terms of velocities relative

22 to other similar plants, and, also, some information

23 relative to our steam generator inspections in the

24 anti-vibration bar area.

25 CHAIRMAN BANERJEE: So, I will call that

1 3A and 3B.

2 MR. HALE: Okay.

3 CHAIRMAN BANERJEE: Two things.

4 MR. HALE: All right.

5 MEMBER SIEBER: Well, a lot of the wear,

6 it is dependent on velocities and turbulence, but it

7 also depending in fit --

8 MR. HALE: Yes.

9 MEMBER SIEBER: -- of the AVB and whether

10 the tubes are straight or not. So, there are a lot of

11 factors involved.

12 CHAIRMAN BANERJEE: Okay.

13 MR. HALE: Okay. The next item I had was

14 the question regarding the DNBR variations and limits

15 and rationale. I know that Ben Parks touched on it in

16 his presentation, and Jay can talk through those.

17 MR. KABADI: Yes. I think one thing -- I

18 am Jay Kabadi, NextEra.

19 But does that answer the question or

20 anything else?

21 CHAIRMAN BANERJEE: Yes, I think for me I

22 got sufficient answer on that from Ben, if you agree

23 with his answer.

24 MR. KABADI: Right. That is actually the

25 same thing I was going to say, what Ben Parks said.

1 CHAIRMAN BANERJEE: All right.

2 MR. HALE: Okay. The next action I had

3 had to do with the average PCT and some of that

4 discussion. I believe Ben Parks also --

5 DR. WALLIS: Now you say it was 600

6 degrees lower than the --

7 CHAIRMAN BANERJEE: Is that what you have

8 as well? I mean you did this independently.

9 MR. HALE: Yes. Yes, it would be

10 consistent, and we had provided that information to

11 the staff.

12 CHAIRMAN BANERJEE: So, your best estimate

13 temperatures, whether median or not, is on the order

14 of 1300 --

15 MR. HALE: Yes.

16 CHAIRMAN BANERJEE: -- compared to 1900?

17 DR. WALLIS: That is the problem with the

18 95/95. What you get is an outlier, and the outlier

19 could lie over a pretty wide range because it is right

20 on the tail of things. So, you may be 95 percent

21 confident, but that could vary quite a bit when you do

22 two different runs.

23 CHAIRMAN BANERJEE: Yes, but the whole

24 purpose of the methodology is actually that this 95

25 percent --

1 DR. WALLIS: Your confidence is pretty
2 confident as to load, that value, that's right.
3 CHAIRMAN BANERJEE: Right. Okay. Go
4 ahead.
5 MR. HALE: And so, if that is okay --
6 CHAIRMAN BANERJEE: Yes, I think it is
7 fine.
8 MR. HALE: Okay.
9 CHAIRMAN BANERJEE: Yes.
10 MR. HALE: There was a question on reflux
11 cooling and loop seal clearing time.
12 CHAIRMAN BANERJEE: Right.
13 MR. HALE: The Westinghouse analysis did
14 indicate a short period of reflux cooling, and their
15 loop-clearing time was about 230 seconds.
16 CHAIRMAN BANERJEE: Okay. So, that is a
17 little different from the answer that we got from Len
18 Ward, who said there was about a period of 300 to 400
19 seconds of refluxing.
20 MR. HALE: Yes.
21 CHAIRMAN BANERJEE: But it is of the same
22 order.
23 MR. HALE: Yes.
24 CHAIRMAN BANERJEE: I think an ancillary
25 question was that, suddenly, they had -- so, to begin

1 with, the concern comes from the fact that you have
2 got higher velocities now due to -- well, not
3 necessarily higher velocities, but higher qualities,
4 okay, because you have got the same -- in your small-
5 break LOCA, you have got more decay heat. So, you are
6 generating more steam in a small-break LOCA.
7 MR. HALE: Right.
8 CHAIRMAN BANERJEE: And if you generate
9 more steam, it gives you a higher velocity in the hot
10 leg, which is going to the steam generator, and it is
11 condensing and it is running back in this reflux mode
12 to the core.
13 MR. HALE: Yes.
14 CHAIRMAN BANERJEE: And it goes
15 countercurrent to the steam flow. As the steam flow
16 increases, it tends to hold up the water. If it
17 eventually doesn't allow the water flow back, then it
18 accumulates in the steam generator and depresses the
19 core level. And this has been seen in experiments.
20 And the problem arises, if there is a
21 problem, because your pipes are remaining the same
22 size. So, the steam velocity is going up.
23 DR. WALLIS: Because the water velocity is
24 going up, too, isn't it?
25 CHAIRMAN BANERJEE: And coming back is

1 going up, too. So, the issue is, do these codes
2 handle flooding properly? The reason the question
3 arises is this is a fairly large power uprate compared
4 to other power uprates.
5 DR. WALLIS: The effect has been known for
6 many years.
7 CHAIRMAN BANERJEE: The effect has been
8 known. It is a question of whether the codes handle
9 them correctly.
10 DR. WALLIS: So, if they haven't handled
11 it correctly, it has been there for a decade.
12 CHAIRMAN BANERJEE: It may not matter with
13 the existing plants except for the EPR. You know, if
14 you do the calculation by hand, you see that you don't
15 get extensive periods of flooding; whereas, this is a
16 plant where we have to check that.
17 Len is going to give us his numbers, so I
18 can work it out by hand and take a look at it.
19 DR. WALLIS: If they were 20 percent away
20 before, they must have checked it then, it seems to
21 me.
22 CHAIRMAN BANERJEE: Anyway, don't worry
23 about it. He assures me that they have flooding in
24 the tubes. Whether they have it at the elbow of the
25 hot leg is what needs to be --

1 DR. WALLIS: Do they have it in the steam
2 generator tubes?
3 CHAIRMAN BANERJEE: Yes. So, he knows
4 that problem.
5 MR. HALE: Do you need anything else from
6 us on this issue?
7 CHAIRMAN BANERJEE: I think we will wait
8 for the staff to get back to us on that.
9 MR. HALE: Okay.
10 CHAIRMAN BANERJEE: Yes, I think we are
11 clear on this.
12 MS. ABDULLAHI: That will be next week.
13 CHAIRMAN BANERJEE: Yes, that's fine.
14 MS. ABDULLAHI: Not tomorrow or today.
15 CHAIRMAN BANERJEE: Yes, that's fine. We
16 will get it, if we need something, we will communicate
17 to -- you know, Zeyna will get in touch with the
18 appropriate people, and we will get the information.
19 It is just a check for ourselves.
20 MR. HALE: Okay.
21 CHAIRMAN BANERJEE: It is not a crucial
22 point.
23 MR. HALE: And, then, I had two
24 additional. One we will discuss tomorrow on LOFTRAN.
25 There was some interest in some of the baselining of

1 LOFTRAN against actual plant performance as part of
2 power ascension testing. We will address that one
3 tomorrow as part of our power ascension testing
4 discussion.
5 CHAIRMAN BANERJEE: Yes.
6 MR. HALE: And, then, the other one I have
7 is some additional information regarding the bases
8 behind the half-mixing volume and the boron
9 precipitation analysis.
10 So, what we would carry forward until
11 tomorrow was the dissimilar metal welds on Unit 1 and
12 weld overlay.
13 CHAIRMAN BANERJEE: Yes.
14 MR. HALE: The discussion on steam
15 generator performance with the velocities --
16 CHAIRMAN BANERJEE: Yes.
17 MR. HALE: -- and some historical
18 perspective on our inspections in the anti-vibration
19 bar area.
20 The LOFTRAN discussion, which we will
21 carry forward and discuss during our power ascension
22 discussion, and the half-mixing volume, which we will
23 carry over.
24 CHAIRMAN BANERJEE: All right.
25 MR. HALE: I hope I captured everything.

1 CHAIRMAN BANERJEE: I think you have.

2 DR. WALLIS: I am still puzzled about that

3 fouling --

4 MR. HALE: Oh, I am sorry. That was the

5 other one.

6 DR. WALLIS: -- of the fan coolers,

7 because the usual use of fouling is to say that it

8 might happen, so you had better take care of it. So,

9 it could be as big as this and we are going to adjust

10 our heat transfer according. That is really a

11 conservative upper bound to the fouling. It could be

12 as big as this, so we have to worry about it.

13 In the fan coolers you are worried about a

14 lower bound. I mean it must be as big as this in

15 order to help you. So, you are looking at a

16 conservative lower bound, which seems to me ought to

17 be zero.

18 What is the lowest fouling you can

19 guarantee is there, is what you are asking for. And

20 that could be zero, it seems to me.

21 The thing you have got in the handbook is

22 the conservative upper bound, not the conservative

23 lower bound. So, I am not sure what the basis is for

24 estimating what is a realistic assumption about

25 fouling.

1 CHAIRMAN BANERJEE: Can we just clarify
2 that point? This is also an action on the staff to
3 clarify in their SE, yes.
4 DR. WALLIS: Right.
5 CHAIRMAN BANERJEE: So, I don't know
6 whether this should be -- I think take a look at it.
7 DR. WALLIS: It may already resolve easily
8 and then --
9 CHAIRMAN BANERJEE: And we will also have
10 the staff talk on it.
11 DR. WALLIS: Yes.
12 CHAIRMAN BANERJEE: So, we will resolve
13 this, hopefully, before we do anything.
14 There was one other clarification which I
15 just want to be sure that we got the right picture.
16 If you go back to your GSI-191 slide, you have a slide
17 which shows the 4.2-feet available NPSH. I just want
18 to be clear that that NPSH is arising without any need
19 for any containment pressure other than atmospheric
20 pressure.
21 MR. HALE: That is correct.
22 CHAIRMAN BANERJEE: Okay.
23 DR. WALLIS: And it is assuming that the
24 water is at 212.
25 MR. HALE: Right.

