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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

March 15, 2006

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This transcript has not been reviewed, corrected and edited and it may contain inaccuracies.

1 UNITED STATES OF AMERICA

2 NUCLEAR REGULATORY COMMISSION

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4 ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

5 MEETING OF THE SUBCOMMITTEE ON POWER UPRATES

6 + + + + +

7 WEDNESDAY,

8 MARCH 15, 2006

9 + + + + +

10 The meeting was convened in

11 Cabinet/Judiciary Suite of the Hyatt Regency Hotel,

12 Bethesda, Maryland, at 8:30 a.m., Dr. Richard Denning,

13 Subcommittee Chairman, presiding.

14 MEMBERS PRESENT:

15 RICHARD S. DENNING, Chairman

16 JOHN SIEBER

17 GRAHAM B. WALLIS

18 OTTO L. MAYNARD

19 ACRS STAFF PRESENT:

20 RALPH CARUSO

21 SAM MIRANDA

22

23

24

25

1 NRC STAFF PRESENT:

2 PATRICK MILANO

3 JOHN NAKOSKI

4 KENT WOOD

5 BRIAN LEE

6 CHRIS McHUGH

7 NEIL RAY

8 JOHN WU

9 RAUL HERNANDEZ

10 ALSO PRESENT:

11 MARK FLAHERTY	Constellation Power
12 MARK FINLEY	Constellation Power
13 JIM DUNNE	Constellation Power
14 ROY GILLOW	Constellation Power
15 DAVE WILSON	Constellation Power
16 GORDON VERDIN	Constellation Power
17 JEFF KOBELAK	Constellation Power
18 JOE PACHER	Constellation Power
19 GEORGE WROBEL	Constellation Power

20

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A-G-E-N-D-A

1 P-R-O-C-E-E-D-I-N-G-S

2 8:30 a.m.

3 CHAIRMAN DENNING: The meeting will co me

4 to order. This is the Advisory Committee on Reactor

5 Safeguards Subcommittee ion Power Rates. I am Rich

6 Denning, Chairman of the Subcommittee.

7 The Subcommittee members in attendance are

8 Otta Maynard, Jack Sieber and Graham Wallis.

9 The purpose of this meeting is to discuss

10 the extended power uprate application for the Ginna

11 Nuclear Power Plant. The Subcommittee will hear

12 presentations by and hold discussions with

13 representatives of the NRC Staff and the Ginna

14 licensee Constellation Energy regarding these matters.

15 The Subcommittee will gather information,

16 analyze relevant issues and facts and formulate

17 proposed positions and actions as appropriate for

18 deliberation by the full Committee.

19 Ralph Caruso is the designate federal

20 official for this meeting.

21 The rules for participation in today's

22 meeting have been announced as part of a notice of

23 this meeting previously published in the *Federal*

24 *Register* on March 3, 2006.

25 A transcript of the meeting is being kept

1 and will be made available as stated in the *Federal*
2 *Register* notice.
3 It is requested that speakers first
4 identify themselves and speak with sufficient clarity
5 and volume that they can be readily heard. We have a
6 very limited number of microphones in the room here,
7 so that's going to be a little painful. But please
8 make sure you go to a microphone when you make a
9 statement.
10 \ We have not received any requests for
11 members of the public to make oral statements or
12 written comments.
13 Review of an application for a power
14 uprate is one of the most challenging activities that
15 the NRC undertakes. Based on source term alone we
16 know that the risk will increase by at least 17
17 percent due to this application. But the subtle
18 change in risk is associated with decreased in safety
19 margins. We have to look carefully at those margins,
20 the uncertainties and determine whether the increment
21 to safety limits are still adequate.
22 Let me first say what we don't want to
23 hear today. We don't want to hear a checklist of areas
24 of reviews where the change in plants conditions is
25 negligible and the safety of the plant is unaffected.

1 If you have any viewgraphs of that type, tell us why
2 you're going to jump over them and move on.
3 What we do want to hear about today are
4 the results of quantitative analyses. We want to see
5 changes in margins, the effect of uncertainties. If
6 you present sensitivity studies, we want to know what
7 the basis was for the range selected for those
8 sensitivity studies. We want to hear about processes
9 that would be affected by changes in conditions such
10 as vibrations in equipment, flow accelerated
11 corrosion. And we also want to hear about the
12 programs that will identify approached on safe
13 conditions.
14 Now, as I've looked at the agenda I think
15 that it is appropriate and that we will focus on the
16 important things that we do want to review.
17 We will now proceed with the meeting and
18 I call up Mr. Milani of the NRC Staff to begin.
19 MR. MILANO: Good morning. All right.
20 Again, my name is Pat Milano. I'm the
21 Senior Project Manager in NRR for the Ginna and
22 Calvert Cliff Stations.
23 Before I get started here, I'd like to
24 give a little bit of background for the application.
25 The application came in on July the 7th of 2005 and

1 subsequent there have been a series of supplement to
2 that ranging from last August through now.
3 The application itself was provided to us
4 in two specific parts; basically the overview with the
5 technical specifications that are going to be changed
6 and then the licensee's analysis presented in terms of
7 what we call a licensing report.
8 The presentations today are going to be
9 focused on several topics. One is the fuel and core
10 design, which will be presented by the licensee,
11 followed by safety analysis focusing both on the
12 reactor systems areas an dose consequence. And then a
13 presentation on risk.
14 You'll notice here there's a slight change
15 to the agenda. We're going to talk about electrical
16 impacts, predominately grid and power delivery. The
17 licensee's member has a conflict tomorrow, so we had
18 to move this one up earlier.
19 And then as you see here the remainder of
20 the afternoon will be mechanical matters, reactor
21 vessels, the various degradation mechanisms and then
22 we'll talk about some of the mechanical systems,
23 predominately in the balance of plant.
24 Tomorrow will be limited. We'll be
25 talking about operations and testing, human factors

1 issues.

2 MEMBER WALLIS: Can I ask that when we get
3 these presentations we hear where we are today and
4 what the effect of the uprate will be. The safety
5 evaluation report simply seemed to say they meet all
6 the requirements. But I like to know the value of
7 some parameter is something today, this uprate will
8 change it by this much and here's the limit. And I did
9 not see that. And maybe this is all going to happen,
10 but that's what I'd like to see. I'd like to know what
11 the change is and how close we are to limits in every
12 one of these categories that's important.

13 MR. MILANO: The application, the July 7th
14 application came in after several preapplication
15 submittals. There were three amendments that came in
16 in late April. One for relaxed axial offset control,
17 one for main feedwater isolation valves and one for
18 revised LOCA analyses methodologies. Of these three,
19 three constrain the approval or the Staff's approval
20 of the power uprate. The power uprate itself assumes
21 that these three amendments have been previously
22 approved. And just for a quick status, the axial
23 offset control was approved on February 14th. Main
24 feedwater isolation valves has the Staff review and
25 along with the OGC review had been completed and it's

1 in the final stages of administrative processing with
2 the expectation of issuance by the end of the week.
3 The revised LOCA analysis continuing to be reviewed by
4 the Staff.
5 The Staff's schedule basically centers on
6 the licensee's need date for implementation. The
7 licensee plans to implement the power uprate --
8 MEMBER WALLIS: Excuse me. Revised LOCA
9 analysis; is that because it's now being done a
10 different way?
11 MR. MILANO: Yes.
12 MEMBER WALLIS: Is there going to be a
13 comparison with the old way or are we just going to
14 see the new way?
15 MR. MILANO: No. There will be no
16 comparison with the old way.
17 MEMBER WALLIS: Presumably they're
18 choosing the new way because it's favorable to do it
19 that way?
20 MR. MILANO: Yes.
21 MEMBER WALLIS: So it might be interesting
22 to see what would have happened if they did it the old
23 way? But we won't see that?
24 MR. MILANO: No, you will not.
25 MEMBER WALLIS: Okay.

1 MR. MILANO: Okay. As I indicated, the
2 schedule is constrained by the licensee's requested
3 implementation during the fall 2006 refueling outage.
4 Right now the Staff's schedule -- excuse me. The draft
5 safety evaluation has been issued with the exception
6 of the open item, although in the LOCA analysis area
7 the Staff has completed its review of the large break
8 and the non-LOCA transients. However, the Staff
9 continues to review a combination of issues centered
10 around small break LOCAs, long term cooling and boron
11 precipitation. The expectation is for the Staff to
12 complete its review of those areas on or before April
13 4th. That portion of the safety evaluation will be
14 provided to the ACRS in order to meet the next
15 Subcommittee meeting late in April wherein those
16 issues itself will be talked about after the Beaver
17 Valley Subcommittee meeting. And then followed on
18 with the May 4th full Committee meeting.
19 Based on that, the Staff's goal is to
20 issue the safety evaluation in the July or early
21 August time frame.
22 With that, that concluded my presentation
23 with regard to the introduction. Baring any
24 questions, I'm going to turn it over to the licensee
25 for their introduction.

1 MR. FLAHERTY: My name is Mark Flaherty.
2 I'm the Acting Vice President of Nuclear Technical
3 Services with Constellation Generation. I'm out of
4 the corporate offices in Annapolis, Maryland.
5 Previous to that I was at Ginna Station
6 for approximately 15 years where I received my SRO
7 cert and was an STA for approximately one year and
8 held management positions in engineering, licensing
9 and PRA.
10 So we're glad to be here to have this
11 opportunity to talk to ACRS about the proposed uprate.
12 I'll start off with a high level overview
13 introduction. And I'll be followed by Mark Finely,
14 who will discuss the plant changes. Mark was the
15 project manager for this with Constellation. He'll be
16 followed by Dave Wilson who will go over the process
17 focusing on the licensing issues. And then followed
18 by Gordon Verdin who will discuss the fuel and core.
19 And then also Mark Finley will come back and discuss
20 safety analysis. Rob Cavedo will discuss risk
21 evaluation. Jim Dunne will discuss mechanical impacts.
22 Joe Pacher will discuss electrical impacts. Roy
23 Gillow will discuss operations and testing. And then
24 I'll conclude tomorrow morning.
25 With respect to the introduction, I'm

1 going to discuss a little bit about the design and
2 operating history for Ginna, some initial preparations
3 that were done for the uprate prior to initiation of
4 this project. And also some of the executive
5 oversight that was done both from the site perspective
6 and from Constellation Corp's perspective.
7 With respect to the history of Ginna,
8 Ginna is a Westinghouse two loop 1520 megawatt thermal
9 intercourse design. Went commercial operation in
10 1970. And the original license power level was for
11 1300 megawatts thermal. In 1972 it was uprated to
12 1520 megawatts thermal consistent with its sister
13 plants Kewaunee, Point Beach and Prairie Island.
14 The uprate that we're proposing and
15 discussing today brings us up to 1775 megawatts
16 thermal, which is very consistent with the current
17 operating level of Kewaunee, one of the Ginna sister
18 plants.
19 MEMBER WALLIS: Are you going to tell us
20 why it's 1775 and not 1800 or some bigger number? Is
21 there some limiting phenomenon which determines that
22 it should be 1775?
23 MR. FLAHERTY: Yes. Mark Finely will
24 address that in the next --
25 MEMBER WALLIS: So there is one particular

1 phenomenon that limits? What is it? Or is it a whole
2 bunch of phenomenon?
3 MR. FINLEY: Well, we'll get to that.
4 MEMBER WALLIS: You will explain that?
5 MR. FLAHERTY: Yes.
6 MR. FINLEY: In the safety analysis
7 section.
8 MEMBER WALLIS: Because it wasn't clear to
9 me where you were limited. And you're going to tell
10 us that clearly?
11 MR. FINLEY: Yes.
12 MEMBER WALLIS: Okay. Thank you.
13 MR. FLAHERTY: Prior to pursuing the
14 uprate project for Ginna Station, some activities
15 occurred at Ginna that did set the stage for allowing
16 us to go for uprate. This included in 1996 we did
17 replace the steam generators at Ginna. And the
18 replacement steam generators were sized sufficiently
19 to provide the opportunity to pursue uprate when the
20 company desired to pursue that.
21 Also in 2003 we did replace the reactor
22 vessel head for Ginna Station.
23 With respect to the team itself, we
24 elected to pursue a very experienced project team that
25 included Westinghouse, Stone & Webster and Siemens.

1 And many of those individuals are here in this room
2 also.
3 We also provided a lot of executive
4 oversight. This is both from a standpoint from a
5 corporate perspective and also from a vendor
6 perspective and industry experts with the intention
7 being that we wanted to use as much operating
8 experience as was available out there for people that
9 had pursued uprates and to bring that to the team to
10 make sure that those were addressed up front and
11 throughout the project.
12 As far as the executive oversight,
13 Constellation senior management was closely involved.
14 This includes both site management, the site Vice
15 President and plant General Manager and those
16 individuals, and also from a corporate perspective
17 from within Annapolis.
18 We formed an Executive Oversight
19 Committee, and that has met eight times to date. And,
20 actually, we have another meeting scheduled for next
21 week.
22 And the purpose of the Executive Oversight
23 was it looks at all the various aspects of the project
24 both from safety analysis and technical items that
25 we're discussing today, but also from the standpoint

1 of how do we implement these items from outage
2 management, that type of thing.
3 The Executive Oversight included a lot of
4 experience, former NRC management and industry
5 management experts. And they were actively engaged. To
6 a certain extent you can almost correlate this to like
7 an NSRB, Nuclear Safety Review Board concept for this
8 project.
9 And we also ensured from a Constellation
10 management perspective, we wanted to make sure that
11 all resources were available. And you'll hear a lot of
12 discussion today about some of the risk beneficial
13 changes that were being made that when we pursued this
14 project we wanted to ensure that we weren't just
15 pursuing it in order to obtain additional megawatts,
16 but we also focused on what's the impact of this
17 uprate on operations and that type of thing and could
18 we also pursue some beneficial actions at the same
19 time we were operating to reduce potential burden on
20 the operators. And those will be discussed today.
21 CHAIRMAN DENNING: Okay. And you'll
22 specifically identify those risk beneficial changes
23 for us, and are they all in the procedural domain?
24 MR. FLAHERTY: No.
25 CHAIRMAN DENNING: Okay.

1 MR. FLAHERTY: And I think Rob will go
2 into more detail specifically in the risk deltas and
3 improvements and that type of thing.
4 So with that, I'll turn this over to Mark
5 Finley then.
6 MR. FINLEY: Good morning. As Mark said,
7 my name is Mark Finley. I'm the Project Director for
8 the power uprate at Ginna.
9 In terms of my background, 28 years
10 nuclear power, 7 years additionally in nuclear Navy.
11 And then 19 years at Calvert Cliffs. And then the
12 last two years I've been at Ginna as the Project
13 Director for this power uprate.
14 Significantly, at Calvert Cliffs the last
15 13 years there I was in the fuel and safety analysis
16 group, which is why I'll be talking about the safety
17 analysis here the next time I come up.
18 What I'm going to do at this point is
19 discuss the changes to operating parameters, the
20 modifications to the plant to achieve the power
21 uprate, the license amendments and the use of
22 operating experience that has gone into the design and
23 procedure updates for the plant.
24 Before I begin, though, I would like to
25 echo the comments that Mark made about our experienced

1 project team and specifically about the Ginna
2 engineers that you're going to hear later today.
3 These Ginna engineers all have significant experience
4 at the Ginna site, perhaps with the one exception Rob
5 Cavedo who is a corporate PRA specialist. But the
6 other engineers are the lead engineers in their
7 technical areas at Ginna which means not only were
8 they familiar with the design and licensing basis for
9 Ginna, but they're also very familiar with the
10 operational issues and the real margin issues at
11 Ginna. And these are the engineers that were the lead
12 people on my project team.
13 One of the lessons incorporated in our
14 project team was not to come in with a corporate
15 project team that really had no experience at the
16 site. We did not do that from the beginning.
17 And these gentlemen from Ginna, of course,
18 are backed up by very experienced teams at
19 Westinghouse, at Stone & Webster. And we've got a
20 selection of those experts here today. And we're
21 going to try to give you a meaty presentation. If we
22 don't have the meat that you're looking for, ask the
23 question and we'll try to get you the answer.
24 The first slide here I'm going to call my
25 Waterford legacy slide. Because I looked at the

1 transcript of your meeting with Waterford and I saw
2 confusion about how exactly is the plant going to get
3 the power out. And I hope to do that with this slide.
4 If I don't, then please ask questions.
5 It's a little bit busy, but I'll spend
6 some time with it.
7 But first of all, the first line item
8 there core power. You see the change from 1520 to 1775
9 megawatt thermal. That is a 16.8 percent increase.
10 So you ask how do we get that power out?
11 Really two major changes. The first is the average
12 coolant temperature is increasing, that second line
13 item. The average temperature coolant is increasing
14 from 561 degrees to 574 degrees. And we do that to
15 raise the steam pressure in the steam generator and
16 drive the flow through the turbine. Okay. That's the
17 first change.
18 The second primary change we're using to
19 increase the power out of the plant is the ΔT or delta
20 h across the core. Okay. We're increasing the power
21 out of the fuel, increasing the core ΔT. You can see
22 the delta h term there from 74 BTUs per pound to 87.1
23 BTUs per pound; that's an increase of 17.5 percent.
24 Okay. That's actually greater than the total power
25 increase. And the reason for that is if you go down

1 another couple of lines you see the coolant mass flow
2 pounds per hour. That's actually decreasing slightly,
3 very slightly, minus 0.7 percent. That's a mass flow
4 rate. Volumetric flow rate is actually increasing
5 very slightly. But overall the flow is fairly
6 constant. We're increasing the core ΔT and that's how
7 we're getting the power out.
8 MEMBER WALLIS: I think what you said is
9 very clear. How does this relate to the table that's
10 in the SER where there are two different ways to get
11 the power uprate and they end up with a T_{Hot} of 615 in
12 one of those columns?
13 MR. FINLEY: Right.
14 MEMBER WALLIS: It doesn't seem to be the
15 same as your numbers here.
16 MR. FINLEY: Right. Right. And I'll
17 emphasize that these numbers are the nominal operating
18 parameters.
19 MEMBER WALLIS: They're nominal. But you
20 can operate with other kinds of numbers which might
21 lead to a higher T_{Hot}, for instance?
22 MR. FINLEY: That's correct. However, we
23 would fully analyze any change in these operating
24 parameters. We have control set points in the plant
25 that essentially control the plant to these

1 parameters. That's --

2 MEMBER WALLIS: But when you're doing the

3 safety submittal which numbers then do you use? Do

4 you use these ones or some of the numbers that are in

5 the SER, or something else?

6 MR. FINLEY: The safety submittal uses the

7 numbers in the SER. It uses the bounding safety

8 analysis --

9 MEMBER WALLIS: Okay. So it uses the

10 maximum T_{Hot}, the 615?

11 MR. FINLEY: That's correct. That's

12 correct.

13 MR. DUNNE: This is Jim Dunne from Ginna.

14 Basically what's in the safety submittal

15 is the range Tavg that the plant has been designed

16 for.

17 MEMBER WALLIS: Right.

18 MR. DUNNE: So now from an operation point

19 of view we have to stay within that band. So the Tavg

20 is chosen we look at the present condition of the

21 steam generators, the present fouling factor. We look

22 at basically the inlet pressure that we're designing

23 our new HP turbine to and we basically have to figure

24 out with the frictional loss in our system what

25 pressure we need back in the generator to get that

1 flow to the turbine to reach full power.

2 The secondary side pressure in the

3 generator then defines your T sat. And then we figure

4 out what Tavg we need based upon the present plant

5 conditions to basically get that power across the

6 generator tubes to --

7 MEMBER WALLIS: And during a fuel cycle

8 you might change these parameters?

9 MR. DUNNE: No.

10 MEMBER WALLIS: No?

11 MR. DUNNE: Typically when we replaced the

12 generators in 1996 we designed the RCS and the

13 replacement for a Tavg window from 561 to 573½. Our

14 original steam generator, our Tavg prior to

15 replacement have always been 573½ but our operating

16 experience had shown with plugging of the generators

17 due to defect mechanisms, steam generator pressure

18 fell off. And prior to replacement we were running

19 valves wide open on our turbine at reduced power level

20 because were volumetrically flow limited by the

21 turbine basically. So when we did the replacement, we

22 decided: (1) we'd put in steam generators to have

23 that greater surface area than the original

24 generators, and we decided we wanted to have a band --

25 we wanted to analyze the plant for a Tavg window so

1 that we could adjust Tavg as we needed to support any
2 degradation in steam generator performance, i.e.,
3 plugging as we went along.
4 We choose 561, which is at the bottom
5 range of the Tavg range, that we had analyzed for 1996
6 as our operating point at that point in time. And
7 that's the Tavg we have operated at from 1996 to the
8 present. We haven't seen any degradation in the steam
9 generator performance and basically we have had to
10 plug very few tubes. So there has been no need for us
11 to adjust Tavg from cycle-to-cycle. If we basically
12 saw we had to start plugging tubes and we were
13 basically going to valves wide open on the turbine and
14 we become power limit, then we would evaluate changing
15 the Tavg for a future cycle. But that Tavg that we
16 would change would have to fall within the 564 to 576
17 Tavg range that we've evaluated for the operate rate.
18 So for the present operating conditions we
19 are choosing a Tavg coming out of our refueling outage
20 of 574 to basically get us to the full power condition
21 with the new turbine.
22 MEMBER WALLIS: And when you're looking at
23 the conditions in the head if you're evaluating the
24 life of the head and the --
25 MR. DUNNE: We are addressing that.

1 MEMBER WALLIS: -- various things that
2 could happen --
3 MR. DUNNE: We use the upper band.
4 MEMBER WALLIS: -- you'd use the maximum--
5 MR. DUNNE: Yes.
6 MEMBER WALLIS: Do you use --
7 MR. DUNNE: All the analyses that were
8 done for the uprate project would either use the
9 minimum or the maximum Tavg, minimum or maximum T
10 cold--
11 MEMBER WALLIS: Whatever is --
12 MR. DUNNE: -- whichever was conservative
13 for the particular set of the analyses.
14 MEMBER WALLIS: Okay.
15 MR. DUNNE: Once we do that, now we need
16 to make sure we operate the plant within that band,
17 we're choosing a Tavg coming out of the uprate outage
18 of 574 to get to the power level, our license power
19 level. And based upon past experience, we've gone ten
20 years with 561 with no need to change it.
21 MEMBER WALLIS: So some of these things
22 are based on the conservative limit?
23 MR. DUNNE: Right. I think that's --
24 MEMBER WALLIS: But when you get to the
25 LOCA, it seems to me you're using a statistical

1 method.

2 MR. DUNNE: Right.

3 MEMBER WALLIS: You're using the best

4 estimate, which presumably are these values with some

5 variation around it?

6 MR. DUNNE: The best estimate LOCA would

7 use -- I think Westinghouse is in a better position

8 than I to answer that. But they would use a

9 conservative value with statistical uncertainty. I

10 don't think they used our nominal Tavg. They used a

11 normal design band for doing the best estimate.

12 MEMBER WALLIS: Because when you get near

13 some limit and the margin begins to disappear, it

14 makes a difference which one of these numbers you

15 choose to put in your analysis.

16 MR. DUNNE: Well, in theory since we've

17 done the analyses between the min and the max, we

18 should be able to operate the plant at any Tavg within

19 that window coming out of our uprate. And our

20 determination as to where we need to operate is the

21 574 number.

22 I think what happened with Waterford is

23 they were combining design numbers with operating

24 numbers, which is very confusing. What we're showing

25 here is a best estimate as to where the plant is

1 operating today for pressures and temperatures and
2 flow and where we expect the plant to operate coming
3 out of our refueling outage. And that should be within
4 the band of temperatures that were shown in the
5 licensing report.
6 MEMBER SIEBER: I have a couple of
7 questions just to clarify some things in my own mind.
8 Your original steam generators were model
9 44?
10 MR. DUNNE: That's correct.
11 MEMBER SIEBER: What's the square foot of
12 the replacement steam generators?
13 MR. DUNNE: The originals were model 44,
14 so they had 44,000 square feet. The replacements were
15 B&W Canada replacement we have 54,000 square feet. So
16 they're comparable to a Series 51 generator.
17 MEMBER SIEBER: Okay.
18 MR. DUNNE: Which is what basically
19 Kewaunee had.
20 MEMBER SIEBER: With the allowance for
21 690?
22 MR. DUNNE: Right. The other change we
23 made when we replaced the generators is we went from
24 Alloy 600 to Alloy 690. Alloy 690 has a slightly
25 lower thermal conductivity.

1 MEMBER SIEBER: Right.

2 MR. DUNNE: Which gives you little bit

3 more hydraulic consistency --

4 MEMBER SIEBER: Three percent.

5 MR. DUNNE: -- and to gooseup the surface

6 a little bit to compensate for the lower thermal

7 conductivity.

8 MEMBER SIEBER: Now the next question I

9 looked through the list of things that you changed in

10 the plant to accommodate the EPU. Could you describe

11 for me what steps, if any, that you took to evaluate

12 that the size of your pressurizer, which you aren't

13 replacement, is adequate for the uprate of power?

14 MR. FINLEY: Yes. I'll do that

15 specifically in the safety analysis area where we

16 discuss the results of the events that essentially

17 result in the sizing of the pressurizer.

18 MEMBER SIEBER: Okay. Well, one of the

19 key questions there is at a plant trip from full

20 power, where does the pressurizer level go? And if

21 the pressurizer is sized for a lower specific power

22 level, there is a chance that it would go below a good

23 operability limit and perhaps get a steam bubble in

24 the head if you emptied the pressurizer altogether.

25 And so I'm curious to hear more about that.

1 Now, I understand that you have selected
2 within a range of parameters. Your tech spec change
3 puts in the limits for all of these parameters, but
4 you expect to operate with some margins below those.
5 On the other hand there's nothing saying that you
6 couldn't operate at the limit, which in my view puts
7 T_{Hot} at 517, perhaps. And --
8 MR. DUNNE: 617.
9 MEMBER SIEBER: And the INCONEL 600
10 question then pops up that basically says there is
11 some kind of a transition point at 611. You would be
12 beyond that if you used all of your margin and
13 operated, for example if you had a lot of steam
14 generator tube plugging, you may be T_{Hot} but it is
15 beyond that. So the question becomes what remaining
16 uses in your reactor coolant system do you have for
17 alloy 600 or weld material 8182 which potentially
18 could be subject to cracking? And it may be buttered
19 joints, for example, and components are welded into
20 the reactor coolant systems. It may be in your
21 pressurizer surge line and so forth.
22 The next question is the pressurizer
23 operates at a higher temperature than any other place
24 in the plant, basically. And so what materials are
25 used in the pressurizer?

1 I note with your EPU you aren't changing
2 any of your pressurizer parameters. They will remain
3 the same. So you've become no more susceptible to this
4 today or in the future than you are today. But I'm
5 still curious as to what the materials are there and
6 what your operating and repair experience has been
7 with the pressurizer.
8 MR. FINLEY: Understand. And as Mark as
9 at the outset, we have replaced our head in 2003.
10 MEMBER SIEBER: Right.
11 MR. FINLEY: So that resolved the alloy
12 600 concerns on the head specifically.
13 MEMBER SIEBER: Right.
14 CHAIRMAN DENNING: And I'd like to defer
15 into the materials section where we discuss about
16 other materials.
17 MEMBER SIEBER: Okay. I've already
18 checked off my list of things; your head replacement
19 and steam generator replacement.
20 MR. FINLEY: Good. Good. And as you
21 mentioned with respect to the pressurizer, as you see
22 on this slide the nominal pressure in the pressurizer
23 is not changing.
24 MEMBER SIEBER: Right. So the temperature
25 is the same?

1 MR. FINLEY: The temperature in the
2 pressurizer is not changing. Right.
3 MEMBER SIEBER: On the other hand, the
4 volume becomes an issue for power uprate?
5 MR. FINLEY: Right. Right. And so we'll
6 touch on the volume and the sizing of the pressurizer
7 in the safety analysis section.
8 MEMBER SIEBER: Okay. Thank you.
9 MEMBER MAYNARD: Are you at T_{Hot} or T cold
10 head?
11 MR. DUNNE: This is Jim Dunne.
12 I believe we are basically considered to
13 be a T_{Hot} head. Typically I think we assume that the
14 head temperature is about ten degrees below our hot
15 leg temperature.
16 MEMBER MAYNARD: Okay.
17 MR. DUNNE: Or T_{Hot} temperature. Yes.
18 MEMBER MAYNARD: Okay. And that's what
19 I would have probable thought for your plant.
20 And also your steam generator 2 plugging
21 limit, what's your current analysis based on?
22 MR. FINLEY: This analysis is based on a
23 ten percent 2 plugging.
24 MEMBER MAYNARD: Ten percent?
25 MR. FINLEY: Yes.

1 Other questions? Good

2 I'd like to summarize the plant

3 modifications. Before I go down the list, I'd like to

4 say at the outset that the design objection for the

5 Ginna power uprate was to maintain the overall safety

6 and reliability of the plant at the uprated power

7 level. And several of these modifications did just

8 that, i.e., we didn't reduce margins with respect to

9 operation of pumps in the feed and condensate system

10 or cooling for the transfer or iso-phase. We

11 maintained the operating spare configuration, if you

12 will. And again, that maintains the overall

13 reliability of the plant operation.

14 MEMBER WALLIS: So your fuel is changing

15 with the upgrade? You have bigger rod diameter and so

16 on. So there's a while when you have a mix of fuels

17 in there?

18 MR. FINLEY: That's correct. That's

19 correct. There'll be two transition cores. And Gordon

20 Verdin will come up and talk in some detail on that.

21 MEMBER WALLIS: We'll get to that. We'll

22 get to that.

23 MR. FINLEY: With respect to the

24 modifications, the first three on this list are the

25 safety related modifications. As you can see, the bulk

1 of the modifications are to the balance of the plant,
2 and this is not a surprise. Mark had mentioned the
3 comparison to the Kewaunee plant, our sister plant,
4 who is operating to a very similar power level. We
5 have nearly identical NSSS systems. They've safely
6 operated at that power level now for more than a year.
7 So we expected with similar designs that we wouldn't
8 need significant modifications to the NSSS.
9 We are changing the fuel assembly. And,
10 again, Gordon Verdin will speak to that here shortly.
11 We are installing new actuators on main
12 feed isolation valves. They're manual valves now.
13 We're installing an air operator to automatically
14 close these values during a steam line break scenario.
15 We'll talk more about that with respect to the license
16 amendment associated with it.
17 MEMBER MAYNARD: Okay. So you're not
18 adding an valve into the system. You're actuator for
19 the existing valve?
20 MR. FINLEY: That's correct.
21 MEMBER MAYNARD: Okay.
22 MR. FINLEY: The air actuator on the
23 existing valve.
24 For the standby aux feedwater system, as
25 you probably know Ginna has a very robust aux

1 feedwater system overall. There's five aux feedwater
2 pumps, two are standby pumps. And for the standby
3 pumps the discharge valve internals will be replaced
4 to increase the flow slightly from that pump.
5 Probably the largest modification for the
6 uprate is replacing the high pressure turbine rotor.
7 Part of that modification is to also modify the
8 turbine control valves, essentially increasing the
9 throat area on those values to reduce the pressure
10 drop across the valves. Obviously what we want to do
11 is get more steam flow to the turbine and through the
12 turbine. We will be operating in the valves wide open
13 mode as opposed to the sequential valve opening.
14 MEMBER SIEBER: This isn't a safety
15 question, but I'm curious. In your modified turbine
16 how many stages will be impulse stages and, I presume,
17 everything in the high pressure turbine will be on the
18 impulse stage or stages that is reaction?
19 MR. FINLEY: Let me ask Jim Dunne to
20 answer that.
21 MR. DUNNE: Jim Dunne from Constellation.
22 Right now we have a partial arc of
23 Westinghouse turbines. We're going to a full arc
24 Siemens' turbine design.
25 MEMBER SIEBER: Okay.

1 MR. DUNNE: And they do not have an
2 impulse stage. They basically have all reaction.
3 MEMBER SIEBER: Everything is all
4 reaction?
5 MR. DUNNE: Everything is all reactionary.
6 MEMBER SIEBER: Okay. So you don't have
7 the nozzle blocks and --
8 MR. DUNNE: No. We do right now. And if we
9 did not replace the turbine, we would have had to have
10 gone in and rework the nozzle on our existing turbine
11 to get increase flow capability. Basically we went and
12 got bids for a new HP turbine because basically the
13 delta megawatt improvement with the new turbine design
14 for the new uprate verses modifying the old turbine
15 basically was favorable. And we looked at a number of
16 different of vendors with different designs. And we
17 choose Siemens, which is really the old Westinghouse
18 turbine owned by Siemens. And they basically what
19 they sell today is a full arc no impulse stage
20 turbine, and that's what we're installing. And as
21 part of that --
22 MEMBER SIEBER: But you would operate with
23 valves wide open regardless of what it is?
24 MR. DUNNE: Yes. You don't really want to
25 be fully wide open, but you basically you want to be

close to wide open on your full arc machine. You'd still have a little bit of bite, and basically running full open.