1 DR. WALLIS: So, it is boiling. So, it is
2 the worst-possible situation.
3 CHAIRMAN BANERJEE: Yes. We just want to
4 be sure of that. And if I understand, the screen is
5 about 2 feet below, so that about half of that
6 available at the screen rather than the full 4 feet,
7 is that correct? I am just trying to fix where the
8 position of the screen is.
9 DR. WALLIS: Well, what part of the
10 screen? The top of the screen is different from the
11 bottom of the screen.
12 CHAIRMAN BANERJEE: That is true, yes.
13 Because these, I imagine, are these sort of --
14 MR. TOMASZEWSKI: Dan Tomaszewski,
15 NextEra.
16 That is 4.2 feet of margin is at the
17 minimum water level in the containment --
18 CHAIRMAN BANERJEE: Okay.
19 MR. TOMASZEWSKI: -- that you need to go
20 on recirc.
21 CHAIRMAN BANERJEE: Maybe if you would
22 just give us a little sketch of this to show us where
23 the water level is? The screens themselves are sort
24 of vertical, aren't they? They are stacked?
25 MR. MEYER: Yes, they run horizontally,

1 but they are vertically-stacked.

2 CHAIRMAN BANERJEE: Yes, vertically-

3 stacked. And the water level you are talking about is

4 above the top of these screens? How big are these

5 screens? It would be nice if you would just give us a

6 little sketch to see this.

7 The one thing I would sort of also --

8 MS. ABDULLAHI: With time?

9 CHAIRMAN BANERJEE: I'm sorry?

10 MS. ABDULLAHI: With time?

11 CHAIRMAN BANERJEE: Well, the minimum is

12 enough. I mean it doesn't matter. Why would I need

13 it with time?

14 MS. ABDULLAHI: Because the delta P

15 changes, right, and you want to know where the delta

16 P, what the pressure drop is, and you want to see if

17 the amount available is equivalent to what they need.

18 CHAIRMAN BANERJEE: But this is the NPSH.

19 MR. HALE: This is the minimum available.

20 CHAIRMAN BANERJEE: Yes.

21 MS. ABDULLAHI: The minimum available.

22 DR. WALLIS: If you actually took 2.4

23 feet, you might well flash the water there.

24 MS. ABDULLAHI: At 212 temperature.

25 DR. WALLIS: Because it is already at

1 boiling, and you decrease the pressure.

2 CHAIRMAN BANERJEE: Sorry?

3 DR. WALLIS: I say, if it is already at

4 212, and if you take this 4.2-feet pressure drop

5 through the screen, then you are going to flash,

6 possibly flash some water, which is why you need the

7 overpressure margin.

8 MS. ABDULLAHI: That is the question that

9 needs to be explained.

10 DR. WALLIS: Right.

11 CHAIRMAN BANERJEE: Well, if it is 4.2, it

12 depends on the pressure loss across the screen, right?

13 DR. WALLIS: That is what I mean. If you

14 decrease the pressure below the atmospheric, because

15 that is what you do at the screen, you could flash

16 that water.

17 CHAIRMAN BANERJEE: You know, they have to

18 address that issue for GSI-191.

19 DR. WALLIS: Well, it flashes when it goes

20 through the pipe, too, doesn't it? I mean the

21 pressure is dropping all the way through there before

22 it gets to the pump.

23 CHAIRMAN BANERJEE: But the pump is 27

24 feet below, and the total frictional pressure loss is

25 7 feet.

1 DR. WALLIS: It depends on the design of
2 the piping. Does the piping have friction loss and
3 the --
4 (Simultaneous speakers.)
5 DR. WALLIS: -- goes down?
6 CHAIRMAN BANERJEE: Sure. The details
7 matter. The details matter.
8 DR. WALLIS: So, the details matter, yes.
9 CHAIRMAN BANERJEE: Yes, the details
10 matter.
11 Probably, I mean from my point of view,
12 this has to be closed as a separate issue for GSI-191,
13 but we are just looking at it. We are not going to
14 resolve this now.
15 You are simply saying, the way I
16 understand it -- let me give it back to you the way I
17 see it. You are doing all the testing and everything
18 that is needed to resolve GSI-191, including removing
19 insulation and everything else, taking EPU conditions
20 into account.
21 MR. HALE: Right.
22 CHAIRMAN BANERJEE: So, when you resolve
23 GSI-191, you will have resolved the situation with
24 regard to the EPU.
25 MR. HALE: That is correct.

1 CHAIRMAN BANERJEE: So, that is the
2 situation.
3 MR. HALE: Right.
4 CHAIRMAN BANERJEE: Now let me caution you
5 about one thing. You are fairly unique plant compared
6 to the PWR OG in relation to how you are doing
7 injection. So, to reference the PWR OG experiments,
8 you would have to have a clear rationale for that.
9 It is nothing that concerns us here, but
10 it just something for you to know for your GSI-191
11 resolution. I am sure the staff will need to show
12 that you can reference these experiments, which don't
13 necessarily have the same injection methodology as you
14 have. Okay?
15 That's about it.
16 And I think, with that, we have --
17 MR. HALE: We have covered everything that
18 I can think of.
19 CHAIRMAN BANERJEE: Yes, I think you have
20 covered everything. I have starred the items which
21 you will cover tomorrow. We will come back to them.
22 If you can cover them in the morning, fine, whenever
23 you can.
24 MR. HALE: Yes, our intent would be to try
25 to address all of these with the exception of the

1 LOFTRAN, because I think it fits in more with the
2 power ascension test discussion.
3 CHAIRMAN BANERJEE: You can do it as you
4 like.
5 MR. HALE: Right. The dissimilar metal
6 welds, the discussion on experience with velocities in
7 steam generators and our inspection capability with
8 steam generators, the LOFTRAN, and the fouling of the
9 fan coolers.
10 CHAIRMAN BANERJEE: If you can't resolve
11 it tomorrow, you can resolve it in between now and the
12 full Committee meeting because we are going to try to
13 write a letter at the full Committee meeting.
14 Okay. I think, with that, I will just go
15 around one last time and see if any of us have any
16 questions.
17 DR. WALLIS: No, I was quite pleased
18 really with what I heard today. I think you did a
19 nice job. And there are a few of these things to tie
20 up, but generally I am quite pleased.
21 CHAIRMAN BANERJEE: You can also, of
22 course, address some issues to the staff, if you like,
23 if you have anything to ask them, other than the
24 fouling of the fan coolers.
25 All right. Jack, are you all right?

1 MEMBER SIEBER: I have no additional
2 questions or comments.
3 CHAIRMAN BANERJEE: Okay. And, Bill, are
4 you okay?
5 MEMBER SHACK: I am fine.
6 CHAIRMAN BANERJEE: Mario, do you have
7 anything?
8 DR. BONACA: I am okay. I am quite
9 impressed with the improvements in the feedwater
10 system. And clearly, it is paying a lot of benefits.
11 CHAIRMAN BANERJEE: Yes. Thanks.
12 So, I would like to agree with Mario that
13 it is impressive, the things you are doing. I think
14 that really has great safety benefits. It is very
15 helpful.
16 So, thank you for your presentation. I
17 would like to thank the staff as well. I think both
18 the presentations were excellent. So, we look forward
19 to tomorrow.
20 So, with that, I am going to break, and
21 then we will come back at 8:30, if I can make it.
22 Okay. Ivan, do you have any questions?
23 DR. MALDONADO: No. I am quite pleased.
24 I am very impressed by how open and forthright
25 everything has gone.

1 CHAIRMAN BANERJEE: Okay. So, he seconds
2 our opinion.
3 So, thank you very much.
4 And we will break until tomorrow. Off the
5 record.
6 (Whereupon, at 4:41 p.m., the proceedings
7 in the above-entitled matter were adjourned.)
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Point Beach
Extended Power Uprate (EPU)
ACRS Subcommittee

February 24-25, 2011

Agenda

- **EPU Overview**
  - Background…… **Larry Meyer**
  - Modifications and Unique Features…… **Steve Hale**
- **Fuel and Core…….. Jay Kabadi**
- **Safety Analyses…….. Jay Kabadi**
  Steve Hale
- **Probabilistic Safety Assessment……. Anil Julka**
- **Electrical …… Steve Hale**
- **Human Performance & Ops Training**
  & Emergency Operating Procedures……. Mike Millen
- **Power Ascension and Testing…….. Mike Millen**
- **Acronyms**

NEXTera ENERGY POINT BEACH

NEXTera ENERGY POINT BEACH

Point Beach History

- **Located in Wisconsin on the west shore of Lake Michigan**
  - Westinghouse 2-Loop Nuclear Steam Supply System (NSSS)
  - Bechtel original Architect – Engineer (AE)
  - Once through condenser cooling
- **Original full power operating licenses**
  - 1970 for Unit 1; 1973 for Unit 2
- **Steam Generators (SGs) replaced in 1983 for Unit 1 and 1996 for Unit 2**
- **Measurement Uncertainty Recapture (MUR) increased licensed core power level to 1540 MWt in 2002**
- **Unit 1 and Unit 2 Reactor Vessel Heads replaced in 2005**
- **Renewed Operating Licenses issued in 2005**
- **NextEra Energy purchased plant in late 2007**

NEXTera ENERGY POINT BEACH

NextEra is requesting approval of a 17% extended power uprate of the Point Beach units

- 17% EPU requested at a licensed core power level of 1800 MWt
- Some plant modifications implemented in 2009 and 2010
- Planning to implement the final upgrades in Spring 2011 outage on Unit 2 and Fall 2011 outage on Unit 1

NEXTera ENERGY POINT BEACH

MORE Generation for OUR NEXT Generation

One Team - One Goal - POWER UP!