MEMBER SIEBER: Okay. And you're replacing not only the rotor but the casing?

MR. DUNNE: We're reusing the existing casing. We're just replacing the stationary blades and the rotating element. The outer casing cylinder and stuff is for the existing machine.

MEMBER SIEBER: Okay.

MR. DUNNE: We are replacing the turbine control valves because with the existing control valves with the increased flow we're getting a lot of pressure drop and we're basically going to a bigger control valve flow area point of view, we would minimize the pressure drop across the turbine control valve stage. The governor, the stop valves on the turbine will stay as the existing valves.

MEMBER SIEBER: And I presume that your new control system is digital as opposed to the old one which was hydraulic and mechanical, analog?

MR. DUNNE: At this point we're basically maintaining our existing control system.

MEMBER SIEBER: Which is an analog system.

MR. DUNNE: It'll be hydraulic, yes,

1 analog system.

2 MEMBER SIEBER: Yes.

3 MR. DUNNE: Independent of uprate, I think

4 there's an issue as to whether we should long term

5 replace the digital. But that's not being done as

6 part of our uprate. We are changing, you know, the

7 programming and some of the cards that go into that

8 system because of the new characteristics of the new

9 control valve and going from a partial arc emission to

10 a full arc emission, the philosophy.

11 MEMBER SIEBER: Okay. Thank you.

12 MEMBER WALLIS: So the low pressure

13 turbine is the same?

14 MR. DUNNE: Low pressure turbine is

15 exactly the same as we had.

16 MEMBER WALLIS: Do you have more

17 extraction or you have the extra ten percent flow goes

18 through the low pressure turbine.

19 MR. DUNNE: Basically the low pressure

20 turbine was not flow limited, so basically --

21 MEMBER WALLIS: So all the flow's going

22 through -- or there's a ten percent increase in flow

23 in the --

24 MR. DUNNE: The flow to the low pressure

25 turbine will increase, which is one reason why we have

1 to make modifications to our MSR relief system.

2 MEMBER WALLIS: And your condenser, too?

3 MR. DUNNE: Condenser --

4 MEMBER WALLIS: Safety. Probably not --

5 MR. DUNNE: Right. We'll have a higher

6 back pressure, obviously, at any given late

7 temperature for a condenser. But we're not making any

8 changes to our -- or system as part of our --

9 MEMBER SIEBER: But you have retube the

10 condenser?

11 MR. DUNNE: We did retube the condenser in

12 1995, went from an admirality tube to basically

13 stainless steel tube primarily to get cooper alloys

14 out of our feedwater system because of steam generator

15 corrosion issues.

16 MEMBER SIEBER: And these changes will

17 increase the extraction pressure side of your feed

18 heaters?

19 MR. DUNNE: Yes, that's correct. All the

20 extraction pressures will increase. The one that we do

21 have some control over with the HP turbine

22 modification, our final feedwater heat, our high

23 pressure heater because that comes off of the HP

24 turbine point. And so we defined a final feedwater

25 temperature for the uprate that Siemens is designing

1 too with their HP turbine.

2 MEMBER SIEBER: Okay. So that means you

3 have more stored energy. You may have to change relief

4 valve settings on the feed heaters. And the other

5 thing is that if you trip, there is more stored energy

6 and therefore more of a propensity to go to overspeed

7 faster?

8 MR. DUNNE: We --

9 MR. FINLEY: Right. Right. For both of

10 those comments, the relief valves on the feedwater

11 heaters and the stored energy for overspeed trip

12 setting on the turbine, we've incorporated the new

13 conditions in our analyses.

14 MEMBER SIEBER: And it's satisfactory.

15 MR. DUNNE: Yes.

16 MR. FINLEY: Yes. No modifications to the

17 relief valve. We are changing the over speed trip

18 settings slightly.

19 MEMBER SIEBER: Thank you.

20 MR. FINLEY: To continue down the list of

21 modifications. For the main feed and condensate

22 train, we are replacing the impellers on the main feed

23 pumps and the motors on the main feed pumps and also

24 the impellers and motors on the booster pumps,

25 obviously to get the additional flow through

1 condensate feed.

2 The feed regulating valve is being changed
3 to a valve with a passing greater flow. And also the
4 bypass valve on the feed regulating valve; the
5 internals there are being replaced.

6 Cooling for some of the electrical systems
7 is being upgraded. For example, for the main generator
8 we're replacing the condensate cooler which cools the
9 water into the hydrogen coolers on top of the main
10 generator, you know for the greater I squared R losses
11 in the main generator.

12 The step up transfer is getting an
13 additional cooler bank. This is one of the
14 modifications I mentioned to you. We have an
15 installed spare now. It was necessary that we modified
16 the cooling system for uprate, but we would have had
17 to use the installed spare. We put a new cooler bank
18 in, so we still have an installed spare.

19 Similar with the iso-phase bus ducts.
20 We're adding a third fan. We have two fans now.
21 Typically those two fans run all the time and that
22 flow would have been adequate for the cooling. We're
23 installing a third fan, again to provide an operating
24 spare. For upright, we'll need to have those two fans
25 operating whereas currently technically we would only

1 need one fan operating.

2 And finally, the underground oil cables,

3 and Joe Pacher will talk more about this this

4 afternoon, but we have oil filled eight inch cables

5 that run from the site transformer across the street

6 to the switch yard. And we're instituting a forced

7 flow of that oil system. All that pumping and piping

8 is available now, and it's been available since the

9 site was originally constructed. We're putting those

10 pumps in operation at this point to circulate the oil.

11 And that will only be required for the warm months of

12 the year.

13 Moisture separator reheater relief system.

14 As we talked about, the pressures will increase here

15 and the flow requirements will increase. And we're

16 making modifications to that.

17 There will be various heater drain minor

18 modifications to piping, vent systems and so forth to

19 handle the increased flow rates.

20 Minor support changes all in the balance

21 of plant, and this is in response to the higher

22 transient loads. When you shut turbines and stop

23 valves and/or feed reg valve, those transient loads

24 are higher and there are some beefing up of supports

25 that will be needed.

1 And the finally, this will be talked about
2 more in Rob's risk presentation, three modifications
3 that specifically relate to risk benefits. We're
4 adding a backup air system for the charging pumps and
5 we're adding some controls for both the charging pumps
6 and the turbine driven aux feed pump to help the
7 operator response, particularly in fire scenarios.
8 MEMBER MAYNARD: You're talking about
9 local controls or operating outside the control room?
10 MR. FINLEY: That's correct. That's
11 correct. For scenarios where the operators need to
12 evacuate the control room and operate these components
13 locally.
14 With respect to license amendment, Pat
15 Milano touched on these briefly, but I'd like to
16 summarize. Obviously the important amendment relates
17 to changing the power level, allow the core thermal
18 power increase to 1775 megawatt thermal.
19 LOCA methods we are updating to the newest
20 approved Westinghouse BE LOCA method. ASTRUM versus
21 an older BE LOCA, SECY-83-472 method.
22 Axial offset control we're changing from
23 the constant methodology to a relaxed methodology
24 which changes the limits on axial flux distribution.
25 MEMBER SIEBER: Could you explain that in

1 more detail, please?

2 MR. FINLEY: I'll defer to Gord Verdin if

3 you can wait when he comes up with the fuel

4 discussion.

5 MEMBER SIEBER: Okay.

6 MR. FINLEY: We are increasing the maximum

7 allowed boron concentration for the accumulators and

8 the refueling water storage tank. And that's to allow

9 for a higher boron for the hold down reactivity at

10 beginning of life in the core.

11 Minimum value in the actuator is actually

12 reduced slightly. This is really not due to the

13 uprate, per se, but because we were doing the analyses

14 we got a little bit more margin for our uncertainty

15 calculations for the level setpoints on the

16 accumulators here. So we reduced that slightly.

17 MEMBER SIEBER: But you aren't going to

18 change any setpoints? You're not going to change any

19 setpoints?

20 MR. FINLEY: That's correct. We're

21 actually not changing the level --

22 MEMBER SIEBER: So the levels will be the

23 same, just more margin?

24 MR. DUNNE: The control that I used at ops

25 controls the accumulator level, too, it would be the

1 same. We're just giving them more margin with tech
2 specs, like Mark said, primarily to accommodate to
3 give us more instrument uncertainty margin going
4 forward.
5 MEMBER SIEBER: Thank you.
6 MR. FINLEY: The condensate storage tank
7 minimum volume in the technical specifications will be
8 increased. And this is due to the basis for that tank
9 to provide two hours of decade heat removal
10 capability. Obviously, our decay heat will be
11 increasing.
12 The feed isolation valve that we talked
13 about modifying is actually a back-up valve to the
14 feed regulating valve. The feed regulating valve is
15 the primary closure that we rely on in a main steam
16 line break. It actually closes in ten seconds. This
17 new valve will be closing in 30 seconds. However,
18 that's faster. You can see here twice as fast as the
19 current valve that we have in the tech specs, which is
20 the feed pump discharge valve.
21 So not only will be the valve be closing
22 faster, the new valve, it's also closer to the steam
23 generator down the pipe further. So that's better from
24 the standpoint of shutting off the hot water in that
25 pipe closer to the steam generator.

1 And then finally there are changes to the
2 safety setpoints, and I'll defer to the safety
3 analysis section and talk about each of those
4 specifically.
5 And the last thing I'd like to speak to at
6 this time is the importance of industry operating
7 experience. This has been factored into every aspect
8 of the project for the Ginna power uprate. I'm going
9 to touch briefly here on a few of the topics to give
10 you a sense of what we learned, but by no means is
11 this a complete list.
12 Vibration induced failures, obviously
13 we've understood the history of vibration induced
14 failures throughout the industry, specifically on
15 small bore piping. One of the things we're doing here
16 is incorporating all of the failure points that we've
17 seen in industry, and in fact all of the small bore
18 piping that's tied to the large piping that will see
19 flow increases, and made that a part of our vibration
20 monitoring plan as we escalate the plant.
21 MEMBER SIEBER: The architect engineer for
22 your plant was Stone & Webster?
23 MR. DUNNE: No. The original architect
24 engineer was Gilberts. Ginna was a turnkey plant and
25 Westinghouse was basically responsible for picking the

1 AE and the constructor. And for the Ginna of Ginna,
2 they chose Gilberts.
3 MEMBER SIEBER: Back in the days when your
4 plant was built the piping engineers typically did not
5 do a rigorous analysis on supports for small bore
6 piping, particularly a seismic analysis. They used
7 templates and said at, you know, every 20 feet I'm
8 going to put a hanger and it'll look like this out of
9 their cookbook.
10 Have you ever gone back and reanalyzed
11 with modern analytical tools the response and support
12 system for your small bore piping or are you still
13 relying on the template type of hanger design?
14 MR. DUNNE: For our safety related systems
15 in the late '70s early '80s, we went back and did a
16 seismic upgrade program, but that was I think for
17 piping two inches and larger in general. The small
18 bore piping we're just basically using engineering
19 judgment for adequate supports.
20 Balance of plant there was no attempt to
21 go back and redo that. It's primarily based upon
22 operating experience where if we see support damage or
23 something, we'll go in and analyze it to see what
24 could have caused it and whether it's something
25 related to design that needs to be changed.

1 MEMBER SIEBER: Okay. That's typically
2 what licensees did in that period. And that leaves out
3 things like vents and drains and instrument impulse
4 lines. In the history of your plant have you had
5 cracks or other failures of those types of lines;
6 vents and drains and --
7 MR. DUNNE: We've had some socket weld
8 failures. I don't think we've had a lot of them, but
9 we've had some of them. Usually they attribute it to
10 a construction defect that basically propagates over
11 the operating life of the plant.
12 MEMBER SIEBER: Okay. But you've never
13 had one break off? You just have cracks that caused
14 leaks, right?
15 MR. DUNNE: I'm not aware in the time I've
16 been there of any that have broken off. The one event
17 that I am aware of is that we had a pre-separator tank
18 fail on us in the early '90s, which was an erosion
19 issue due to an inadequate material. And we --
20 MEMBER SIEBER: What was the tank again?
21 MR. DUNNE: It's a pre-separator. Ginna
22 on the HP turbine outlet to the MSR inlet installed
23 pre-separators to a decreased moisture loading --
24 MEMBER SIEBER: Okay.
25 MR. DUNNE: -- on the MSR separator, if

1 you will, in the mid '80s. It's a skimmer basically
2 in the piping going towards the MSR to try and do some
3 preferential moisture removal. The moisture that
4 removed is routed to a tank and then gets trained to
5 a feedwater heater through a control valve. In the
6 early '90s we had one of those tanks fail on us due to
7 erosion --
8 MEMBER SIEBER: Yes.
9 MR. DUNNE: -- within the tank due to an
10 inadequate material. That's the biggest thing that I
11 remember. We basically went in and modified all our
12 tanks.
13 One of them failed, I believe we have two.
14 Yes. And so we modified the one and then the next
15 refueling outage we replaced both tanks with new tanks
16 with basically upgraded materials for erosion issues.
17 MEMBER SIEBER: Okay. Thank you.
18 MR. FINLEY: And let me ask Roy Gillow
19 audience. He's operated the plant for many years. He
20 can speak to experience here.
21 MR. GILLOW: Yes. I'm a senior reactor
22 operator. I've worked 23 years at operations. And I
23 recall any kind of failure like you're talking to.
24 The things we've had is impingement issues in some
25 extraction steam lines like Jim mentioned. But never

1 any failure of vibration induced failure of a line
2 that I'm aware of.
3 MEMBER SIEBER: Okay. Thank you very
4 much.
5 MR. FINLEY: With respect to the turbine,
6 one of the lessons learned in the industry is when you
7 go to these more efficient low clearance machines that
8 the likelihood of rubs especially during power
9 increase or coming up to speed and low powers
10 increases, and one of the things we learned here was
11 that you can't have an asymmetric lineup of your
12 feedwater heaters on the turbine. It sets up a
13 gradient across the turbine which can cause these
14 rubs. So we're going to factor that into our
15 operating process.
16 Turbine control valves. Again, we're
17 going to the valves wide open mode. One lesson we
18 learned here is that instead of having all four valves
19 come off their shut seat when you initially come up in
20 power and starting the plant up, is to stagger two of
21 the valves slightly. And so we have more bite on two
22 of the values, and the other two will lag for some
23 period of time before they all come up together. So
24 this will help the control issues.
25 Iso-phase. You're probably aware of

1 failures due to flow induced vibration in iso-phase
2 bus ducts. These happened at plants that significantly
3 increased their air flow in the bus ducts. We have a
4 small increase in air flow, but well within what our
5 analyzed limit is for increasing vibration in the bus
6 ducts.
7 We've also carefully looked at the heat
8 loads on the system to make sure that that flow is
9 adequate to handle the heat removal.
10 Step-up transfer cooling. There have been
11 issues for plants that didn't really understand the
12 heat loads on their cooling system. And in particular
13 they didn't understand what the ambient loading, the
14 ambient air temperature was surrounding their
15 transformers. We did a study during the hottest time
16 of the year to verify what the ambient conditions
17 before we analyzed the heat loads.
18 Power measurement. There's been issues
19 with respect to secondary calimetric calculations in
20 particular. And Ginna's looked at all of the inputs
21 to the secondary calimetric calculation and verified
22 that we have the right scaling, that we have the right
23 ranges on all those inputs and that the accuracy won't
24 be compromised.
25 And then finally with respect to operating

1 setpoints: Steam pressure, T_{Hot}, ΔT all those have
2 been issues. We've looked carefully at the margins
3 there. We've used Westinghouse to optimize the
4 margins. And we feel we have plenty of operating
5 margin to be.
6 And with that, I'll conclude my first
7 presentation.
8 I'd like to introduce Dave Wilson who is
9 the licensing lead for the project to discuss the
10 process.
11 MR. WILSON: Good morning. I'm David
12 Wilson. I'm a principle engineer at Ginna Station.
13 I've been there about 20 years.
14 Most notable last accomplishment was I
15 worked on a license renewal project. I'm contributing
16 to power uprate here.
17 What I'd like to talk about is RS-001
18 submittal, the fact that we added some additional
19 sections, the level of staff interaction we had and
20 the level of review effort we made. I'll be brief.
21 What we wanted to do was give them
22 everything that they asked in RS-001 plus everything
23 we think they needed based on operating experience
24 from other utilities. And we got a lot of coaching
25 and a lot of good interactions with the staff, so we

1 were very pleased with that.

2 In order to pull the job off successfully

3 we added some unique sections that aren't in the RS-

4 001 document. We talked about our renewed operating

5 plant license in every section that had an impact. We

6 talked about the system evaluation program we

7 underwent in 1970s and '80s and how that relates to

8 our CLB, our current licensing program. And we gave

9 them a section 1 to RS-001 which we considered to be

10 a roadmap of lessons learned that allowed the staff

11 and the station to enter the dialogue on how to relate

12 the facts that were not designed for the standard

13 review plan, and have opened an honest dialogue and

14 discussions.

15 We met frequently with the staff. We had

16 very timely meaningful interactions. That is, as you

17 heard, before we had presubmittals and that allowed us

18 to keep working on the major submittal while giving

19 the government an opportunity to work on the long lead

20 time evaluations.

21 Everywhere we had the opportunity we

22 incorporated lessons learned.

23 We had no surprises in our review effort.

24 Communications were prompt and they were very clear.

25 And we worked through the issues.

1 We had a very rigorous owner acceptance
2 review of our vendor inputs. Our acceptance reviews
3 were proceduralized and we did get quality assurance
4 reviews of those to make sure that we were following
5 our procedures. And, by in large, the NRC reviews went
6 very well. The questions that were asked were
7 meaningful and relevant. And it was pleasurable to
8 have a line of reasoning with RAI that came in. That
9 really kept us from having miscommunications and delay
10 sin the process.
11 MEMBER WALLIS: You had all these
12 interactions with the NRC. Did you have some reviews
13 from sister plant people or some sort of internal --
14 MR. WILSON: Yes, we did. We had --
15 MEMBER WALLIS: Did you find that useful?
16 Did you get information which you wouldn't otherwise
17 have got that way?
18 MR. WILSON: Oh, absolutely.
19 MEMBER WALLIS: All right.
20 MR. WILSON: And we also fostered that in
21 the industry. We're now providing our expertise, if
22 you will, to other utilities. You know we're trying
23 to push the lessons learned throughout the industry.
24 So we had principally Kewaunee was a very big help to
25 us. And we had them up several times.

1 We had a sequester week where we took
2 industry experts and our staff and our vendor experts
3 and we locked ourselves away for a full week going
4 over the hard issues and reviewing the operating
5 experience and trying to make sure that we actually
6 understood the implications of some of the operating
7 experience that we saw in the industry, and that we
8 correctly dealt with it.
9 It was a pretty rewarding project to work
10 on. We were pleased with the interactions of the
11 staff.
12 If there are no questions for me, I'd like
13 to introduce Gord Verdin. He's our fuel lead.
14 MR. MILANO: We had originally planned for
15 a break now. But we can go on.
16 MR. FLAHERTY: Yes. We'll go on.
17 MR. MILANO: I'd like to take a break
18 after his?
19 MR. FLAHERTY: After that?
20 MR. MILANO: Thank you.
21 MR. FLAHERTY: That would be fine.
22 MR. VERDIN: Good morning. My name is
23 Gord Verdin, I'm a principal engineer at Ginna
24 Station. I'm the principal engineer for the primary
25 systems and reactor engineering group. I've been at

1 Ginna for 9 years. In those 9 years I've served
2 primarily in the areas of reactor engineering, steam
3 generator engineering and also in engineering
4 analysis.
5 I do have an SRO certification and I was
6 an STA for a year and a half.
7 Prior to that I worked for 4½ years at
8 Babock & Wilcox Canada as a steam generator thermal
9 hydraulic designer and as a steam generator service
10 engineer.
11 Today I'm going to talk about fuel and the
12 core, in particular the fuel assembly design that
13 we're going to be implementing with the EPU. The goal
14 of this fuel assembly design was to recover and
15 improve margins for the EPU compared to the current
16 fuel. And also we will be adding some additional
17 robust features that Westinghouse has implemented over
18 the last several generations of fuel that they've
19 made.
20 MEMBER WALLIS: In getting the power
21 uprate, this means you have more fission material in
22 the core?
23 MR. VERDIN: That is correct.
24 MEMBER WALLIS: Is it roughly
25 proportional? Do get the same sort of burnups the new

1 fuel?

2 MR. VERDIN: The burnups will be similar.
3 We're currently we're as far as average fuel assembly,
4 discharge burnups are approximately 50,000 megawatts
5 days per MTU. That should be similar. The actual per
6 fuel assembly uranium loading is going up from about
7 346 kilograms uranium to about 396 kilograms of
8 uranium.

9 I'm going to talk about core design
10 briefly. Some of the strategies and the number of
11 feeds that we'll be doing. Obviously as part of this
12 uprate, it's a fairly large uprate, we will be putting
13 in additional feed assemblies over what we normally
14 would for the first two cycles. Then we'll get back to
15 a number of assemblies that's similar to what we're
16 using currently.

17 And then lastly I'm going to talk about
18 core operating limits. This is where I'll address the
19 CAOC versus RAOC question that was asked previously.

20 In front of you can see the diagram
21 showing both the current Ginna 14 by 14 optimized fuel
22 assembly, that's the OFA. I'll refer to it as OFA from
23 now on. And on the right side you'll see the new 422
24 Vantage Plus 9 grid Ginna assembly.

25 The significant changes that we've

1 implemented here are the rod outside diameter is going
2 to be changing from .4 inches to .422 inches. That
3 obviously gives you a larger surface area and helps to
4 recover DNBR margin that you -- as a result of the
5 uprate, obviously, we do need to cover margins and
6 that's one of the way that we do that. That also,
7 obviously supports the increase in uranium inventory
8 that I had previously discussed.
9 MEMBER WALLIS: This gives a higher fluid
10 velocity?
11 MR. VERDIN: Yes. The fluid velocities
12 are higher. And what I will address is the thermal
13 hydraulics. It seems a little counter-intuitive. When
14 you first see it, you think that you're going to see
15 a reduction in volumetric flow. I will address that.
16 The fuel rod lengths themselves will be
17 increasing 3.6 inches and the fuel stack will be
18 increasing 1.85 inches.
19 MEMBER WALLIS: And all this increase
20 seems to be in the last little piece between grids 8
21 and 9, is it?
22 MR. VERDIN: Correct. I will address
23 degree issue --
24 MEMBER WALLIS: You will address that,
25 too. in

1 MR. VERDIN: -- as well momentarily.

2 But this rod length and fuel stack you'll
3 see that we're actually building in additional plenum
4 length inside each fuel rod. That plenum length helps
5 to accommodate the additional fission gases and also
6 the gases from burnable absorbers, the Zirc diboride
7 obviously generates helium gas it burns up. So that's
8 a margin enhancement to increase the plenum length.

9 The other thing is the increased fuel
10 stack. By increasing 1.85 inches you obviously also
11 reduce your linear heat generation rate for a given
12 power level. So it does give you some margin in terms
13 of central line temperatures and that sort of thing.

14 One of the things you can see as a result
15 is the top nozzle for our fuel will be changing. The
16 current 059 grid assembly has a unique -- I believe it
17 is now unique, there was nobody else that was using
18 that anymore. We will be going to the standard
19 Westinghouse top nozzle, which is the shorter top
20 nozzle that's pictured.

21 MEMBER SIEBER: During a couple of cycles
22 you'll be operating with both types of fuel?

23 MR. VERDIN: That's correct. For two
24 cycles.

25 MEMBER SIEBER: When I look at those from

1 a seismic standpoint, the grid straps are supposed to
2 align to give you lateral support. On the other hand
3 in your operated fuel assembly the top strap does not
4 have a counterpart for support?
5 MR. VERDIN: That's correct.
6 MEMBER SIEBER: Has that been analyzed and
7 is that satisfactory from the seismic standpoint?
8 MR. VERDIN: Yes. Originally we are a nine
9 grid assembly, which is unique as well. Most
10 Westinghouse assemblies including the other 422V+
11 products that are out there are seven grid assemblies.
12 Originally we even looked at potentially
13 going to a seven grid assembly. But overall, you could
14 not make this work with the grid assembly -- or the
15 grid height mismatches that you would.
16 Early on in the project during the
17 implementation of this or the design and
18 conceptualization phase, there was a lot of discussion
19 as to whether we put those two grids such that there
20 is some overlap, that's the top grid I'm referring to,
21 or whether we go this way.
22 MEMBER SIEBER: Yes.
23 MR. VERDIN: There's really benefits and
24 detractor from either approach. If you put them,
25 obviously, in a line that you get better, there's less

1 cross flow at that grid because obviously grid height
2 mismatch is also a source of crossflow. If you
3 actually look at it, it can exacerbate crossflow.
4 The disadvantage is that you would have to
5 put that rod or that grid so far below the top of the
6 rod that you have a long length, and that turns out to
7 be a sensitivity in terms of vibration.
8 In the end what was determined was they
9 did extensive analytical analysis. We've also tested
10 these two assemblies next to each other at
11 substantially higher flows. And the results of the
12 testing and the results of the analysis really
13 indicated that either approach would have worked.
14 However, this approach for the long term once we get
15 to cores that are all 422V+ is superior.
16 MEMBER SIEBER: Now the purpose of the
17 testing that you did, was that to evaluate and learn
18 about the degree of mixing or to look at the strength
19 of the assembly and the seismic characteristics, or
20 both?
21 MR. VERDIN: There were multiple types of
22 tests.
23 MEMBER SIEBER: Okay.
24 MR. VERDIN: There was testing, the
25 original testing is what's called the FACTS loop,

1 which is basically you put the fuel assembly by itself
2 in the loop and you pass flow through it. It's used
3 to validate hydraulic design aspects, pressure drops,
4 that sort of thing.
5 There's also what's called the VIPRE test.
6 And the VIPRE test is where you actually put an OFA
7 fuel assembly next to one of the new fuel assemblies.
8 And they run it for an extended period of time,
9 several months, at higher than design flows. They
10 have a whole bunch of various things to look at
11 individual rod vibration, fretting; that sort of
12 thing. Looking at compatibility.
13 MEMBER SIEBER: Yes.
14 MR. VERDIN: And then there's other
15 testing specifically what you're referring to,which is
16 the seismic. There's grid crush testing --
17 MEMBER SIEBER: Right.
18 MR. VERDIN: -- on individual grids where
19 they heat the grids up to operating temperature and
20 then they basically put enough energy into them to
21 verify that they're adequate.
22 As far as seismic design, the fuel
23 assembly was designed for LOCA plus SSE. One of the
24 licensing basis, things that will be discussed later,
25 is the changing to the leak before break to limit the

1 size of different breaks that can occur. And under
2 those conditions, under the licensing basis LOCA SSE
3 there's at least a 50 percent margin. Approximately
4 half of the allowable loading was what was calculated
5 in a mix core, in a transition core.
6 MEMBER SIEBER: A couple of other
7 questions.
8 MR. VERDIN: Yes.
9 MEMBER SIEBER: The grids themselves, the
10 support for the rod is brought about by having to
11 dimples that are at adjacent corners, two springs.
12 MR. VERDIN: That's correct.
13 MEMBER SIEBER: With a larger rod that
14 means you have to reduce the size and defection of the
15 spring. Does that change the stability at all?
16 MR. VERDIN: Like I said, there was
17 testing done where they put the 422V+ and OFA
18 together. They run them at substantially higher flows
19 than they will see in the reactor to determine the
20 stability, to look at threading. And the 422V+ design
21 with the larger dimples that we have, that we're going
22 to be having with this new fuel, showed excellent
23 fretting capability, which would obviously indicate
24 that you have adequate holding force.
25 MEMBER SIEBER: Okay. Now the grid straps

1 have little tabs and vanes and wings in order to
2 promote mixing?
3 MR. VERDIN: That's correct.
4 MEMBER SIEBER: And it seems to me that
5 you have a smaller overall cross section, smaller
6 footprint here. So I would expect the flow to be less,
7 but I think you said the flow is greater. Does that
8 mean you sacrificed in the tabs and vanes and wings in
9 the mixing area?
10 MR. VERDIN: What we have done is we have
11 gone to a new grid design that has thinner straps. The
12 thinner strap design, basically the reduction in
13 pressure drop at the grids, offsets the increase in
14 pressure drop due to friction along the fuel rods.
15 So, yes, the straps are thinner. The straps themselves
16 went through what's called a VISTA high-frequency test
17 where they basically looked at fatigue of the straps
18 and that sort of thing and determined that the straps
19 were adequate for the design.
20 Also, this is obviously similar to designs
21 that are in service. The 422V+ has seen three cycle
22 service at Point Beach. I believe it was put in at
23 Point Breach in 1997. And it has been discharged and
24 it has had satisfactory experience.
25 One of the changes we did make to the

1 grids I should mention is we have gone to a balance
2 vane design.
3 MEMBER SIEBER: Okay.
4 MR. VERDIN: The 422V+ product that's in
5 service right now, it does not have a balanced vane
6 design. And as a result, that potentially can be
7 resonately self excited because it has a net force.
8 The balanced vane design actually rotates the vanes in
9 the four quadrants of the grid to reduce the net
10 force. And we have implemented that. That's a robust
11 features that's implemented from previous Westinghouse
12 designs.
13 MEMBER SIEBER: Okay. Now the grid straps
14 made out of Zircaloy?
15 MR. VERDIN: No. The replacement grid
16 straps will be made out of ZIRLO.
17 MEMBER SIEBER: ZIRLO.
18 MR. VERDIN: It's a --
19 MEMBER SIEBER: All except for the
20 springs?
21 MR. VERDIN: No. The springs are part of
22 the grid. They're stamped in it.
23 MEMBER SIEBER: Oh.
24 MR. VERDIN: The only grids that are not,
25 there's alloys --

1 MEMBER SIEBER: You're not worried about
2 the spring relaxing due to irradiation?
3 MR. VERDIN: There is spring relaxation as
4 a result of irradiation, but that's evaluated as part
5 of the test. And on the test --
6 MEMBER SIEBER: So it still work at the
7 end of life?
8 MR. VERDIN: -- because we don't irradiate
9 it.
10 Pardon?
11 MEMBER SIEBER: It will still work at the
12 end of life? It maintains contact all the way to the
13 end of life?
14 MR. VERDIN: That's correct. I don't
15 remember the criteria. I think it might be one pound
16 that it's supposed to be maintained.
17 MEMBER SIEBER: Well, if you don't do
18 that, it'll fret and then you got a damaged fuel
19 assembly.
20 MR. VERDIN: Right. Right. And like I
21 said, there is 422V+ product has been irradiated for
22 three cycles and discharged with adequate service
23 history. No known failures.
24 MEMBER SIEBER: Do you have any idea as to
25 how big a particle, an impurity particle would be that

1 would still make it through the fuel assembly without
2 getting snagged on a grid strap or caught in between
3 two rods, or captured someplace in order to block the
4 flow?
5 MR. VERDIN: The Ginna --
6 MEMBER SIEBER: For example when you're in
7 recirculation.
8 MR. VERDIN: Right.
9 MEMBER SIEBER: And you're pumping gravel
10 through your system.
11 MR. VERDIN: Right. As far as the Ginna
12 fuel design, we do have a debris filtering bottom
13 nozzle. We've had that for some time. I believe the
14 holes in the debris filter bottom nozzle are .23
15 inches. I remember looking at it a few weeks ago,
16 that's the number that sticks in my head.
17 But if you look, the actual bottom nozzle
18 will filter.
19 MEMBER SIEBER: Okay. So the debris --
20 well, that prevents you from getting debris up in the
21 fuel and vibrating and making a hole. On the other
22 hand, all the debris could go to that bottom nozzle
23 and block it.
24 MR. VERDIN: Correct.
25 MEMBER SIEBER: Has that been evaluated?