POWER UPRATE

POINT BEACH POWER UPRATE PROJECT

NEXTera ENERGY POINT BEACH

Power Uprate for A Better Plant

- **A Safer Plant**
  - Upgraded Auxiliary Feedwater system
  - Upgraded Control Room ventilation system
  - Improved plant risk profile (CDF and LERF)
- **More Operational Margin**
- **More Reliable**
- **Many Important Legacy Issues Resolved**
- **Design Basis and Analysis Improved**
- **Other Benefits include:**
  - Meet customers energy needs with zero greenhouse gas emissions
  - Cost-effective production of electricity for customers

More Generation for Our Next Generation

NEXTera ENERGY POINT BEACH

EPU is a site wide initiative with extensive involvement of site personnel

- **Project team is comprised of individuals with significant nuclear and uprate experience**
- **Integrated with site personnel and operations**
- **Licensed Senior Reactor Operators (SRO) on team**
  - 5 to 10 SROs supporting
- **Site design engineers on team**
  - EPU engineering reports through Site Engineering Director
- **Site personnel input and review integrated throughout the project**
  - Intensive ownership and teamwork
  - Pride in online work performed safely
  - 2,000,000 work hours without injury
  - Thousands of online terminations made without event

NEXTera ENERGY POINT BEACH

Margin management was addressed as part of the EPU system and component evaluations

- Plant personnel involvement assure preservation of adequate design and operating margins
- Engineering and Operations involved in margin reviews
- Margins improved through analyses, modifications and material upgrades
- Strong station ownership of margins

EPU License Amendment Request (LAR) was prepared utilizing the guidance of RS-001, Review Standard for Extended Power Uprates

- Addressed lessons learned from previous EPU reviews (Ginna 17% EPU implemented in 2006)
- Evaluations consistent with Point Beach Current Licensing Basis (CLB) per RS-001

Other 10 CFR 54 considerations were evaluated

- EPU system and component evaluations addressed impact on renewed licenses
- Evaluations of proposed 17% EPU included updates to Time Limited Aging Analyses (TLAAs), as required

NEXTera ENERGY POINT BEACH

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- **Acronyms**

Plant Changes

- Parameters
- Technical Specifications
- Methodology/Codes
- Modifications

NEXTera ENERGY POINT BEACH

Proposed power level is consistent with previously approved uprates of similar vintage and design

- **Consistent with other two-Loop Westinghouse Pressurized Water Reactors (PWRs) with similar Westinghouse 14 x 14 422 Vantage+ Fuel**
  - Ginna implemented 17% EPU in 2006
    - -- Licensed Core Power Level - 1775 MWt
  - Kewaunee implemented 6% SPU in 2004
    - -- Licensed Core Power Level - 1772 MWt

NEXTera ENERGY POINT BEACH

Analyses were performed to bound the design parameters

Parameter	Original	Current (1.4% MUR)	EPU	EPU Change
Core Power (MWt)	1518.5	1540	1800	+260
Taverage (°F)	557.0 - 574.0	558.1 - 574.0	558.0 - 577.0	-0.1 / +3.0
Delta T (°F)	59.3 – 58.2	60.1 – 59.0	69.8 - 68.2	+9.7 / +9.2
Thermal Design Flow (gpm/loop)	89,000	89,000	89,000	0
Steam Pressure (psia)	612 - 857	664 - 800	601 - 755	-63 / -45
Moisture Carryover (maximum, %)	0.10	0.10	0.25	+0.15
Steam Mass Flow (10^6 lb/hr)	6.55 - 6.60	6.72 - 6.75	7.36 - 8.13	+0.64 / +1.38

NEXTera ENERGY POINT BEACH

A comprehensive evaluation of integrated plant impacts was performed

- **Major Balance of Plant (BOP) parameters used for BOP analysis and evaluations**
  - Main Steam Generator outlet pressure and temperature
  - Final Main Feedwater inlet temperature to Steam Generators
  - Circulating Water temperature to condenser
  - High Pressure Turbine inlet pressure and temperature
- **Heat balances developed for current power level and EPU NSSS power level of 1806 MWt (core + pump heat)**
- **Hydraulic analysis performed on feedwater, condensate and heater drain systems**
- **Plant normal, off-normal and transient conditions evaluated**

NEXTera ENERGY POINT BEACH

Related license amendments have been approved or will be approved prior to approval of the EPU License Amendment Request

- **Related License Amendments**
  - License Amendments 235 (U1) and 239 (U2): ASTRUM Best Estimate Large-Break Loss of Coolant Accident (LOCA) Methodology
    - -- Analyses performed at EPU conditions
    - -- Approved and implemented in 2009
  - License Amendment Request 241: Alternative Source Term (AST)
    - -- Radiological accident analyses performed at EPU conditions
  - NRC issuing separate license amendments for AFW and RPS/ESFAS even though part of the original EPU LAR

NEXTera ENERGY POINT BEACH

Proposed Technical Specifications changes improve safety, reliability and safety system availability

- **RPS/ESFAS (TS 3.3.1 and 3.3.2)**
  - EPU requirements
  - Non-EPU changes
  - New ESFAS function
    - -- AFW pump low suction pressure automatic switchover to Service Water
  - Technical Specification Task Force (TSTF) 493, Revision 4, “two column” format
    - -- Allowable Value (AV) and Nominal Trip Setpoint (NTSP)
    - -- New notes to address as-left and as-found calibration values
  - Revised setpoints based on uncertainty calculations utilizing double-sided random instrument uncertainties to support AVs and NTSPs

NEXTera ENERGY POINT BEACH

Proposed Technical Specifications changes improve safety, reliability and safety system availability (continued)

- **AFW (TS 3.7.5)**
  - Addresses AFW system upgrades
  - One of two AFW pump systems can be inoperable for 72 hours (reduced from 7 days)
  - AFW implementation includes other Tech Spec changes
    - -- TS 3.3.4 Safeguards bus loss of voltage relay time delays
    - -- TS 3.3.2 ESFAS function for AFW pump switchover to Service Water
    - -- TS 3.7.6 Condensate Storage Tank (CST) inventory requirements
    - -- TS 3.8.1 Emergency Diesel Generator Testing

NEXTera ENERGY POINT BEACH

Proposed Technical Specifications changes improve safety, reliability and safety system availability (continued)

- **Other EPU Tech Spec Changes**
  - TS 1.1: Definition of Rated Thermal Power
  - TS 2.1: Departure from Nucleate Boiling Ratio (DNBR) Correlation
  - TS 3.2: Axial Flux Difference Change - Relaxed to constant axial offset control
  - TS 3.4.1: RCS Pressure, Temperature and Flow DNB Limits
  - TS 3.4.9: Pressurizer Water Level Increase to 52%
  - TS 3.4.10: Reduced Tolerance on Pressurizer Safety Valve Lift Setting
  - TS 3.5.1&4: Increased Minimum Boron Concentrations
  - TS 3.7.1: Reduced lift settings for some of the Main Steam Safety Valves
  - TS 3.7.3: Revised Main Feedwater Isolation for new Main Feedwater Isolation Valves (MFIVs)
  - TS 5.6: Revised Core Operating Limits Report (COLR)

NEXTera ENERGY POINT BEACH

NRC pre-approved codes and methodologies were used

- **Code and Methodology Changes**
  - WCOBRA/TRAC with ASTRUM – Large Break LOCA
  - RAVE – Loss of flow and locked rotor analyses
  - RETRAN – Non-LOCA transients
  - LOFTTR2 – Steam Generator Tube Rupture
  - VIPRE – DNB analysis of the nuclear fuel
  - GOTHIC – LOCA and Steam Line Break (SLB) containment integrity analyses

NEXTera ENERGY POINT BEACH

High Energy Line Break (HELB) Outside Containment Program documentation improved

- Calculations and supporting documentation updated to improve quality and validation of the HELB Program
- Pipe Break methodology changed to utilize ASME code equations
- Postulated breaks and mass and energy release performed at EPU conditions
- GOTHIC used for determining HELB area pressures and temperatures
- No changes required for mitigating features
- Environmental Qualification (EQ) addressed as part of Electrical Impacts

NEXTera ENERGY POINT BEACH

Eliminated post LOCA vital access requirement in Primary Auxiliary Building (PAB) to reduce operator radiation exposure

- **Eliminated Post Accident Sampling System (PASS) requirement to sample and analyze within 3 Hours**
  - Implement Westinghouse Owner Group Core Damage Assessment Guidance (WCAP-14696-A)
  - Enhanced use of plant data for indication of core damage using indicators based on fixed plant instrumentation
- **Eliminated need to reset Motor Control Center (MCC) breakers for Control Room Emergency Filtration System (CREFS) fan motors**

NEXTera ENERGY POINT BEACH

Modifications

- **Three categories of major plant modifications**
  - Safety improvements
  - Modifications to reduce overall plant risk profile
  - Modifications needed to support power generation at EPU power level

NEXTera ENERGY POINT BEACH

Implementing AFW modifications that improve safety margins, system reliability and availability

- **New, higher capacity, "unitized" motor-driven Auxiliary Feedwater pumps in Primary Auxiliary Building (PAB)**
- **Maintain existing AFW pumps as standby pumps**
- **Improve 480 V bus margins during Loss of Offsite Power**
- **Elimination of manual operator actions**
  - Automated suction switchover to safety related water supply
  - Increased backup air supply for AFW pump mini-recirculation valves
  - Eliminated manual alignment of shared motor-driven AFW pumps

NEXTera ENERGY POINT BEACH

Modifications are being implemented that improve safety and plant margins

- **Fast acting Main Feedwater Isolation Valves**
  - Improves containment peak pressure response to main steam line breaks
- **Loss of voltage relay time delay setting changes**
  - Improves ability to maintain off-site power during transmission grid voltage transients
- **RPS/ESFAS setpoint changes**
- **New Main Generator output breakers**

Modifications and changes are being implemented to improve the overall plant risk profile

- AFW automatic suction switchover to safety related water supply
- Increased backup air supply for AFW mini-recirculation valves
- Eliminated manual alignment of shared motor-driven AFW pumps
- Defense in depth by retaining existing shared AFW pumps as standby pumps
- Providing self-cooled air compressor
- Procedure change to improve reliability of RCS depressurization

Other modifications being implemented to support operations at EPU power level will improve operating margins and reliability

- **Increased equipment capacity**
- **Improved performance and reliability**
- **Improved operating margins**
- **Obsolete instrumentation replacement**
  - More accurate and reliable components
- **Single failure vulnerabilities addressed**
- **Material enhancements to address flow accelerated corrosion and vibration**
- **Lessons learned from industry experience incorporated**

NEXTera ENERGY POINT BEACH

Secondary side modifications support operation at EPU Power Level, improve margins and reliability

- **High pressure turbine steam path, control valves and inlet piping**
- **Main unit generator rotor replacement and rewind**
  - Includes cooler and exciter upgrades
- **Replacement of main feedwater and condensate pumps and motors**
- **Replacement of feedwater heaters and level controls**
- **Replacement of Main Step-Up Transformers**
- **Replacement of steam generator secondary moisture separators for reduced moisture carryover**

NEXTera ENERGY POINT BEACH

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No significant changes to fuel design is necessary for EPU

- **Advanced fuel design (14x14 422V+) implemented in previous cycles**
- **Minor changes in fuel rod loading to accommodate higher fission gas release associated with EPU**
  - Annular blanket size increased from 6 to 8 inches
  - ZrB_2 Integral Fuel Burnable Absorber concentration reduced from 1.5x to 1.25x
- **Peak Rod and Assembly burnup will be maintained within current limits**

NEXTera ENERGY POINT BEACH

Margins to key safety parameters are maintained

- **Core design limits reduction offsets effect of EPU and maintain margins to fuel design limits**
  - Hot Channel Enthalpy Rise Factor ($F_{\Delta H}$) core design limit reduced from 1.77 to 1.68
  - Axial offset operating band is reduced to move from RAOC to CAOC (similar to early cycle operation)
- **Normal incore fuel management methods utilized to meet reduced limits**
  - Feed enrichment & feed batch size
  - Burnable absorber placement
  - Core Loading pattern
- **Margin to key safety parameter limits maintained**
  - Variations within normal cycle variations
- **Shutdown Margin requirement is changed**
  - Accommodates larger Doppler power defect
- **RCS Boron requirements remain within system capability**
  - Boron concentrations increase by ~ 300 ppm

NEXTera ENERGY POINT BEACH

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Safety Analyses

- **Methods**
  - Non-LOCA
  - LBLOCA
  - SBLOCA
- **LOCA Long Term Considerations**
- **Dose Consequences**
- **SGTR**
- **Containment**

NEXTera ENERGY POINT BEACH

Safety Analyses: Conservatisms/Improvements

- **Key changes beneficial to safety analysis**
  - Improved methods
  - Reduction of hot channel enthalpy rise factor ($F_{\Delta H}$)
  - Reduction in axial offset
  - Improvements in AFW system
- **Conservative inputs/assumptions**
  - Conservative physics parameters
  - Bounding plant operating parameters
  - Conservative trip setpoints
- **Conservative analysis DNBR limit**
  - Safety Analysis Limit (SAL) for DNBR is set conservatively to maintain margin to the DNBR design limit

NEXTera ENERGY POINT BEACH

Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria

Method	Pre- EPU	EPU
Non-LOCA	LOFTRAN Computer Code	RETRAN Computer Code
	Point Kinetics Neutronics for Loss of Flow and Locked Rotor Analyses	3-D Neutronics for Loss of Flow and Locked Rotor Analyses (RAVE)
	No Thick Metal Mass Credited	Methodology for Reactor Coolant System Thick Metal Mass Heat Transfer Model
	Full Power Steam Line Break not in CLB	Full Power Steam Line Break Analyzed

Codes and methodologies are NRC approved

NEXTera ENERGY POINT BEACH

Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
Decrease (Loss) in RCS Flow (Reduced Primary Cooling)	Loss of Flow (Cond III)	DNBR (SAL*) ≥1.38	1.41
	Locked Rotor (Cond IV)	RCS Pres ≤ 3120 psia Rods-in-DNB ≤ 30%	2653 psia 25%
Overheating (Reduced Secondary Cooling)	Loss of Load (Cond II)	RCS Pres ≤ 2748.5 psia MSS Pres ≤ 1208.5 psia	2741.9 psia 1205.6 psia
	Loss of Feedwater (Cond II)	Przr Mix Vol ≤ 1000 ft^3	928 ft^3
	ATWS	RCS Pres ≤ 3215 psia	3175.1 psia
Overcooling	HFP MSLB (Cond III or IV)	DNBR (SAL*) ≥ 1.30 below 1st MVG	1.411
		DNBR (SAL*) ≥ 1.38 above 1st MVG	1.644
	HZP MSLB (Cond IV)	LHR ≤ 22.54 kW/ft	22.51 kW/ft
		DNBR (SAL*) ≥ 1.45 LHR ≤ 22.54 kW/ft	1.616 21.64 kW/ft

* Safety analysis limit DNBR has margin compared to the DNBR design limit
MVG = Mixing Vane Grid

NEXTera ENERGY POINT BEACH

Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
Reactivity Addition	Rod Withdrawal @ Power (Cond II)	DNBR (SAL*) ≥ 1.337 RCS Pres ≤ 2748.5 psia	1.337 2692 psia
	Rod Ejection (Cond IV)	Fuel Enthalpy ≤ 200 cal/g Fuel Melt (at hot spot) ≤ 10%	176.4 cal/g 9.8%

* Safety analysis limit DNBR has margin compared to the DNBR design limit

NEXTera ENERGY POINT BEACH

Large Break LOCA Analysis Performed Using NRC Approved Best Estimate ASTRUM with results meeting acceptance criteria

10 CFR 50.46 Requirement	Pre-ASTRUM/EPU Value	EPU Unit 1 Value	EPU Unit 2 Value	Acceptance Criteria
95/95 Peak Cladding Temperature (F)	2128	1975	1810	< 2200
95/95 Maximum Local Oxidation (%)	8.52	2.61	2.57	< 17.0
95/95 Core Wide Oxidation (%)	0.81	0.386	0.154	< 1.0
Coolable Geometry	Long term cooling is maintained via operator actions (discussed later). No impact on coolable geometry.			
Long-Term Cooling				

NEXTera ENERGY POINT BEACH

Small Break LOCA safety margin is assured by core design limit selection

Parameter	Pre - EPU		EPU	
Analyzed Core Power (MWt)	1683		1811	
Hot Channel Enthalpy Rise Factor [$F_{\Delta H}$]	1.80		1.68	
Maximum Relative Power in the Hot Assembly [P_{HA}]	1.667		1.62	
Axial Offset (%)	30		13	
Steam Generator Tube Plugging Level (%)	25		10	
Replacement Steam Generator Model	44F – Unit 1	Δ47 – Unit 2	44F – Unit 1	Δ47 – Unit 2

NEXTera ENERGY POINT BEACH

Small break LOCA analysis performed using NRC-approved NOTRUMP evaluation model demonstrated acceptable results

Parameter	Pre - EPU		EPU		Limit
	Unit 1	Unit 2	Unit 1	Unit 2	
Limiting Break Size	3-Inch		3-Inch		-
PCT (°F)	1205	1094	1049	1103	2200
Maximum Transient Local Oxidation (%)	0.03	0.02	0.01	0.02	17
Maximum Core-Wide Oxidation (%)	< 1	< 1	< 1	< 1	1

NEXTera ENERGY POINT BEACH

Safety system design assures long term post-LOCA considerations met

- **Emergency Core Cooling System (ECCS) Alignment**
  - Low pressure safety injection (LPSI) using the Residual Heat Removal (RHR) pumps aligns to the reactor vessel upper plenum provides upper plenum injection (UPI)
  - High head Safety Injection (SI) pumps align to the RCS cold legs
  - Plant design includes simultaneous injection – both SI and LPSI
    - -- Flushes the core for all break locations
    - -- Prevents boric acid precipitation
    - -- Assures long-term cooling
  - No interruption of ECCS flow to the core when moving from the injection to the recirculation phase

NEXTera ENERGY POINT BEACH

Analysis conservatisms and operator action timing margins ensure boric acid precipitation is precluded

- **Boric Acid Precipitation Large Break Scenario**
  - Rapid depressurization to enable LPSI injection flow
  - Mixing volume and void fraction calculated with Large Break LOCA code WCOBRA/TRAC – hot leg break
  - Credit for mixing with one-half lower plenum volume
  - Analysis conservatisms
    - -- No credit for mixing with UPI flow
    - -- No credit for beneficial effect of sump additives
    - -- No credit for containment pressure above atmospheric
    - -- No credit for entrainment
  - Time to reach boric acid solubility limit is 4 hours 50 minutes
    - -- Operators will restart cold leg recirculation within 3 hours 30 minutes, > 1 hour margin
    - -- Procedurally controlled and demonstrated on the simulator

NEXTera ENERGY POINT BEACH

Analysis conservatisms and operator action timing margins ensure boric acid precipitation is precluded

- **Boric Acid Precipitation Small Break Scenario**
  - Pressure remains above LPSI injection capability
  - Mixing volume and void fraction calculated with Small Break LOCA code NOTRUMP – Cold Leg Break
  - Credit for mixing with one-half lower plenum volume
  - Boric acid concentration calculated as a function of time
  - No credit for beneficial effect of sump additives or elevated containment pressure
  - Time to reach boric acid solubility limit is 7 hours
  - Operators will initiate cool-down within 1 hour and depressurize to enable LPSI flow (UPI) within 5 hours