1 MR. VERDIN: That is currently -- Ginna is
2 implementing an active strainer design --
3 MEMBER SIEBER: Yes.
4 MR. VERDIN: -- that's going to be
5 installed during our 2006 outage.
6 MEMBER SIEBER: An active strainer?
7 MR. VERDIN: That's correct. I think we'll
8 be the first plant to implement an active strainer.
9 MEMBER SIEBER: You'll be one of four,
10 yes.
11 MR. VERDIN: Yes. That's being evaluated
12 as part of the downstream effects analysis. I haven't
13 been really involved in that, so I'll have to defer
14 to--
15 MEMBER SIEBER: What part of your strainer
16 is active? What does it do? Scrap or --
17 MR. VERDIN: What it's got is it's too
18 large boxes. I believe they're about three feet
19 square. And on top of them they have a comb and
20 sweeper design with a motor that obviously sits up
21 high enough as to not be potentially impacted by the
22 water level in the containment at that point. And they
23 basically have from those large boxes that are
24 perforated and have the perforated top, there's
25 perforated pipes that go over to the sump. The sump

1 itself will be sealed. The current sump such that all
2 water has to go through this strainer mechanism.
3 MEMBER SIEBER: And that will receive
4 emergency power?
5 MR. VERDIN: Yes, that's correct.
6 MEMBER SIEBER: Safety grade power.
7 MR. VERDIN: Correct.
8 MEMBER SIEBER: Okay. Thank you.
9 MEMBER MAYNARD: A quick question on the
10 PLV. There's been a number of fuel failures in the
11 industry associated with new fuel designs supposed to
12 improve overall fuel design. Is this a new design or
13 do you have unique aspects for your new fuel or is
14 this a proven --
15 MR. VERDIN: This is based upon a proven
16 design, which is the 422V+ that's currently in
17 service. I believe the lead plant was Point Beach. I
18 think it was 1997. So it has seem full -- a full
19 irradiation for three cycles and it has been
20 discharged. It's also now in use at Kewaunee.
21 The changes that we have versus those
22 plants, obviously we have the nine grid design versus
23 the seven grid design. We talked about swapping over
24 to a seven grid, couldn't make it work.
25 The other features that we've got that

1 they don't have, I actually will get to them a little
2 bit, but basically they're things like the balance
3 vane design. That's a robust feature. That's
4 something that we added to improve our fuel assembly
5 over their fuel assembly based upon other robust fuel
6 designs that are in service.
7 We've also done a couple of other things
8 to our fuel. We increased the rod length .2 inches;
9 that's to provide additional plenum volume, more
10 margin for rod internal pressure issues.
11 We also when we first went down the path
12 of this fuel transition, we were going to use an
13 identical fuel rod design to those plants. However,
14 because of rod internal pressure it was decided that
15 we would remove pellet from our fuel stack to get this
16 143.25 inch fuel stack.
17 So there are slight differences, but in
18 general it's very similar to that project.
19 MEMBER MAYNARD: I would caution because
20 sometimes some very minor changes that were supposed
21 to improve turns out to create an unexpected problem,
22 too.
23 MR. VERDIN: Right. Okay. Thank you.
24 MEMBER WALLIS: Is this a fairly simple
25 fuel design or is it one of these custom tailored

1 things that has varying enrichments at different
2 places and all that?
3 MR. VERDIN: No. This fuel assembly design
4 has within the fuel assembly itself other than the
5 axial blankets at the top and the bottom, it has a
6 common enrichment, okay?
7 MEMBER WALLIS: It's uniform? Okay.
8 MR. VERDIN: That's correct. It has 2.6
9 percent min. enriched annul or axial blankets. We have
10 annul or axial blankets to provide additional gas
11 plenum volume. Again, a lot of this comes down to
12 these rod internal issues.
13 The assemblies have multiple burnable
14 absorber patterns. They can go anywhere from 16 to 64
15 to 100 rod burnable absorber patterns per assembly.
16 That's core design specific. But other than that, no,
17 it's not a particularly -- it's actually quite similar
18 to what we have right now with the features that I've
19 said. Okay?
20 One of the things I just wanted to mention
21 briefly is the top nozzle on the 422V+ design you can
22 see that it sits higher. That does have some impacts
23 on our rod position indicating system and on our
24 control rods. Currently our control rods will go out
25 to 230 steps. The new control rod maximum will be 325

1 steps.

2 The other thing is the microprocessor rod
3 position indicating system that Ginna has is a unique
4 system. Because of the way it's a unique system that
5 every 12 steps reads the end of the drive rod, we have
6 to do some firmware changes to our microprocessor rod
7 position indicating system. And those are in progress.

8 MEMBER MAYNARD: I don't know if you're
9 going to cover this later or not, but it looked like
10 during these transition cycles you're going to have
11 potentially some differences in rod height
12 indications?

13 MR. VERDIN: Correct.

14 MEMBER MAYNARD: Is that going to be
15 handled -- I don't know how confusing that's going to
16 be in the control room or on your system or for the
17 operators there?

18 MR. VERDIN: For the first cycle, and for
19 the first cycle only we will have either one or two
20 banks of control rods that will be over OFA fuel.
21 Okay? The remainders will be over the new 422V+ fuel.

22 What we plan to do is once we close the
23 trip breakers, is we plan to go into bank mode,
24 withdraw those banks, five steps, and then basically
25 reset the rod control system such that it thinks that

1 everything is at zero steps. That way there should
2 really be no impact on the operator at all.
3 MEMBER MAYNARD: Okay.
4 MR. VERDIN: Other than, obviously the
5 process of the original extraction by five steps.
6 Okay?
7 MEMBER SIEBER: Have you done the core
8 design yet?
9 MR. VERDIN: The core design?
10 MEMBER SIEBER: So you know what fuel will
11 go where?
12 MR. VERDIN: We have a candidate, a likely
13 candidate loading pattern that's in the process. one
14 of the issues that we've had with this transition is
15 the OFA fuel does have a small plenum length so it is
16 more limiting from a rod internal pressure
17 perspective.
18 During the last cycle we actually
19 implemented, our core designer recommended and it
20 turned out to be a very good recommendation, that for
21 the 100 rod patterns that we had, that we actually go
22 to a 120 rod pattern with a lower loading, so we had
23 eight assemblies that were of the OFA design that had
24 lower internal gas pressures. But that is the first
25 cycle margin issue is rod internal pressure. And it

1 requires that we actually put those OFA assemblies
2 that are limiting in lower power locations and do more
3 detailed fuel rod design.
4 MEMBER SIEBER: I presume you operate or
5 design the core with a low leakage pattern?
6 MR. VERDIN: That's correct.
7 MEMBER SIEBER: The assemblies that will
8 contain rods that operate at the bite level, I take it
9 all those will be new assemblies?
10 MR. VERDIN: I don't understand. Are you
11 referring to --
12 MEMBER SIEBER: You have some rods
13 inserted sort of partially?
14 MR. VERDIN: Yes, we maintain --
15 MEMBER SIEBER: So you can control it?
16 MR. VERDIN: We maintain control bank
17 delta very slightly inserted in the core. It's the
18 only thing --
19 MEMBER SIEBER: That would be all new fuel
20 assemblies?
21 MR. VERDIN: No. Actual delta will be OFA
22 fuel assemblies.
23 MEMBER SIEBER: All OFA fuel assemblies?
24 MR. VERDIN: That's correct.
25 MEMBER SIEBER: Okay.

1 MR. VERDIN: We're actually looking at
2 other things. It's really beyond up the uprate. It's
3 RCCA life. We're looking at potentially operating
4 control bank delta out of the core in the future;
5 something we're assessing.
6 MEMBER WALLIS: Now you need more boron to
7 control the initial reactivity? You need more boron
8 in the cooling system?
9 MR. VERDIN: Yes. The RCS boron will
10 increase slightly.
11 MEMBER WALLIS: All right. Does this have
12 any effect on the spent fuel pool, this new fuel?
13 MR. VERDIN: This fuel that we're putting
14 in is actually this 422 .422 inch rod design is
15 actually very similar to the fuel that we used in
16 cycles one through seven. We had Westinghouse standard
17 fuel.
18 MEMBER WALLIS: Yes.
19 MR. VERDIN: In cycle eight we
20 transitioned to another fuel vendor for a period of
21 time. The original fuel was .422 and from a
22 reactivity perspective it's actually -- it's been
23 assessed. It's in our current spent fuel for
24 criticality analysis this size of fuel rod with
25 enrichments up to five percent.

1 MEMBER WALLIS: You have a huge margin as
2 I understand anywhere in the spent fuel pool for
3 criticality.
4 MR. VERDIN: We have in our spent fuel
5 pool several regions. We have two regions that have
6 borated stainless steel racks that were installed in
7 1997. We have older regions that are borallex racks,
8 which are no longer accredited in the criticality
9 analysis. That requires credit for cellular boron.
10 We do that by checkerboarding. It's a burnout versus
11 years of decay pattern. But that's all been assessed
12 and it's bounded by the current standard fuel that's
13 in the spent fuel pool.
14 MEMBER SIEBER: You have a maximum limit
15 on new fuel enrichment based on your spent fuel pool
16 design, I take it?
17 MR. VERDIN: Yes. We do not exceed five
18 percent. Typically it's 4.95 with Westinghouse
19 uncertainties.
20 MEMBER SIEBER: And you will meet that
21 with all anticipated future core designs?
22 MR. VERDIN: We will not load a core with
23 higher enrichment than that.
24 MEMBER SIEBER: Okay.
25 MR. VERDIN: Okay?

1 MEMBER SIEBER: Thanks.

2 MR. VERDIN: As I mentioned, some of these
3 slides were obviously done because of the questions
4 that have come through, but this nine grid design is
5 based on the fuel proven seven grid design. The
6 balanced mixing vanes that I mentioned is a robust
7 feature. The increased dimple contact area are
8 designed to reduce wear rate and provide more margins
9 in the fuel assembly.

10 Another change that we're making is to
11 what's called tube and tube guide thimbles. This is
12 another robust fuel assembly feature that we're going
13 to be implementing in our fuel. This design is
14 actually a more rigid guide thimble that's designed to
15 -- it's actually simpler to manufacture than the
16 double dash pot, but it also provides additional
17 margin against burn up induced bowing that can cause
18 incomplete rod insertion in the fuel.

19 And I mentioned these other things, so
20 I'll continue.

21 I also mentioned the testing. This is not
22 all of the testing. I mentioned grid cross testing
23 and that sort of thing, but there is the FACTS loop
24 that was done to validate the hydraulics for the
25 assembly, the ΔTs, that sort of thing.

1 The VIPRE was the long term wear test of
2 the optimized fuel assembly adjacent to the 422V+
3 assembly. That was looking at things like cross flow
4 and wear. There's an extensive wear testing done in
5 this fuel assembly.
6 And lastly, the VISTA high-frequency
7 testing for the straps that I mentioned previously.
8 As far as the core design is concerned,
9 we've already discussed we will have two transition
10 core cycles that contain the OFA fuel assemblies. The
11 probably feed assembly quantities are listed. For the
12 first cycle, which is cycle 33 which will start in
13 November of 2006, we're anticipating 53 assemblies
14 will be required. There are 121 assemblies currently
15 and in the future in the Ginna core.
16 The 52 -- just because it's a 121 assembly core,
17 we have a center fuel assembly. So you can see when
18 you look at these numbers anywhere there's an odd
19 number means the center fuel assembly will be
20 replaced.
21 The first cycle 53, then we'll be doing 48
22 assemblies projected currently in cycle 34, which is
23 the second transition cycle. And then once we get to
24 the equil, all 422V+ cycles will basically be
25 oscillating between a 45 and a 44 assembly reload.

1 The 45, obviously, we'll be replacing the center
2 assembly every other cycle.
3 MEMBER SIEBER: I take it even though
4 you're using a type of low leakage loading pattern
5 that the overall, the fluence to the reactor vessel
6 will increase for the power uprate?
7 MR. VERDIN: Yes. The reactor fluence
8 will increase compared to previous low leakage core
9 designs.
10 MEMBER SIEBER: Okay.
11 MR. VERDIN: If you were to actually look
12 at things like outside of the vessel, the concrete,
13 the supports; the actual fluence that's leaving the
14 vessel is less than the original out/in fuel loading
15 fluence that's out there. So we still remain bounded
16 by the original plant analysis.
17 MEMBER SIEBER: Okay.
18 MR. VERDIN: Okay?
19 MEMBER SIEBER: That would have been my
20 next question.
21 MR. VERDIN: Okay.
22 MEMBER SIEBER: Thank you.
23 MR. VERDIN: All right. Lastly, as I
24 mentioned or was previously mentioned, the EPU
25 analyses were done for a range of temperatures from

1 564.6 to 576°F for our average RCS temperature.

2 The reload designs it has been decided, we

3 made this decision several months ago based upon the

4 turbine design and sensitivity information from the

5 vendor that we would use 574°F to satisfy the

6 requirements that Jim Dunne previously discussed.

7 Lastly, core operating limits. As was

8 previously mentioned, our axial power distribution

9 technical specification we'll be transitioning from

10 the constant axial offset control methodology to the

11 relaxed axial offset control methodology. The reason

12 for this transition, this was predominately done and

13 I'll put some figures up in a moment to show you what

14 it really means, we were concerned when we first

15 started on the uprate transition at the possibility of

16 a crud induced power shift situation. Similar has

17 occurred at several other Westinghouse plants.

18 Crud induced power shift is basically in

19 plants that have a very high massive operation rate

20 off he fuel. Can tend to actually concentrate boron in

21 the crud at the top of the core. It can suppress the

22 power distribution down. Has various challenges to

23 things like shutdown margin.

24 One of the challenges that we were

25 anticipating if we did get crud induced power shift

1 was the CAOC methodology that we currently have in our
2 tech specs really requires us to very tightly control
3 axial offset. If we do not control or if we cannot
4 control axial offset within the narrow band, we
5 basically get into what's called the accumulation of
6 penalty time due to the build in of abnormal Xenon
7 power distributions. Xenon and power distributions.
8 We were concerned the way our current tech
9 specs are if we accumulate one hour of penalty time,
10 that means if we cannot maintain it within this tight
11 band for one hour, we basically are forced to go below
12 50 percent power for 24 hours that allows you -- and
13 get back in the band and reestablish the correct Xenon
14 power distribution.
15 We were concerned because one of the
16 issues with crud induced power shift is during when
17 you do down power maneuvers, the boron tends to come
18 out of the crud and the power distribution then shifts
19 rapidly to the top of the core. It can actually
20 challenge your insertion limits on your rods to
21 maintain the flux down.
22 We were concerned at the time that we may
23 be subjected to CIPS and that we basically made this
24 as a mitigating strategy to help the operators and to
25 basically prevent this enforced -- tech spec enforced

1 down power.

2 What we have done, I have contacted

3 Kewaunee who is now near the end of this first uprate

4 cycle at 1772 megawatts thermal. They have seen no

5 evidence whatsoever of CIPS. So we're thinking that

6 the RAOC transition, obviously it still buys us

7 operational margin otherwise. But it appears that we

8 will not be inflicted with CIPS. And I really hope

9 we're not, because it will not be a nice issue to deal

10 with.

11 MEMBER SIEBER: Sounds like a hockey game.

12 MR. VERDIN: CIPS.

13 MEMBER SIEBER: In the penalty box.

14 MR. VERDIN: Yes. I can actually show you

15 that real quickly here. Just give me a moment.

16 MEMBER MAYNARD: Yes. I wouldn't be

17 overly optimistic until you actually operate it and

18 see it. Because I've been experienced with identical

19 plants, one having it and one not. A lot of it

20 depends on past chemistry, just a number of different

21 things that feed into that.

22 MR. VERDIN: Right. Right. We have

23 implemented some other changes. We have implemented

24 changes to our operating procedures to put the 60

25 gallon per minute let down orifice in service at the

1 time of any power changes.

2 One of the real reasons with CIPS is if

3 you actually look at the analytical methods that are

4 used to predict CIPS, they're not -- I don't have a

5 lot of faith in them. So basically our analyses said

6 that we originally said that we would not have or we

7 would be subjected to CIPS. Then the analysis said we

8 wouldn't. The difference was a small amount of carried

9 over crud that was used in the codes. It's really

10 something, I agree, you cannot say for sure that you

11 won't get it.

12 Just to give you a real quick -- if this

13 mouse works. This shows you just very briefly what the

14 difference is between the two methodologies.

15 On the left you see the constant axial

16 offset control methodology. You can see there's a

17 green line which represents a target line. It

18 represents really where the core wants to be at an all

19 rods out condition. Then you have two red lines plus

20 or minus five percent axial flux difference either

21 side.