NEXTera ENERGY POINT BEACH

Accident dose consequences meet acceptance limits

- **Alternative Source Term (AST) analyses performed at EPU power**
  - Key elements and assumptions used include:
    - -- Offsite and Control Room (CR) doses for FSAR chapter 14 events determined with AST methodology per Regulatory Guide 1.183
    - -- Control Room unfiltered in-leakage for limiting events was 200 cfm
    - -- LOCA dose considers ECCS recirculation to Primary Auxiliary Building (PAB) and Refueling Water Storage Tank (RWST)
  - Exclusion Area Boundary (EAB), Low-Population zone (LPZ), and CR doses are within the acceptance criteria of 10 CFR 50.67
  - AST analyses submitted separately

NEXTera ENERGY POINT BEACH

Steam generator tube rupture margin to overfill and dose analyses are conservative

- **Conservative dose calculation performed for AST with assumptions to bound EPU**
- **Margin to overfill analyzed**
  - Transient calculation utilized approved WCAP-10698-P-A method
  - Consistent with licensing basis
- **Results meet acceptance criteria**
  - Margin to overfill confirmed
  - AST doses bound operation at EPU power

NEXTera ENERGY POINT BEACH

Containment peak pressure remains within design limits during LOCA events

- **Method**
  - GOTHIC used for containment analysis
- **Results**
  - Peak containment pressure of 55.7 psig is less than design pressure of 60 psig
  - Calculated pressure of 9 psig at 24 hours is less than 50% of calculated peak pressure
  - Peak pressure increase of 1.9 psi from CLB

NEXTera ENERGY POINT BEACH

LOCA mass and energy (M&E) calculational model issues have minimal impact on containment integrity results

- **LOCA M&E calculational model issues include the EPITOME computer code**
- **Calculations were performed to address the impact of these issues on the Point Beach EPU**
- **Results**
  - Peak containment pressure of 55.7 psig is less than design pressure of 60 psig
  - Calculated pressure of 9 psig at 24 hours is less than 50% of calculated peak pressure
  - Peak pressure increase of 1.9 psi from CLB
  - Impact limited to first hour of event
- **All acceptance criteria for LOCA containment response continue to be met**

NEXTera ENERGY POINT BEACH

Containment peak pressure remains within design limit for main steam line break event

- **Methods**
  - LOFTRAN used for mass/energy release calculation
  - GOTHIC used for containment analysis
- **Plant Changes**
  - New fast-closing, safety-grade feedwater isolation valves and upgraded fast-closing back-up feedwater regulating valves
  - EPU analysis assumed high AFW flow rates that bound the AFW system modifications
- **Results**
  - Peak containment pressure of 58.7 psig is less than design pressure of 60 psig
  - Peak pressure reduction of 1.2 psi from CLB

NEXTera ENERGY POINT BEACH

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NEXTera ENERGY POINT BEACH

Models were updated accordingly to reflect the EPU conditions

- **Updated Full-Power Internal Events Models**
  - Logic models changed to reflect physical changes planned for EPU
  - Accident sequence changed to reflect new support system requirements
  - Human Reliability Analysis (HRA) updated to include EPU-related timing changes
- **External Events**
  - Assessed qualitatively
- **Shutdown Risk**
  - Assessed qualitatively

NEXTera ENERGY POINT BEACH

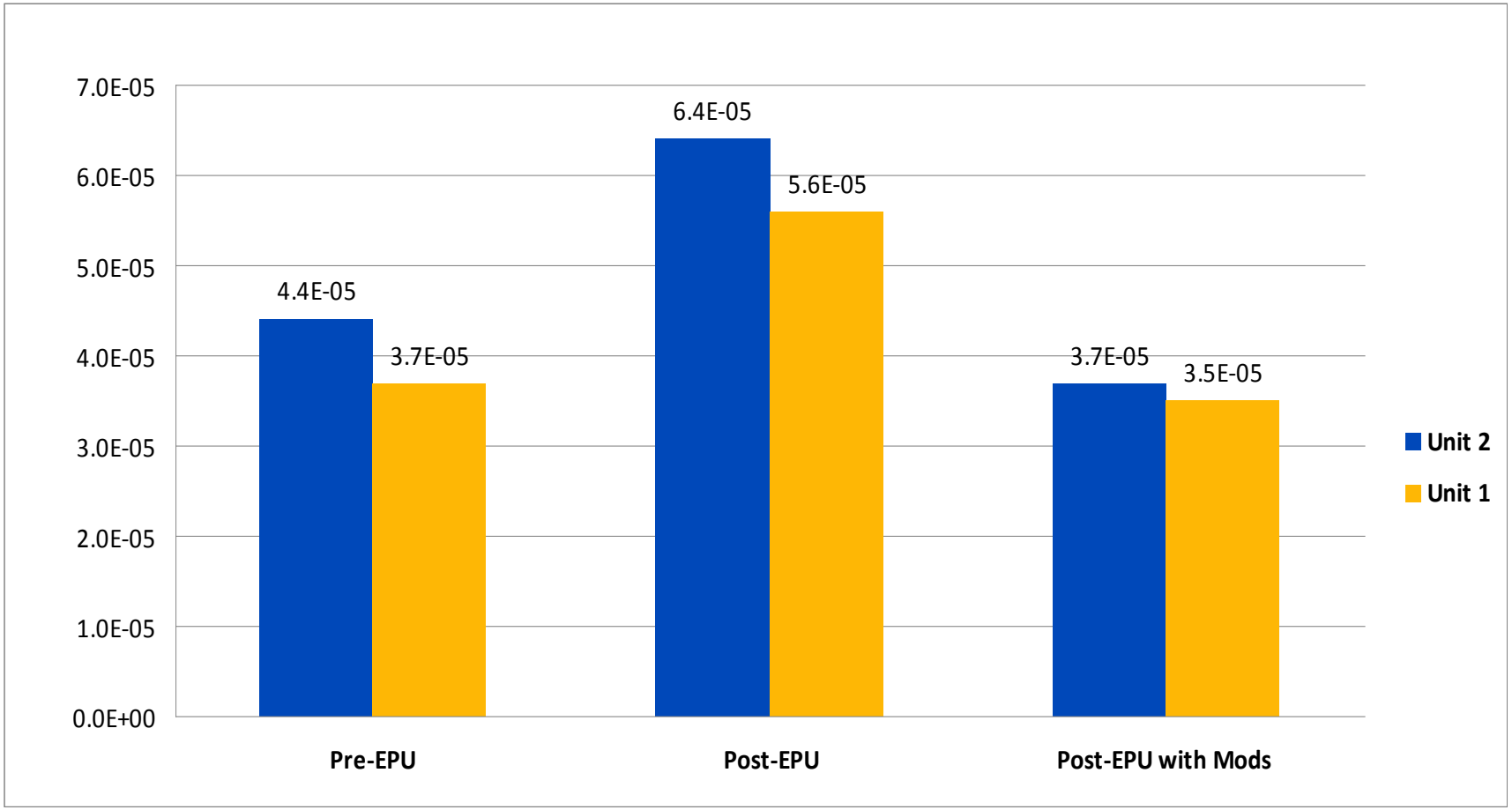
Overall the changes due to EPU resulted in a reduction to plant risks

- **Plant modifications were incorporated into the models**
- **Plant changes that resulted in a risk reduction**
  - AFW system changes
    - -- Increase backup air supply for AFW mini-recirculation valves
    - -- Auto switchover of AFW suction
    - -- Eliminated manual alignment of shared motor-driven AFW pumps
  - Provide self-cooled air compressor
  - Feedwater/Condensate system changes
  - Procedure change to improve reliability of RCS depressurization

NEXTera ENERGY POINT BEACH

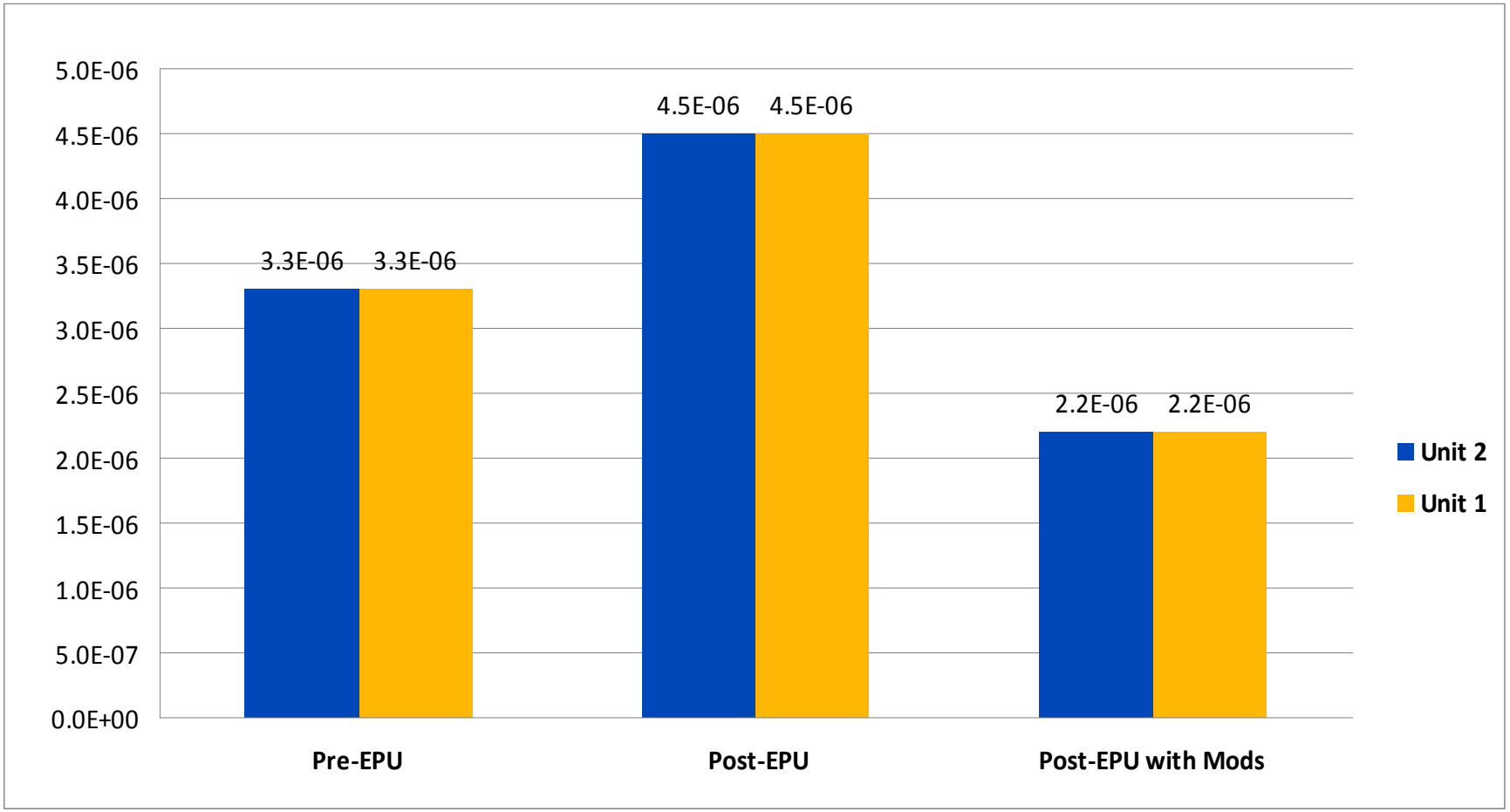
With the installed plant modifications, the Core Damage Frequency (CDF) decreases below the present value

EPU Impact on CDF



With the installed plant modifications, the Large Early Release Frequency (LERF) decreases below the present value

EPU Impact on LERF



Overall Risk is reduced following EPU

- **Overall Risk Is Reduced Following EPU**
  - Reduction in CDF
  - Significant reduction in LERF
  - Reduced dependence on Service Water
  - Improved Auxiliary Feedwater system design
  - Eliminated several of the risk significant operator actions

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NEXTera ENERGY POINT BEACH

Safety improvements include changes to improve the reliability of the Emergency Diesel Generators

- **Emergency Diesel Generators**
  - Capacity of the Emergency Diesel Generators (EDGs) is acceptable under EPU conditions
  - Addition of the new AFW pump motors and automatic start of control room emergency fans were evaluated
  - Time delay added to the motor-driven AFW pump start to improve EDG transient loading
  - Diesel generator load changes being made to reduce load to below 2000-hour rating
  - Proposed EPU Tech Spec Surveillance includes 24 Hour Endurance Test of each EDG every 18 months

Safety improvements ensure electrical distribution system reliability

- **New Main Generator output breakers**
- **4160V AC Distribution System**
  - Meet 4160V AC distribution equipment design ratings
  - Loss of voltage (LOV) relay time delay changes
    - -- Improves ability to maintain off-site power during transmission grid voltage transients
  - Protective relay settings impacted by EPU are revised to ensure protection and coordination
- **480V AC Distribution System**
  - Meet 480 V AC distribution equipment design ratings
- **Safety Related 120 V AC System**
  - Equipment ratings bound EPU operating conditions
- **Safety Related 125 V DC System**
  - Equipment ratings bound EPU operating conditions
  - Capability and capacity sufficient to supply EPU load changes

NEXTera ENERGY POINT BEACH

Environmental qualification of electrical equipment is maintained

- **Environmental Qualification**
  - Effects of EPU on the Environmental Qualification of electrical equipment evaluated
  - Equipment not qualified for EPU conditions are re-qualified or replaced

NEXTera ENERGY POINT BEACH

Actions will be implemented to ensure grid stability

- Impact of EPU evaluated by American Transmission Company (ATC), the grid system operator
- Actions needed by NextEra, Dominion and ATC identified and underway

NEXTera ENERGY POINT BEACH

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There has been significant Operations involvement and participation on the project

- **Resources**
  - Operations lead assigned full time to the EPU project in 2008
  - Additional licensed Senior Reactor Operators (SROs), Reactor Operators (ROs), and plant operators, and previously licensed SROs assigned in support roles
  - Operations provides input to modifications, licensing, testing, work orders, tagging, procedures, margin reviews
- **Human Factors**
  - Design guidelines followed for optimization of human factors for new controls
  - New motor-driven AFW controls located on control boards near Steam Generator indicators matching location of turbine-driven pump controls
  - Plant equipment locations considered for ease of access

NEXTera ENERGY POINT BEACH

There has been significant Operations involvement and participation on the project (continued)

- **Implementation**
  - Senior Operations personnel assigned as Startup Test Directors
  - Test organization reports to the Startup Test Directors
  - Startup Test Director works with Shift Manager, Operating crew, relief crew, and test organization to perform post-maintenance and power ascension testing

Simulator upgrades and procedure changes are being implemented to support the EPU

- **Simulator Modifications**
  - Unit 2 simulator modified prior to power uprate for AFW, AST and EPU modifications
  - Facilitated Emergency Operating Procedures (EOP) validations and Operator training
  - Unit 1 simulator to be modified prior to fall 2011 outage
- **Procedure Changes**
  - Emergency Operating Procedures (EOPs)
  - Emergency Contingency Action Procedures (ECA's)
  - Critical Safety Function Procedures (CSPs)
  - Abnormal Operating Procedures (AOPs)
  - Normal Operating Procedures (OPs)
  - Procedures were validated in simulator

NEXTera ENERGY POINT BEACH

On-going training since 2009 has been conducted to ensure the operators and other plant personnel are prepared for EPU

- **Training**
  - Operations classroom training in 2009, 2010 and 2011
  - Simulator training performed in first training cycle of 2011
  - Additional classroom and simulator training, and equipment walkdowns scheduled during outage
  - Just in Time Training will be performed for Operations and Test Engineers prior to startup testing
  - Maintenance and Technical training ongoing since 2009
  - Program training materials being updated

NEXTera ENERGY POINT BEACH

Some Operator response times and actions have changed, but are not considered to be a burden to the Operators

- **Operator Response Times**
  - Time to cold shutdown increases
  - Time to boil during shutdown decreases
  - New action to establish containment spray recirculation
  - New action to transfer from containment spray recirculation to cold leg recirculation
  - Removed action for operators to manually transfer AFW suction to service water
  - Improved capability to respond to certain secondary transients due to improved condensate and feedwater pumps

NEXTera ENERGY POINT BEACH

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NEXTera ENERGY POINT BEACH

A comprehensive test procedure has been developed to ensure testing is performed in a controlled, deliberate manner

- **Modeled after recent successful EPU Power Ascension programs**
  - PWR and BWR including Ginna, Kewaunee, Hope Creek, Vermont Yankee
- **Uprate Implementation Power Ascension Test Procedure will direct the overall sequence of power ascension**
- **Individual test procedures to demonstrate that structures, systems and components will perform satisfactorily at the EPU power level**
- **EPU Power Ascension**
  - Power is increased in a slow and deliberate manner
  - Stopping at pre-determined power levels for steady state data gathering and formal parameter evaluation
  - Data evaluated to pre-established acceptance criteria

NEXTera ENERGY POINT BEACH

A comprehensive test procedure has been developed to ensure testing is performed in a controlled, deliberate manner (continued)

- **Post-modification testing and power ascension testing will demonstrate performance of plant controls and enhanced control upgrades will continue to operate reliably at EPU conditions**
- **No large transient testing will be performed**
  - EPU changes primarily involve replacement of existing equipment with more reliable equipment with no significant changes to how the integrated controls systems respond to plant transients
  - LOFTRAN code has been verified against data from several plant transients, and showed good agreement between the LOFTRAN results and the plant transients
  - LOFTRAN was used to simulate Point Beach large load reduction transient and LOFTRAN demonstrated acceptable plant behavior

EPU Power Ascension test program will ensure plant systems and equipment affected by EPU respond as expected and within limits

- **EPU Power Ascension Test Program verifies the following:**
  - Plant systems and equipment affected by EPU are operating within design limits
  - Nuclear fuel thermal limits are maintained within expected margins and the core is operating as designed
  - Steam Generator water level control is stable with adequate control margin to allow for anticipated transients
  - Reactor control systems are stable and capable of maintaining reactor parameters within acceptable limits
  - Moisture Separator Reheater (MSR) and feedwater heater drains and level control are stable
  - System radiation levels are acceptable and stable
  - General area and local environmental conditions are acceptable

NEXTera ENERGY POINT BEACH

A special start-up test organization has been established to ensure proper support and management oversight

- Start-up test organization reports to Plant General Manager
- Senior Operations personnel assigned as Startup Test Directors
- Multi-disciplined testing organization – Engineering, Operations, Chemistry, Radiation Protection, Maintenance
- Test Review Board and Plant Operations Review Committee/Plant General Manager approvals
- Power Ascension Test Procedure is classified as an Infrequently Performed Test and Evolution (IPTE) with senior management oversight

NEXTera ENERGY POINT BEACH

Additional surveillance and monitoring is conducted to ensure the plant response does not result in an unanticipated transient condition

- **The following additional surveillance and monitoring will be performed during power ascension:**
  - A Steam Generator (SG) level deviation test will be performed at selected power levels
  - Feedwater Heater level controls are tested by deviating the Feedwater Heater level and the placing the control system back in automatic control
  - The Feedwater (FW) pumps, Condensate System (CS) pumps and (HD) Heater Drain pumps will be tested to ensure the system interactions are performing as expected
  - Power System Stabilizer and Voltage Regulator response testing