22 We have to try to maintain flux between

23 those two red lines. If we get outside of the red

24 lines, we're basically into above 90 percent power,

25 the large black doghouse. You end up having to get

1 back in the red lines. There's no penalty time. It's
2 a tech spec requirement or you have to get below 90
3 percent power.
4 Below 90 percent you accumulate penalty
5 time anywhere between the black bounds and the red.
6 And if you're outside the black bounds, you're in
7 violation of the tech spec.
8 On the right you can see the relax axial
9 offset curve. You can see the doghouse now is really
10 your operating limits.
11 I've shown a green target line in there
12 still because it's important to understand that with
13 RAOC we're still going to operate according to the
14 CAOC methodology. So our operating strategy, the
15 operators will still have a target, we'll still want
16 them to maintain the axial flux difference on that
17 target line. It's just that now if they can't it due
18 to a CIPS type event, they can actually operate within
19 the larger bounds.
20 CHAIRMAN DENNING: How did you actually
21 perform this control to keep it within the target?
22 MR. VERDIN: The control is performed
23 basically during any type of a down power maneuver.
24 You are using rods and boron. So what it comes down to
25 is you have to basically balance what you're going to

1 use to keep the rods in a position to keep the flux
2 where you want them to be. So basically the control
3 is done by typically rules of thumb. We have rules of
4 thumb at power levels where the rods have to be for
5 various flux differences. We have recently
6 implemented more advanced codes within reactor
7 engineering that can help us do better predictions for
8 the operators for these vents.
9 MEMBER MAYNARD: I would assume that
10 typically for a down power maneuver reactor
11 engineering would be involved with how much rod versus
12 boron changes in order to maintain?
13 MR. VERDIN: That's correct. That's
14 typical. Our operators actually can use the rules of
15 thumb during rapid down powers when reactor
16 engineering is not in the control room. But, yes,
17 typically we would be involved for any planned down
18 power.
19 Okay?
20 Core operating limits. As I mentioned, the
21 CAOC to RAOC transition. One other things about CAOC
22 to RAOC is that we are really trading off analysis
23 margin for operating margin. So in reality when you're
24 operating at your RAOC limits, you are more limiting
25 than you would be during CAOC. That's obviously a

1 decision to really make that tradeoff, basically to a
2 much more complicated analysis in order to provide
3 yourself with additional operating margin.
4 There are no changes to the thermal design
5 flow for the core. The actual volumetric flow, it's
6 been already said, that it will increase marginally.
7 This fuel assembly does have a lower overall pressure
8 drop.
9 The actual -- Mark mentioned previously as
10 well, the mass flow does decrease slightly. That's
11 just due to density changes.
12 The nominal 100 percent rate of thermal
13 power, heat flux hot channel factor will increase from
14 its current limit of 2.45 to 2.6. This 2.45 currently
15 is because of PCT and the SECY LOCA method that we
16 have right now. The 2.45 limit was established for
17 the new best estimate LOCA with automated statistical
18 treatment of uncertainty methodology. Does support the
19 change to 2.6 and all the non-LOCA analyses do as
20 well.
21 The nominal 100 percent enthalpy rise hot
22 channel factor will be decreasing slightly from 1.75
23 to 1.72 in the 422V+ fuel. This is one of those margin
24 recovery things. Obviously, with the higher powered
25 fuel, we go to a larger diameter rod, we also bring

1 down the F Δh to improve DNBR margin.

2 The optimized fuel assemblies themselves

3 will have a lower limit due to the transition core

4 penalties. When you put this lower hydraulic

5 resistent fuel assembly next to the older OFA higher

6 hydraulic, what you can do is you'll actually do have

7 cross flow from the higher resistance assembly into

8 the lower resistance assembly. As a result, the OFA

9 limits have to be lower.

10 And the last thing is the shutdown margin

11 requirements that we have will be reduced. Mark

12 mentioned previously the addition the of a new

13 feedwater isolation valve. That feedwater isolation

14 valves allows us to, in the event of a normal feed reg

15 valve closure failure, that normally closes in 10

16 seconds. Currently the feed pump discharge closes in

17 60 seconds. That tends to lead to more water being

18 pushed into the steam generators. The required higher

19 shutdown margin with the current design in order to

20 limit the mass and energy release rate and the return

21 to power. So our shutdown margin requirements will be

22 reduced to 1300 pcm from current end of cycle of 2400

23 pcm.

24 MEMBER MAYNARD: So which one of these are

25 you taking credit for in your analysis? Is it the

1 main feed isolation in 30 seconds or the feed reg
2 valve in ten seconds?
3 MR. VERDIN: We do not credit the feed reg
4 valve. It is the -- Mark might be able to add more to
5 this. But the ten second closure of the feed reg valve
6 is the one that we would expect to occur. The 30
7 second is what we actual credit the analysis.
8 MR. FINLEY: Gordon, this is Mark Finley.
9 Gordon is speaking of the limiting
10 analysis. We credit both in the safety analysis, both
11 the feed regulating valve and the new feed water
12 isolation valve. But for a failure, we have to
13 consider single failure of that feed regulating valve,
14 the faster stroking valve. In that case in that
15 analysis we take credit for the new actuator closing.
16 MEMBER MAYNARD: Okay.
17 MR. FINLEY: Okay.
18 MR. VERDIN: And I'm going to introduce
19 Mark Finley again who was just up here. He's the
20 project director again. He's going to be discussing
21 safety analysis.
22 CHAIRMAN DENNING: That will be after the
23 break.
24 And are there any questions on the core
25 before we move on? Okay.

1 In that case we will now take a 15 minute,
2 which means that we'll start up again at 10:20
3 (Whereupon, at 10:04 a.m. off the record
4 until 10:20 a.m.)
5 CHAIRMAN DENNING: Proceed please.
6 MR. FINLEY: Okay. Thank you.
7 Mark Finley. I mentioned that I was in the
8 safety analysis group at Calvert Cliffs. That does not
9 make an expert in the Westinghouse safety analysis
10 methodology, little different from combustion
11 engineering methodology under Westinghouse. But I do
12 have the experts or a representation of the experts
13 from Westinghouse in the audience. So if you have
14 questions that go beyond my knowledge, I won't
15 hesitate to call on them.
16 What I'd like to talk about is the changes
17 to the safety setpoints. I mentioned under the license
18 amendment section that there were various safety
19 setpoints that are changing. I'll talk about those.
20 I'll also talk about the control setting
21 changes.
22 Talk about the methods that are changing
23 in the safety analysis area.
24 And then I'll talk about results from
25 LOCA/non-LOCA containment and dose assessment and

1 provide a conclusion.

2 First, the safety setpoints that are

3 changing. These are the setpoints in the technical

4 specifications. I'll go down the list briefly here. If

5 you have questions stop me.

6 For the high flux trip we are reducing

7 that.

8 Oh, by the way, these are the analytical

9 setpoints, i.e, the setpoints that Westinghouse would

10 use in their safety analysis. The actual field

11 settings are bounded by these analytical setpoints.

12 But the analytical setpoint is being reduced three

13 percent. And what that does is provide us a more

14 responsive high flux trip for certain of the over

15 power transients.

16 Both the steam line hi-hi isolation and

17 the steam line hi isolation settings, which are based

18 on steam flow, are being increased. And that

19 incorporates or allows us to increase our steam flow.

20 The limiting safety setting for the lift

21 setting for the pressurizer safety valves is being

22 reduced by two pounds from 2544 psig to 2542 psig.

23 Essentially driven by also load analysis. I'll talk

24 about those results in a second.

25 MEMBER WALLIS: You can actually set it as

1 accurately as that?

2 MR. FINLEY: The tolerance in our setting

3 of the safety valves is plus or minus one percent.

4 And --

5 MEMBER WALLIS: One percent on -- a change

6 of 2 psig is within your tolerance?

7 MR. FINLEY: That's correct. The actual

8 field setting is more than one percent below this

9 analytical limit. So we incorporate the field setting

10 tolerance under the analytical limit.

11 The next two set points actually were not

12 required for EPU, but again similar to the setting we

13 discussed previously. Because we were redoing the

14 analysis for EPU, we wanted to get some additional

15 margin to support instrument uncertainty calculations.

16 But we are reducing the safety injection setting on

17 the pressurizer pressure from 1715 psig to 1700 psig.

18 We've incorporated that in the LOCA analysis.

19 And similarly, although in the opposite

20 direction, we're increasing the containment spray

21 setting from 32.5 psig to 33.4 psig. Small change.

22 Again, that one pound margin is utilized in our

23 uncertain analysis.

24 And lastly --

25 MEMBER WALLIS: And what's your

1 containment design pressure?

2 MR. FINLEY: I'll show that on the

3 subsequent slide. The containment design pressure is

4 60 psig.

5 Finally. the P-8 permissive setpoint,

6 which is the setpoint above which you'll have a

7 reactor trip on low flow, has been reduced from 50

8 percent to 35 percent. One of the reasons for the

9 fairly size change here is we're using the updated and

10 more conservative methodology from Westinghouse to

11 establish this permissive setpoint.

12 With respect to the control settings,

13 these are the control systems, the most significant

14 control systems that are fed into the safety analysis.

15 The full power and zero power setting for pressurizer

16 level, at the top there you see there 56 percent for

17 the full power setting. Twenty percent for the zero

18 power setting. That's an expansion of the range

19 compared to what we have now, 50 and 35. However,

20 these ranges that we're going to for EPU are very

21 similar to what we had prior to replacing the steam

22 generators. As you recall, we mentioned back in 1996

23 we actually had an average coolant temperature that's

24 very close to what we'll have for EPU. And the program

25 level in the pressurizer was essentially the same as

1 well. So we're going back to that control regime.

2 Average coolant temperature, we talked

3 about --

4 CHAIRMAN DENNING: Now help me again on

5 the pressurizer level. What happens at 56 percent? Is

6 that a trip.

7 MR. FINLEY: Okay. No. This is actually

8 the steady state control level. So this would be the

9 nominal expected level at full power, 56 percent in

10 the pressurizer.

11 CHAIRMAN DENNING: Oh, I'm sorry. I see.

12 MR. FINLEY: And then as you come down in

13 power in a controlled fashion, the pressurizer level

14 would program down as well.

15 Average coolant temperature mentioned, 574

16 for full power, ramp down to 547 at zero power. That's

17 the same zero power setting as what we had previously.

18 We have reduced the gain setting for rod

19 control on a power mismatch. We typically operate in

20 automatic rod control. And if you have a power

21 mismatch setup beyond a certain point, you'll drive

22 the rods. We actually reduced the sensitivity, if you

23 will, on this system so that they won't drive as fast

24 or as far on a given power mismatch. And that was

25 actually driven by rod drop analysis in the safety

1 analysis.

2 MEMBER SIEBER: Do you find running in

3 automatic for rod control gives you a lot more rod

4 motion than if the operator did it manually between

5 elements that you had administratively set?

6 MR. FINLEY: Yes. I'm going to defer to

7 Roy Gillow, our operations expert, to answer that.

8 MR. GILLOW: No, we really don't have any

9 rod shattering type problems or typically we don't get

10 any steps at all in the automatic rod control at stay

11 state or close to stay state. We've had some hot leg

12 streaming issues, and that isn't enough to give us a

13 rod motion even.

14 MEMBER SIEBER: Thank you.

15 MR. FINLEY: With respect to steam dump

16 modulation, one of our objectives throughout the

17 analysis was to maintain the Ginna capability to ride

18 out a 50 percent load rejection, a fairly sizeable

19 power mismatch from our design perspective. And to do

20 that we needed to essentially increase the response

21 for the steam dump system. So as you can see here the

22 temperature range over which the steam dumps would

23 fully modulate has been reduced as far as the power

24 mismatch is concerned. And that just makes that steam

25 dump system more responsive to a load rejection.

1 and then finally one of our instrument
2 modifications which we think will provide benefit with
3 respect to operating margin is we're incorporating a
4 4.5 second time delay filter on our T_{Hot} indication
5 and what that does is dampen out the oscillations that
6 we see in T_{Hot} which are common to Westinghouse and
7 other pressurized water reactors. You see some
8 oscillation in the T_{Hot} indication just due to
9 incomplete mixing as the hot water comes out of the
10 different power level assemblies, you see different --
11 it's a hot leg streaming issue that Roy mentioned.
12 We do have some oscillations there. This
13 filter will damper those oscillations and actually
14 provide a stable response for the operators.
15 MEMBER SIEBER: That also though increases
16 the uncertainty of the measurement, does it not?
17 MR. FINLEY: We factor this module in the
18 loop uncertainty calculation, that's correct. We also
19 factor in the time delay in the analysis as well. In
20 other words, we model this as an appropriate time
21 delay in the response.
22 MEMBER SIEBER: And the time delay, I take
23 it, is in the range of one to two seconds?
24 MR. FINLEY: The time delay is in the
25 range of 4.5 seconds, right? And that's defined that

1 the .693 RC sort of time frame for the circuit.

2 MEMBER SIEBER: All right. Thank you.

3 MR. FINLEY: With respect to methods, I

4 list the primary methods here. There are other

5 methods--

6 MEMBER WALLIS: And someone is going to

7 explain to me later on how ASTRUM works?

8 MR. FINLEY: Actually, we can take that

9 opportunity right now. We'll start off by saying for

10 the large break LOCA we are changing the methodology

11 h ere. And this again was a license amendment because

12 this method is listed in the technical specifications

13 going from an older version of the BE LOCA methodology

14 to the newest BE LOCA/ASTRUM method. And let me ask

15 Jeff Kobelak from Westinghouse to discuss the new

16 method.

17 MEMBER WALLIS: There's no medium break

18 LOCA involved here?

19 MR. KOBELAK: No. The ASTRUM is still a

20 large break LOCA and --

21 MEMBER WALLIS: Well, I mean there's

22 another table here, it says large and small. There's

23 nothing in between?

24 MR. KOBELAK: No. The large break covers

25 down to a one square foot break.

1 MEMBER WALLIS: And then small is less
2 than that?
3 MR. KOBELAK: I can't speak to the small
4 break LOCA analysis.
5 MR. MILANO: And the answer is yes.
6 MR. KOBELAK: Yes.
7 MEMBER WALLIS: Yes. So there isn't any
8 subdivision into small, medium and large? Okay.
9 MR. KOBELAK: What the ASTRUM methodology
10 is, it's built off of our prior 1996 best estimate
11 LOCA methodology. And what we do is we have a set of
12 reference transient conditions, which is essentially
13 the nominal operating conditions for the plant. At
14 that point we will run a set of confirmatory studies
15 to determine what the limiting steam generator tube
16 plugging level is, the limiting vessel average
17 temperature. We run several Cobratec cases at both the
18 high Tavg and the low Tavg window and we determine
19 what the limiting case is. And we take these cases
20 into our uncertainty analysis. And essentially what we
21 do is we will randomly sample from all the different
22 uncertainty parameters and we'll run 124 Cobratec
23 cases from all these randomly sampled parameters. And
24 then we determining the limiting PCT and oxidation
25 values from the 129 Cobratec cases.

1 CHAIRMAN DENNING: Give us an idea of what
2 variables are considered uncertain and for which you
3 have density functions. And what are the variables
4 that are considered conservatively, taken at a
5 conservative value?
6 MR. KOBELAK: Okay. The parameters that
7 are bounded would be the steam generator tube plugging
8 level. The vessel average temperature we bound based
9 on the nominal windows. So we will run several cases
10 at the 576 and several cases at the 564. And then we
11 also sample and uncertainty around what the limiting
12 value is from the window.
13 The average power in the low power
14 assemblies is a bounded parameter. And loss of offsite
15 power versus offsite power available is a bounded
16 parameter.
17 In the uncertainty sampling we will sample
18 accumulator water volume, accumulator pressure,
19 accumulator temperature, safety injection temperature,
20 the peaking factors. And on top of that we will also
21 sample the local parameters, blow down heat transfer
22 multiplier, reflood heat transfer multiplier. So those
23 would all be sampled within the 124 Cobratec cases.
24 MEMBER SIEBER: It seemed to me that
25 Westinghouse at one time had a methodology that said

1 for a given class of plants there was a broad accident
2 analysis that fit plants in that category. and that if
3 your parameters fit within certain defined limited,
4 you didn't need to rerun the full blown LOCA analysis.
5 Is my memory correct on that?
6 MR. KOBELAK: For this particular case we
7 redid the entire LOCA analysis.
8 MEMBER SIEBER: Okay.
9 MR. KOBELAK: I honestly can't speak to
10 what we've done.
11 MEMBER SIEBER: So that happened 10 or 15
12 years ago?
13 MR. KOBELAK: Yes.
14 MEMBER SIEBER: Apparently I can't either.
15 But it seemed to me there was a lot of parameters that
16 were variable parameters in here like, you know, it
17 was the multitude of tens of parameters that are
18 important in the analysis.
19 MR. KOBELAK: Yes. In the ASTRUM analysis
20 we sample, I believe it's 38 different parameters --
21 MEMBER SIEBER: Right.
22 MR. KOBELAK: Using the Monte Carlo
23 method.
24 MEMBER SIEBER: Okay.
25 CHAIRMAN DENNING: And what are the

1 fundamental differences between that and the SECY 83
2 472?
3 MR. KOBELAK: In the SECY analysis there
4 was a lot of parameters that we would bound rather
5 than sample uncertainties around them, we would use a
6 limiting peaking factor. In ASTRUM we only determined
7 four bounded parameters from these conformity studies.
8 And everything else is run at a nominal value. And
9 then we do the uncertainty sampling afterwards.
10 CHAIRMAN DENNING: So that there is the
11 complete mixing together of what we would call
12 epistemic and aleatory uncertainties here? Both types
13 of uncertainties are treated in a probabilistic manner
14 rather than looking at a particular worse state of the
15 plant. And then from that worse state of the plant,
16 from an aleatory version seeing what's the uncertainty
17 in the best estimate?
18 MR. KOBELAK: Yes. We will only bound
19 those four particular parameters and then the rest of
20 them are all sampled.
21 CHAIRMAN DENNING: And the Staff has
22 accepted this approach? Is that true? Has this been
23 reviewed and this approach has been accepted?
24 MR. NAKOSKI: Yes. This is Jim Nakoski.
25 I'm the PWR Systems Branch Chief.

1 And the answer is ASTRUM has been reviewed
2 and approved by the Staff.
3 MEMBER WALLIS: Is the break size one of
4 these random variables?
5 MR. KOBELAK: Yes. For double ended
6 guillotine breaks we will sample a discharge
7 coefficient. For split breaks we will sample a
8 discharge coefficient and the break size.
9 MEMBER WALLIS: But you sample the size
10 itself?
11 MR. KOBELAK: Yes, we sample the break
12 size as well.
13 MEMBER WALLIS: So the break sizes are
14 random input?
15 MR. KOBELAK: Yes. The break size and the
16 discharge coefficient are randomly --
17 MEMBER WALLIS: And you have some kind of
18 a probabilistic assessment of the probability of these
19 various break sizes then?
20 MR. KOBELAK: We do not factor that into
21 the LOCA analysis.
22 MEMBER WALLIS: So it's a flat, they're
23 all equally likely?
24 MR. KOBELAK: Yes.
25 MEMBER WALLIS: That's --

1 CHAIRMAN DENNING: Well, you said you
2 didn't factor that in, but your answer was you did but
3 with a flat answer?
4 MR. KOBELAK: Well, yes. We sampled them
5 all at an equal probability. We don't --
6 MEMBER WALLIS: An equal probability?
7 MR. KOBELAK: Yes.
8 MEMBER WALLIS: Which is really presumably
9 conservative. Large break is less likely than a medium
10 break?
11 MR. KOBELAK: Yes.
12 MEMBER WALLIS: And they're all given
13 equal probability?
14 MR. KOBELAK: Yes. There's a 50/50 percent
15 change of whether it will be a guillotine break or
16 split break.
17 MEMBER WALLIS: No, but I know. But size,
18 the size?
19 CHAIRMAN DENNING: And when you say the --
20 MR. KOBELAK: And the --
21 MEMBER WALLIS: When you've a size range
22 of, I don't know, one square foot up to however many
23 it is, the maximum--
24 MR. KOBELAK: Yes, and we -- that is --
25 MEMBER WALLIS: Do you sample flat in that

1 range?

2 MR. KOBELAK: Flat, yes.

3 CHAIRMAN DENNING: Why did you consider

4 that to be conservative, Graham? Don't forget, we're

5 not looking at probabilities here. This isn't the

6 PRA. This is saying that probably is the less

7 challenging LOCA at one square foot has equal

8 likelihood to the most challenging so that your --

9 MEMBER WALLIS: No. But then the

10 consequences depend on the size of the break, as I

11 understand it. And so if you happen to just randomly

12 get large break LOCAs, you're going to get higher

13 temperatures in your output. Whereas, in reality

14 there's -- in reality? According to expert

15 elicitation the large break LOCA is considerably less

16 likely than the one square foot. The largest break is

17 significantly less likely than a one square foot

18 break. And I think what some other people have done

19 is to actually put in a more realistic probability

20 distribution for the size of the break.

21 And this I think is conservative. This

22 comes out with more large break LOCAs as inputs than

23 is realistic.

24 CHAIRMAN DENNING: I would disagree.

25 MEMBER WALLIS: Or more of the largest

1 break.

2 MR. FINLEY: Certainly from a regulatory

3 standpoint all the breaks need to show a PClad

4 temperature less than 2200 degrees Fahrenheit.

5 CHAIRMAN DENNING: All of those do you're

6 saying?

7 MR. KOBELAK: All of it.

8 CHAIRMAN DENNING: So you take a large

9 break and for that one you determine what the --

10 MEMBER WALLIS: No.

11 CHAIRMAN DENNING: That's what --

12 MEMBER WALLIS: Large breaks is a spectrum

13 break, as I understand it.

14 CHAIRMAN DENNING: Right.

15 MEMBER WALLIS: It's not as if large break

16 is the biggest break.

17 CHAIRMAN DENNING: No. I meant the biggest

18 break. You take the biggest break and demonstrate for

19 that one or are you treating that probabilistically so

20 that --

21 MR. KOBELAK: We will take the results of

22 all those 124 runs across the break spectrum and we

23 will show that the most limiting of all of those is

24 still less than 2200.

25 CHAIRMAN DENNING: You don't use the

1 statistical --

2 MEMBER WALLIS: Yes. That is the

3 statistical. Let's get it straight. There are two

4 ways to do this.

5 CHAIRMAN DENNING: Yes.

6 MEMBER WALLIS: You can say we're going to

7 take breaks of say, 1, 2, 3, 4, 5 categories, right,

8 of sizes?

9 CHAIRMAN DENNING: Yes.

10 MEMBER WALLIS: And we're going to run

11 statistics on one and get a number. Statistics on two

12 and get a number. Statistics on three. And then we're

13 going to look at the biggest number of PCT we get out

14 of these six categories.

15 The other to do it is to put in all of

16 these breaks into the statistics.

17 CHAIRMAN DENNING: Then that --

18 MEMBER WALLIS: Then you may randomly

19 never get the biggest break possible at all. It may

20 just happen that you'd never get that.

21 CHAIRMAN DENNING: Oh, you mean in the

22 sampling?

23 MEMBER WALLIS: In the statistical process

24 you may never hit the biggest break, doubled ended --

25 CHAIRMAN DENNING: In a statistical

1 sampling? Well, you'd probably sample in such a way
2 that your forced --
3 MEMBER WALLIS: Well there's a good
4 probability of it, but you're not sure you'll get
5 that--
6 CHAIRMAN DENNING: Well, you'd probably do
7 that in a structured way like sampling where you --
8 MEMBER WALLIS: Well, I think I know what
9 you've done. You have used the break size as an input
10 statistical parameter. Just like these other things
11 with the correlations and --
12 MR. KOBELAK: Yes. Exactly. That's one
13 of the sample parameters similar to it.
14 MEMBER WALLIS: And then I can talk with
15 my colleague about what it means at some other time.
16 MEMBER SIEBER: It seems to me the issue
17 is you've got a lot of parameters that you want to
18 vary. And if you ran a case for all 34 parameters at
19 its limits, we wouldn't be here; you'd still be
20 running your computer code. I mean, that's thousands
21 of cases. So this is a reasonable way to cut down the
22 number of runs that you have to make to still define
23 an envelop in which you can operate safely. That's
24 sort of my way of looking at it.
25 MEMBER WALLIS: Well, they're using a

1 statistical something out there with a certain
2 confidence that they've got if they covered the
3 certain range of the probabilistic space. And if they
4 run this code on Tuesday, they may get a different
5 answer than they get on Monday using exactly the same
6 method.
7 CHAIRMAN DENNING: Now is the criterion
8 for being satisfied is that every one of these cases
9 as to be below the --
10 MEMBER SIEBER: The 2200.
11 CHAIRMAN DENNING: -- 2200? It's not the
12 95th percentile or something like that?
13 MR. KOBELAK: Right. It's that all of
14 these cases will be less than 2200. All of these
15 cases will be less than 17 percent oxidation.
16 MEMBER WALLIS: Based on a 95/95?
17 MR. KOBELAK: Yes.
18 MEMBER WALLIS: All right. And if you
19 wanted to take the second one, you'd have to take 295
20 or something --
21 MR. KOBELAK: Yes. The 124 is enough to
22 assure that we will find at least the 95/95 PCT and
23 oxidation. And for each additional parameter that you
24 would be looking for, then the number increases.
25 MR. CARUSO: If you run your cases on

1 Monday and you get an answer where one of them exceeds
2 2200, what do you do? Do you just run it again on
3 Tuesday and if it's okay, you accept Tuesday's results
4 and throw away Monday's?
5 MR. KOBELAK: No. Whenever we run the
6 code to determine the sampling and develop these 124
7 cases, once we've run that code we will maintain that
8 seed. So if we were exceed 2200 from that analysis,
9 we would have to find ways of reduced peaking factors,
10 some way to meet that limit. We would not resample.
11 MEMBER WALLIS: It would be very
12 interesting if the government ran confirmatory
13 analysis and it doesn't matter whether it's Monday,
14 Tuesday or Wednesday. It's just that since they
15 sample differently, they get a different number. IF
16 they get a number which is 2200 and one and you get a
17 number which is 1999, it would be interesting to see
18 what they would do.
19 MR. KOBELAK: Yes. Fortunately, we didn't
20 challenge the limits with this analysis.
21 MEMBER WALLIS: But you seemed to come up
22 with an 1800 and something number. It's not as if
23 you're sort of near the limit, as I understand.
24 MR. KOBELAK: Yes. The 1870 was the
25 limiting case we had.

1 MR. FINLEY: Okay. Thanks. Thanks, Jeff.

2 With respect to the small break

3 methodology, no change in that methodology. Continue

4 to use the NOTRUMP method from Westinghouse.

5 For the non-LOCA events we have gone to

6 the updated methodology, the RETRAN methodology for

7 the system code. Presently we use LOFTRAN for these

8 non-LOCA events.

9 For the control system transients we

10 continue to use LOFTRAN both now and for EPU.

11 For the containment analysis we currently

12 use the GOTHIC methodology, although a slightly older

13 versions of what was used by Westinghouse for the

14 updated EPU containment analysis.

15 For steam line break we currently use

16 COCO, that's being updated to the GOTHIC methodology.

17 And finally, for dose assessment we did et

18 the alternate source term methodology approved last

19 year and we just updated that for the EPU source term.

20 MEMBER SIEBER: And those, the dose to

21 control operators, it seemed to me come out pretty

22 low, right? It's in the two or three rem range?

23 MR. FINLEY: Well, we'll show you the

24 results for the control room in a few slides.

25 MEMBER SIEBER: Okay.

1 MR. FINLEY: Okay. What I tried to do on
2 this slide is capture the most significant of the non-
3 LOCA events. I think this speaks to some extent to the
4 questions or comments that came up early on with
5 respect to margin.
6 I would like to say at the outset that
7 obviously these methods are conservative. They're
8 approved methods. As well the inputs to the methods
9 are also conservative and bounding.
10 And finally, the acceptance criteria that
11 you see here are conservative. So there's margin in
12 these results, although it appears they're close to
13 the acceptance criteria.
14 To summarize, I've grouped these in four
15 categories. Overheating as a result of reduced
16 primary cooling being the first.
17 MEMBER WALLIS: Could we look at these
18 now? These seem to be important numbers?
19 MR. FINLEY: Yes.
20 MEMBER WALLIS: And it looks as if in
21 every case your result is very close to the criteria?
22 MR. FINLEY: Yes. Yes. And as I said,
23 there's conservatism in the methods and in the inputs
24 and in the criteria. In addition, when we did these
25 analyses, our objective was not to demonstrate how

1 much margin we had to the acceptance criteria. Our
2 objective was to demonstrate that we meet the
3 acceptance criteria.
4 MEMBER WALLIS: Well, you seem to have
5 very carefully engineered this plant so that it's
6 close to the envelop in a lot of different dimensions
7 here.
8 MR. FINLEY: Well, in some sense that's
9 true. In other words if we made changes to inputs
10 into these methods, we typically would stop at
11 something that would give us an acceptable result, and
12 that's why you see the results that you see here.
13 MEMBER WALLIS: And then we may have some
14 concern when you say things are conservative about
15 just what you mean and how much the uncertainty is
16 some of these numbers. We really dug into this.
17 MR. FINLEY: Yes. I understand. Let me
18 give you an example. In fact, I'll call upon Chris
19 McHugh from Westinghouse here.
20 But take the first loss of flow condition
21 2 event, for example. We show the DNBR acceptance
22 criteria here for DNBR at 1.38 and we calculated
23 1.385, but that looks very close to the limit. There
24 is margin in that 1.38 acceptance criteria for the
25 DNBR limit. And let me ask Chris McHugh to speak to

1 that just as an example.

2 MEMBER WALLIS: Well this 1.385, does that

3 come from the mean of some best estimate? There's no

4 uncertainty put on that number for me.

5 MR. McHUGH: This is Chris McHugh from

6 Westinghouse.

7 That's the actual calculated out of RETRAN

8 or out of --

9 MEMBER WALLIS: But RETRAN isn't that

10 accurate a code, is it? I mean, this could easily be

11 plus or minus something or other. I don't know how big

12 it would be. But if that's the number that RETRAN

13 gives you, there's a plus or minus on that which is

14 not insignificant, is it?

15 MR. FINLEY: Well, this of course gets

16 back to the thermal hydraulic methodology as well,

17 which is essentially a 95/95 type methodology --

18 MEMBER WALLIS: Is it? I mean is this

19 1.38 a 95/95, it isn't, is it? Isn't it just one

20 point from RETRAN code?

21 MR. FINLEY: With respect to the thermal

22 hydraulic analysis this does incorporate variations in

23 power, temperature and flow.

24 MEMBER WALLIS: Please, now I want to be

25 clear. Is this treated the same way as the LOCA, this

1 is 1.35 number as with the 124 or whatever the number
2 of runs is?
3 MR. FINLEY: No.
4 MEMBER WALLIS: No, it isn't?
5 MR. FINLEY: That's a single bounding run.
6 MEMBER WALLIS: It's one run? And we know
7 that these codes aren't all that accurate. They have
8 correlations and things in them which do not represent
9 data perfectly. They have assumptions in them. And
10 they have simplifications and --
11 MR. McHUGH: Well, the correlation
12 uncertainties are accounted for in the DNBR limit.
13 The actual limit that he has listed there of 1.38, the
14 actual limit for the 14 by 14 422V+ fuel is 1.24.
15 MEMBER WALLIS: So you're saying that the
16 Agency accounts for correlations in the way it
17 specifies the criteria it accounts for uncertainty in
18 correlations in the way it --
19 MR. McHUGH: Yes.
20 MEMBER WALLIS: So when it approves RETRAN
21 it's implying that it knows that RETRAN has
22 uncertainty within the limits that were considered in
23 setting the criteria?
24 MR. McHUGH: Well, it approved RETRAN with
25 the methodology that we planned to use RETRAN with. It

1 wasn't just the RETRAN code by itself. But then that
2 methodology was used for --
3 MEMBER WALLIS: But then when you change
4 the plant, the errors may change. So you're sort of
5 assuming that your assessment of uncertainties in
6 RETRAN before the uprate haven't changed in any way
7 with the uprate?
8 MR. MIRANDA: I didn't understand the
9 difference between the criteria and that' identified
10 here, 1.38 and what you said the actual criterion is?
11 What did you mean? Whose criterion is this and what
12 did you mean by the --
13 MR. McHUGH: The DNB correlation that we
14 used has a limit of 117. From 1.17 to 1.24 they --
15 MR. MIRANDA: I'm sorry. You said it has
16 a limit. What do you mean by it has a limit?
17 MR. McHUGH: The approved limitation of
18 the correlation is 1.17. We can't go below that.
19 Because, like you said, there are uncertainties
20 associated with the correlation. It's not perfect.
21 And then we used the revised thermal
22 design procedure, which means we statistically
23 convolute the uncertainties into the DNBR limit, and
24 that takes the limit from 1.17 up to 1.24?
25 MEMBER WALLIS: So that it's the Agency

1 that's convoluting the uncertainties?

2 MR. McHUGH: Pardon me?

3 MEMBER WALLIS: It's the Agency? You're

4 speaking for the --

5 MR. McHUGH: No. The vendor takes the --

6 the Agency gave us 1.17.

7 MEMBER WALLIS: Oh, so I don't understand

8 this. So what's the law, let's say the law laid down

9 by the governmental agency is 1.17?

10 MR. McHUGH: Well, yes. For the DNB

11 correlation that we used, that's --

12 MEMBER WALLIS: Well, maybe that's what we

13 should be looking at.

14 CHAIRMAN DENNING: Just for the

15 correlation.