NEXTera ENERGY POINT BEACH

Power ascension will be conducted using the normal operating procedures with established hold points

- **Station Uprate Implementation Power Ascension Test Procedure**
  - Normal operating procedures will be used to maneuver the plant
  - Power Ascension Test Procedure coordinates hold points required during power escalation and directs individual testing activities and data acquisition
  - System monitoring plans developed for systems both directly and not directly impacted by EPU
  - If unexpected plant conditions occur, the test will be stopped and power reduced to the last acceptable operating configuration or as directed by plant procedures
  - Test Review Board function is to review and approve of test results at all power plateaus
  - Management approval at selected power plateaus

NEXTera ENERGY POINT BEACH

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NEXTera ENERGY POINT BEACH

Acronyms

AC	Alternating Current
AE	Architect-Engineer
AFW	Auxiliary Feedwater
AOP	Abnormal Operating Procedure
ASME	American Society of Mechanical Engineers
AST	Alternative Source Term
ATC	American Transmission Company
BMI	Bottom Mounted Instrument
BOP	Balance of Plant
BWR	Boiling Water Reactor
CAOC	Constant Axial Offset Control
CDF	Core Damage Frequency
CLB	Current Licensing Basis
COLR	Core Operating Limits Report
CR	Control Room
CREFS	Control Room Emergency Filtration System
CS	Condensate System
CSP	Critical Safety Function Procedures
CST	Condensate Storage Tank
Cv	Flow Coefficient
DBA	Design Basis Accident
DNB	Departure From Nucleate Boiling
DNBR	Departure From Nucleate Boiling Ratio
EAB	Exclusion Area Boundary
ECA	Emergency Contingency Action Procedures
ECCS	Emergency Core Cooling System

EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EPPY	Effective Full Power Year
EPU	Extended Power Uprate
EQ	Environmental Qualification
ERG	Emergency Response Guidelines
ESFAS	Engineered Safety Features Actuation System
FAC	Flow Accelerated Corrosion
FERC	Federal Energy Regulatory Commission
FQ	Total Peaking Factor
FW	Feedwater
FΔH	Hot Channel Enthalpy Rise Factor
HD	Heater Drain
HELB	High Energy Line Break
HRA	Human Reliability Analysis
ILT	Initial License Training
IPTE	Infrequently Performed Tests and Evolutions
JITT	Just In Time Training
kV	Kilovolts
LAR	License Amendment Request
LBLOCA	Large Break Loss of Coolant Accident
LERF	Large Early Release Frequency
LHR	Linear Heat Rate
LOAC	Loss of AC
LOCA	Loss of Coolant Accident
LONF	Loss of Normal Feed

NEXTera ENERGY POINT BEACH

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

ACRS Subcommittee on Power Uprates

NRC Staff Review
Point Beach Units 1 and 2
Extended Power Uprate

February 24, 2011

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Opening Remarks

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U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Opening Remarks

- NRC staff effort
  - Requests for additional information
  - Supplements to application
- Challenging review areas
  - AST and AFW amendment s
  - High energy line break (HELB) methodology
  - Margin-to-overfill and boron precipitation analyses

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Introduction

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Office of Nuclear Reactor Regulation

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Background

- Application

- Submitted on April 7, 2009
- Licensing Report
- Auxiliary Feedwater Modification
- HELB Methodology
- RPS/ESFAS Setpoint Methodology
- Total of 12 supplements to the application

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Topics for February 24

- EPU Overview
- Fuel and Core
- Safety Analyses
- Materials and Chemical Engineering
- Source Term and Radiological Consequences

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Point Beach Units 1 and 2 Extended Power Uprate ACRS Subcommittee Meeting

Safety Analysis

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Agenda

- Review Procedures
- General Results
- Challenging Review Areas
- Conclusions

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Review Procedures

- Follow Review Standard 001
- Ensure that analytic methods are used consistent with their approval
- Compare results to similar plants
- Apply additional effort to challenging review areas (steam line break, boric acid precipitation, steam generator tube rupture):
  - Multiple rounds of RAIs
  - Independent calculations
  - Audits and site visits

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General Results

- Most results acceptable
  - Analysis performed using NRC-approved methodology
  - Results acceptable with margin to acceptance criterion or regulatory limit
- Some events outside Point Beach design basis
  - Licensee provided a description of expected sequence of events
  - Staff compared to existing plant to determine whether not analyzing the event presented a safety concern
- Three events required more detailed evaluation
  - Steam line break, boric acid precipitation, steam generator tube rupture

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Challenging Review Areas

- Main Steam Line Break
- Steam Generator Tube Rupture
- Post-LOCA Boric Acid Precipitation

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Main Steam Line Break

- Steamline Break Topical Report does not apply to two-loop plants
- Results are deemed acceptable without reference to the Steamline Break Topical Report

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Main Steam Line Break

Steamline Break Topical Report was written in 1978, when . . .

- Plants had BITs (20,000 ppm B)
- Credible breaks did not return to critical
- Largest steamline break size was always the most severe case

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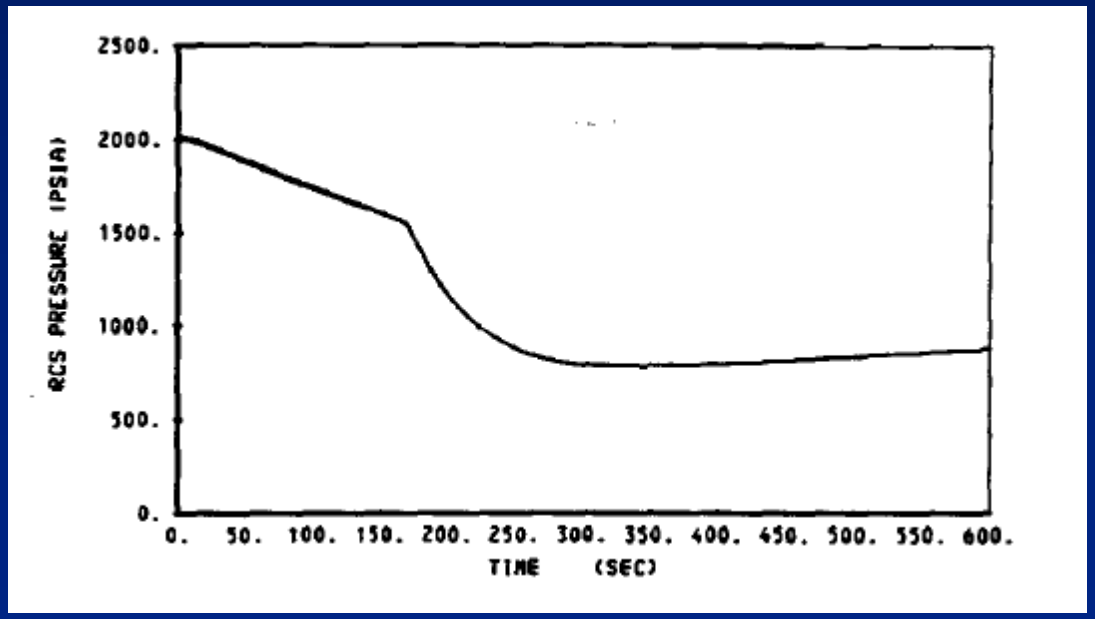
Steamline Break

Credible breaks

- Do not lead to steamline isolation
- Do not actuate SI from low steamline pressure
- Are not self-limiting
- Do not lead to accumulator injection

Steamline Break

- Point Beach credible break (1990)
- Accumulator injection setpoint is 700 psia



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Post-LOCA Boric Acid Precipitation

- Point Beach ECCS Design
  - Two-loop reactor coolant system
  - 695 psia accumulators
  - Low-pressure upper plenum injection
  - High head safety injection
    - Terminated upon drainage of RWST
  - High concentration boric acid makeup tank
- Hot leg break limiting for precipitation
  - LPSI and HHSI during injection mode provides flushing for first 20 minutes
  - HHSI secured at 20 minutes (recirculation mode)
    - Boric acid buildup begins

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Control of Boric Acid

- Large Breaks
  - Reinitiate HHSI prior to precipitation
- Small Breaks
  - Cooldown RCS to low-pressure cut in
    - 135 psia, *or*
  - Refill RCS with emergency core cooling
    - Re-establishes single phase natural circulation

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Model Assumptions (NRC Staff and Licensee)

- Mixing volume:
  - Half of lower plenum
  - Core
  - Upper plenum below hot leg
- 1971 ANS Decay Heat Standard + 20%
- Mixing volume is time-dependent
- RWST and SIT concentrations 3200ppm

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Review Results

- Precipitation timing:
  - 4 hours 50 minutes (licensee)
  - 4 hours 25 minutes (staff)
- Licensee must initiate HHSI before precipitation is predicted to occur
  - Licensee modified the timing requirement to 3 hr 20 minutes
    - Originally was 4 hours 20 minutes – 4 ½ hour effective flush time
    - Staff was concerned about insufficient safety margin
  - Licensee agreed to terminate flow from BAST during LOCA (If not, causes a two hour precipitation time)
  - Flushing flow can be initiated in 10 minutes
    - Licensee confirmed 10 minute operator action time
    - Testing as part of operator training and qualification program
- Staff RELAP5 calculations confirmed non-limiting nature of SBLOCA

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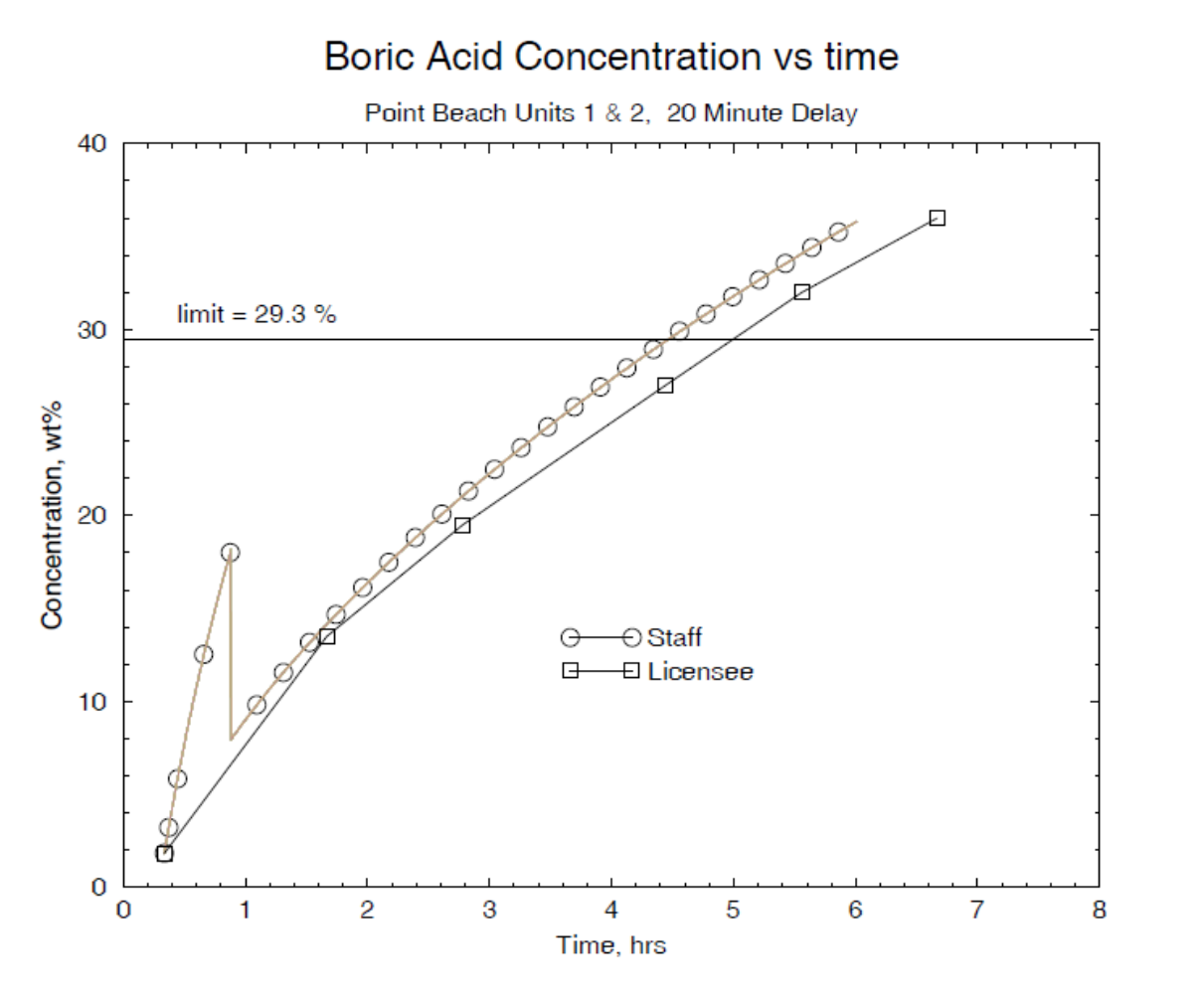

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Conclusions

- Staff analysis confirmed
  - Non-limiting nature of SBLOCA (RELAP5)
  - Timing for boric acid precipitation
- Staff identified concerns with timing for boric acid precipitation control
  - Licensee revised boric acid precipitation control approach to satisfy staff concerns
    - Terminate boric acid storage tank flow
    - Initiate flushing flow earlier
- Staff finds LOCA calculations acceptable

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Steam Generator Tube Rupture

- Beyond the Point Beach design basis
- No explicit regulatory acceptance criteria
- Radiological consequences -10 CFR 50.67
  - What is a reasonable assessment of radiological consequences?

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Licensee's Analytic Approach

- Hand-calculation for radiological consequences
  - Constant, conservative post-trip break flow flashing fraction
  - No operator intervention for 30 minutes
  - Break flow terminated in 30 minutes
  - Steam generator does not overfill with water
- Two LOFTTR-2 analyses demonstrate that hand-calculation is conservative
  - Extended blowdown mass release analysis demonstrates that hand-calculation provides a conservative prediction of the atmospheric steam release
  - Margin to Overfill (MTO) analysis demonstrates that the steam generator won't overfill with water

- MTO wasn't performed using NRC-accepted analytic methodology

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Additional Review – Margin to Liquid Overfill

- Licensee repeated MTO calculations but did not include a limiting single failure
  - More consistent with NRC-accepted method
- Staff reviewed defense-in-depth mechanisms to determine that excluding single failure was reasonable
  - Instrument air to open atmospheric dump valve will most likely be available; can be restored if lost

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SGTR - Conclusions

- Hand-calculation is conservative
  - Radiological consequences bound other analyses by factor of two
- MTO does not follow approved guidance but is reasonable
- EPU would not exacerbate the SGTR accident conditions

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Reactor Systems Review Conclusions

- Review followed RS-001
- Staff independently assessed EPU
  - Additional engineering evaluations
  - Independent calculations
  - Site visit and desk audit
- Staff finds EPU acceptable with respect to safety analysis

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QUESTIONS

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Materials and Chemical Engineering

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PROTECTIVE COATING SYSTEMS

- Original containment coatings predate Regulatory Guide 1.54 and ANSI 101.4
- Coatings were accepted based on testing and an evaluation contained in the Final Safety Analysis Report, Section 5.6.2.4
- Containment temperature, pressure, pH, and radiation dose at EPU accident conditions remain bounded by original acceptance test conditions

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FLOW ACCELERATED CORROSION (FAC)

- FAC program remains consistent with industry guidelines after EPU
  - EPRI Report NSAC-202L-R3

- CHECWORKS model to be updated prior to EPU
  - Increases and decreases in corrosion rates predicted
  - Decreases verified with examinations
  - Increases put in the model

- Scope of FAC program not changing as a result of EPU

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STEAM GENERATOR TUBE INTEGRITY

- SG inspection program, based on NEI 97-06, "SG Program Guidelines," will continue to manage degradation effectively at EPU conditions

- Unit 1 – Alloy 600 Thermally Treated Tubes
- Unit 2 – Alloy 690 Thermally Treated Tubes
- SG design and operational parameters bound EPU conditions

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STEAM GENERATOR BLOWDOWN SYSTEM

- Point Beach Nuclear Plant (PBNP) licensed prior to approval of the GDC in Appendix A of 10 CFR 50
- PBNP GDC 9 is the equivalent of GDC 14
- Original SG design and operational parameters bound EPU conditions
- Blowdown flowrate not affected by EPU conditions
- FAC of SGBS components continues to be monitored by the FAC program

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CHEMICAL AND VOLUME CONTROL SYSTEM

- PBNP GDC 9 and 27 are equivalent of 10 CFR 50 Appendix A GDC 14 and 29
- At EPU conditions:
  - Increased boration requirement
  - Potential for increased crud buildup
- Changes in letdown, charging, and makeup are bounded by current system capabilities
- CVCS not used for high-pressure injection

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Summary

➢ The following review areas were found to be acceptable at EPU conditions:

- Protective Coatings Systems
- Flow Accelerated Corrosion
- Steam Generator Tube Integrity
- Steam Generator Blowdown System
- Chemical and Volume Control System

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Source Terms and Radiological Consequences Analyses

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Source Terms

- Review conducted in accordance with Matrix 9, Section 2.9.1 of the Review Standard for Extended Power Uprates (RS-001)
- Radiation sources in reactor coolant and steam analyzed for EPU conditions
- Review considered source terms associated with normal operations and for accident conditions

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Radwaste Systems Analysis

- Gaseous waste sources and liquid waste sources
- Evaluated based on source terms for normal operations and anticipated operational occurrences

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Radwaste Systems Analysis Summary

- Licensee has adequately accounted for the effects of the proposed EPU
- Licensee has adequately characterized the source terms at the proposed EPU
- All liquid and gaseous effluents will meet the requirements in 10 CFR Part 20
- Continue to meet requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and GDC-60

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DBA Radiological Consequences Analyses

- Review conducted in accordance with Matrix 9, Section 2.9.2 of RS-001
- On December 8, 2008, the licensee submitted an application to implement a full-scope Alternate Source Term (AST) per 10 CFR 50.67.

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DBA Radiological Consequences Analyses

- This AST amendment evaluated DBAs based on the proposed EPU power level of 1811 MWt
- DBAs in the AST evaluated in accordance with 10 CFR 50.67 and SRP 15.0.1 dose acceptance criteria both offsite and in the control room

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DBA Radiological Consequences Analyses

- Point Beach EPU amendment request included a reanalysis of accidental waste gas releases for the proposed EPU power level of 1811 MWt

- Waste gas release events evaluated in accordance with 10 CFR Part 20 and GDC-19.

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DBA Dose Analyses in AST and EPU Submittals

- Review conducted in accordance with guidance in RG 1.183

- DBAs Evaluated:
  - LOCA
  - SGTR
  - LRA
  - MSLB
  - CRDE
  - FHA
  - RVHD
  - Waste Gas Release Events (GDT, VCT, CDT)

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Radiological Consequences Analyses Conclusion

- Licensee has adequately accounted for the effects of the proposed EPU.
- All DBAs evaluated for the AST meet 10 CFR 50.67 and SRP 15.0.1 dose acceptance criteria both offsite and in the control room.

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Radiological Consequences Analyses Conclusion

- The radwaste release events evaluated for the EPU meet 10 CFR Part 20 and GDC-19
- The staff finds the proposed EPU acceptable with respect to the radiological consequences of DBAs.

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Public Comments

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Committee Comments

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Adjourn