16 MEMBER WALLIS: So you have taken the kind

17 of uncertainties in changing the criteria from some

18 regulatory value to some other value?

19 MR. McHUGH: To a higher more restrictive

20 value.

21 MEMBER WALLIS: It seems a strange way of

22 doing it. I would think you would take your

23 predictions and show that you meet some regulatory

24 criterion specified by the government. Wouldn't that

25 be the 1.17

1 MR. MIRANDA: This is Sam Miranda from the
2 NRC.
3 We don't have a specific value like 1.17.
4 The law says there should be a condition two event,
5 for example, that there should be no fuel clad damage.
6 And the 1.17 is determined by DNB experiments and
7 correlations to come with a value that with good
8 confidence will assure that there's no clad damage.
9 And then what Chris is talking about is
10 adding on to the uncertainties they could either be
11 put in directly or convoluted in to assure that you
12 have this 95/95 confidence level that no clad damage
13 will occur.
14 So you start with a 1.17 and by the time
15 the uncertainties are added in, the limit, the safety
16 analysis limit that the analysis have to meet, is
17 9.38.
18 MEMBER WALLIS: Then you make one RETRAN
19 run with 1.385?
20 MR. MIRANDA: Well, in this case it's
21 RETRAN, it was VIPRE.
22 MEMBER WALLIS: So this is very different
23 from what we just heard from Westinghouse. They make
24 124 runs and then they compare a fixed criteria. And
25 you're sort of stretching the criterion first and then

1 making one run. That seems a strange way to do it.

2 MR. MIRANDA: Yes, this is not a best

3 estimate calculation. These are conservative

4 calculations. And the conservatisms are added, for

5 example, in the initial conditions that are used in

6 calculating the transient with RETRAN. And then the

7 results from RETRAN are factored into a more detailed

8 core model in VIPRE which actually calculated the DNB

9 ratio.

10 MEMBER WALLIS: It seems that in order to

11 satisfy ourselves you're doing the right thing. We

12 ought to maybe spend a lot of time on these sort of

13 things rather than just reading an SER which says they

14 meet the regulation. Because how they meet the

15 regulations is absolutely critical.

16 MR. MIRANDA: Well, these things have been

17 addressed in detail in the past --

18 MEMBER WALLIS: It doesn't concern me. I

19 want to be satisfied now.

20 MR. MIRANDA: I will --

21 MEMBER WALLIS: If you would point me to

22 the reference, if there's something that I can study

23 and be convinced, that's fine. But the fact that

24 someone's done it before doesn't necessarily I'm

25 happy.

1 MR. MIRANDA: Well, the licensing basis--
2 MEMBER WALLIS: I want to know what you're
3 doing and why and what's the rationale for deciding
4 everything is okay.
5 MR. MIRANDA: Yes. These methods have not
6 changed from the licensing basis. In the EPU they
7 used the same sort of treatment of uncertainties.
8 MEMBER WALLIS: So when they did it
9 before, before the EPU, did they use 1.38 or some
10 other number?
11 MR. MIRANDA: It could be any number,
12 actually. It depends on the plant, it depends on the
13 correlation used. And for this case it was a WRB-1
14 correlation.
15 MEMBER WALLIS: So what did they use
16 before the EPU for these numbers? What did they use
17 for this 1.38 before the EPU?
18 MR. McHUGH: I believe it was 1.38.
19 MEMBER WALLIS: It's the same thing?
20 MR. McHUGH: I'm not positive. I'd have
21 to go back and check.
22 MEMBER WALLIS: And then the result,
23 1.385, did that change with the EPU?
24 MR. McHUGH: Yes.
25 MEMBER WALLIS: And what was it before?

1 MR. McHUGH: It was about 1.6 before.

2 MEMBER WALLIS: 1.6? So this looks as if

3 they've moved very close to some limit as a result of

4 the EPU? Should I conclude that?

5 MR. McHUGH: Yes.

6 MR. MIRANDA: Yes.

7 MEMBER WALLIS: If they got 1.375, you

8 would have rejected the application?I

9 MR. MIRANDA: Personally if they had got

10 1.375, I would have questioned it.

11 MEMBER WALLIS: Well, I could ask that of

12 all these numbers. When get to ATWS there's 3200,

13 which is presumably -- is that an ASME limit or

14 something for the 3200 or is that something that's

15 varied in the same way that the 1.38 was varied?

16 MR. MIRANDA: Actually, the 3200 psi limit

17 is the ASME level C stress limit --

18 MEMBER WALLIS: Which is something which

19 is not subject to be twiddled?

20 MR. MIRANDA: Right. Well, it can be

21 twiddled in the sense that it's the weakest component

22 in the RCS.

23 MEMBER WALLIS: And then when I look at

24 3.93, does that have uncertainties in it, 3193? Is

25 that a very conservative number or is that a mean, or

1 95/95, or what is it?

2 MR. MIRANDA: That number actually is less

3 conservative than the other accident analysis, and

4 that has been the ground rules for ATWS analyses since

5 1974 since ATWS is considered a very low probability

6 event.

7 MEMBER WALLIS: It doesn't matter. You've

8 got a criteria and it has got to be satisfied.

9 MR. MIRANDA: Yes. Yes.

10 MEMBER WALLIS: Probably or not.

11 MR. MIRANDA: And it is satisfied, 3193.

12 MEMBER WALLIS: And I know that large

13 break LOCAs are very unlikely, but you still had to

14 satisfy criteria.

15 MR. MIRANDA: That's right.

16 MEMBER WALLIS: So I don't accept the

17 argument that it's unlikely and therefore you don't

18 have to worry about it.

19 MR. MIRANDA: No. That's not my personal

20 judgment. This is what the Staff has decided during

21 the ATWS evaluations which have been going on since

22 1969 and then ended in the 1986 rule.

23 MEMBER WALLIS: That's a part of

24 exasperation reading the SER was that I just read this

25 whole thing and it says the applicant assumed this,

1 this and this and the ends of the paragraph saying --
2 or the several pages saying that he met the
3 regulations. But unless I get into the details of how
4 you let him calculate these numbers and how you
5 evaluated whether or not they're satisfactory, I have
6 no way of telling whether I give credibility to what
7 you have done. And therefore, I need that
8 presentation. I'm not sure I'm going to get it. So I
9 may just have to defer and say I don't know whether or
10 not this is a reasonable uprate, even though I may be
11 impressed with what the licensee has done. Because I
12 cannot follow the train of thought whereby the staff
13 approves the numbers that are submitted to it.
14 MR. MIRANDA: I will be talking about that
15 in my presentation later.
16 MEMBER WALLIS: Then we're going to have
17 this conversation again.
18 MR. MIRANDA: Yes.
19 MEMBER WALLIS: Thank you.
20 I'm sorry to take so much time from the
21 applicant.
22 MR. FINLEY: Well, that's fine. Important
23 questions.
24 The next significant event is the locked
25 rotor event, condition IV event. The pressure

1 criteria is based on a 120 percent of design in this
2 case, and you can see the margin that we have there.
3 For overheating, the loss of load event at
4 most limiting condition II with respect to
5 overpressure. And again this just takes into the
6 sizing of the pressurizer which was asked earlier on
7 this morning. The result is close to the acceptance
8 criteria, which is 110 percent of design pressure.
9 This was the event that was used to establish the
10 limiting pressurizer safety valve setting that we
11 talked about with respect to the license amendments
12 previously.
13 For the feed line break analysis, that of
14 course is a condition IV event. And here the
15 acceptance criteria relates to not having saturation
16 condition in the hot leg and we demonstrated that what
17 remains subcooled with 2 degrees margin.
18 ATWS we just mentioned briefly the
19 acceptance criteria of 3200 psig, 3193 the result.
20 For overcooling for steam line break it's
21 a condition IV event. This event actually had not
22 previously been analyzed for Ginna. We've added that
23 to our licensing basis with EPU. And we continue
24 demonstrate conservatively that we don't have clad
25 damage for this event.

1 MEMBER WALLIS: Well, again, this linear
2 heated or something --
3 MR. FINLEY: Heat rate, yes.
4 MEMBER WALLIS: Where does 22.7 come from?
5 MR. FINLEY: Let me ask.
6 MEMBER WALLIS: Is this in a reg. guide or
7 something or where does it come from?
8 MR. FINLEY: Yes. That's one of the SAFDLs
9 for the Westinghouse fuel, Specified Acceptable Fuel
10 Design Limits for the fuel. Let me ask Westinghouse.
11 MEMBER WALLIS: So this is something
12 that's written into the law in some way, 22.7? It's
13 been approved and all that? This is actually a
14 regulatory position of the Agency, 22.7? Yes?
15 MR. FINLEY: Let me ask Westinghouse.
16 Chris or Roberta.
17 Okay. We're going to have to take that
18 question and get back to you with respect to the basis
19 for the 22.7.
20 MEMBER WALLIS: Also the basis for 22.67.
21 They're so close and I'm just interested in where they
22 come from.
23 CHAIRMAN DENNING: The other element
24 that's so strange about this is how many -- and some
25 of these things are clearly very closely coupled and

1 it's not too surprising that some of these DNBR happen
2 to be so close. But things like the pressurizer -- I'm
3 sorry, the maximum pressure which is somewhat
4 independent from the DNBR, here's within .4 of a
5 criterion and then this somewhat independent thing,
6 the DNBR is also so incredibly close to the criterion.
7 And one would expect -- how have you tuned this
8 somehow so that they're all right --
9 MR. FINLEY: I understand the point. And
10 that's not by coincidence. It's really an outcome of
11 the process. In other words, we would revise the
12 inputs into these methods until we got the acceptable
13 results. And again --
14 CHAIRMAN DENNING: And so you keep your
15 setpoints --
16 MR. FINLEY: -- we're relying on
17 conservative --
18 CHAIRMAN DENNING: -- you mean things like
19 that?
20 MR. FINLEY: Pressurizer safety valve
21 setpoints, for example, is key to limiting the
22 overpressure for the loss of load.
23 MEMBER WALLIS: So you're changing the
24 physical variables? You're not changing some
25 correlation or some assumption --

1 MR. FINLEY: Well, in that case that's a
2 physical variable. In other cases it may be
3 analytical type margin.
4 MEMBER WALLIS: So the old joke about this
5 used to be that you simply have a loop in the program
6 that says if you don't get the answer you want, go
7 back and assume something else. Now that's not the
8 way you get the numbers so close, it can't be.
9 MR. FINLEY: No. No.
10 MEMBER WALLIS: But there must be some way
11 that you worked to get the numbers so close.
12 MR. FINLEY: And that's correct. Certainly
13 as part of the process we run these events the first
14 time, we collaborate with Westinghouse with respect to
15 the sensitivity of the event based on the inputs. And
16 we decide to make changes in the inputs and changes to
17 our operating margin at the site. And that's what
18 we've done in this cases. So although some of these
19 results are independent, they come from different
20 events and driven by different parameters. The reason
21 two or three are close is because we went through that
22 process to revise our operating strategy, our
23 setpoints and so forth to make these results
24 acceptable.
25 CHAIRMAN DENNING: If we went back and

1 looked at Kewaunee, we would see basically the same
2 type of thing? Would they all be up against their
3 limits?
4 MR. FINLEY: I can't speak to all of the
5 Kewaunee results here. I can't speak to that. I don't
6 know the details.
7 MEMBER WALLIS: I've never seen this
8 before. I mean, usually in these uprates we still have
9 a large margin in that the numbers are not close up to
10 some limit.
11 CHAIRMAN DENNING: Well, we have to be
12 careful. I mean, these are not safety limits and they
13 have margins built into them.
14 MEMBER WALLIS: Right.
15 CHAIRMAN DENNING: But we're not taking up
16 all of that.
17 MEMBER WALLIS: We're taking it all off.
18 CHAIRMAN DENNING: We're going right up to
19 the --
20 MEMBER WALLIS: Right, which I haven't
21 seen anything like this before. It's really striking.
22 MEMBER SIEBER: These aren't the only
23 limits. There are other limits where they don't
24 approach them so closely.
25 MEMBER WALLIS: Are you just showing the

1 worse --

2 MR. FINLEY: Right. I'm obviously picking

3 the most limiting events. And these are the ones

4 that, you know, with respect to margins to the

5 acceptance criteria are the tightest.

6 MEMBER WALLIS: So you're not going to

7 give--

8 MR. FINLEY: But again -- for example, for

9 the loss of load analysis we don't take credit for a

10 spray system that would be there and it would be

11 operating, it's not safety related. We don't take

12 credit for the PORVs, the relief valves that would

13 accurate before the safety valves.

14 I mean our typical loss of load event at

15 Ginna results in much, much lower pressures than what

16 you see here. So these are conservative methods,

17 again, conservative --

18 MEMBER WALLIS: But if you read the SER

19 there's many, many more events than this?

20 CHAIRMAN DENNING: Right.

21 MEMBER SIEBER: Yes.

22 MEMBER WALLIS: And they always end up

23 saying the regulations are met.

24 MEMBER SIEBER: Right.

25 MEMBER WALLIS: What I want to see is a

1 table like this for all events which may be, you know,
2 35 or something. And then showing that these are the
3 events which we have to think about because they're so
4 close to some limit and arguing in some detail about
5 why one part in ten thousandths is an acceptable
6 margin for these things.
7 MR. FINLEY: Right.
8 MEMBER WALLIS: That's what I was looking
9 for. I never found anything like that in the SER.
10 MR. FINLEY: In the licensing report we
11 have a table that we could show you. We can make that
12 available to you later today, I'm sure, that lists all
13 the events.
14 MEMBER WALLIS: Well, I'm very surprised
15 because in general I think that you guys seem to have
16 done a good job. And I just don't understand why I've
17 suddenly discovered that these numbers are so close in
18 this table.
19 MR. VERDIN: This is Gord --
20 MEMBER WALLIS: I had not seen them
21 before.
22 MR. VERDIN: This is Gord Verdin. I do
23 have some comments on this.
24 First of all, the 22.7 kilowatts per foot
25 is a 14 by 14 422V+ kilowatts per center line melting.

1 MEMBER SIEBER: Right.

2 MR. VERDIN: So it is a limit for that

3 particular fuel design.

4 The other thing is one of the reasons some

5 of these limits look as close, as I mentioned in my

6 previous discussion, that we've made a transition from

7 CAOC to RAOC. And when you make that transition to

8 RAOC, you try to get the bands that you were allowed

9 to operate within wide enough to give you operating

10 margin. So some of your initiating conditions for

11 these events are closer than they would have been in

12 the past when we had CAOC analysis.

13 MEMBER MAYNARD: Well, as I recall, most

14 of these criteria have most of the margin built into

15 them.

16 MEMBER SIEBER: Right.

17 MEMBER MAYNARD: So as long as you meet

18 that criteria, you have the margin and that you

19 typically will come close to these in a number of

20 areas to provide yourself operating margin. You don't

21 actually set setpoints and things to the exact --

22 MEMBER SIEBER: Limit.

23 MEMBER MAYNARD: -- limit that you could.

24 MR. FINLEY: That's correct. That's

25 correct. These acceptance criteria set the limit

1 beyond which we begin to infringe on the safety
2 margin. Below these limits we consider that operating
3 margin. And that's how we approached the analyses.
4 MR. DUNNE: This is Jim Dunne.
5 I think another thing that we need to
6 remember is typically for a lot of the parameters
7 instead of inputs into these analyses, they're skewed
8 in a conservative reaction. For example pressurized
9 water level; if for a particular analysis it's
10 conservative to maximize pressurizer water level, you
11 take your nominal and you throw your uncertainty and
12 raise it to a higher value as a starting point. Or if
13 it was conservative to minimize it, you would take
14 your nominal and reduce it by your uncertainty to a
15 starting point.
16 So you've got a lot of the inputs into
17 these analyses that have been skewed in a conservative
18 direction to give you conservative result as a final
19 output.
20 MEMBER WALLIS: Well, this reactivity to
21 this rod withdrawn thing. That must depend on the
22 time and the cycle at which it happens?
23 MR. FINLEY: That's correct.
24 MEMBER WALLIS: Is this the worst case
25 you're showing us here?

1 MR. FINLEY: We look at different times in
2 cycle, we look at different rod positions. And you
3 have to have rods inserted.
4 MEMBER WALLIS: Well, that depends on your
5 whole fuel arrangement and everything.
6 MR. FINLEY: That's correct. That's
7 correct. We look at all those. This is the most
8 limiting result of all the times --
9 MEMBER WALLIS: So you've run a lot of
10 calculations with a lot of different inputs?
11 MR. FINLEY: That's correct.
12 MEMBER SIEBER: That's part of the reload
13 safety evaluation.
14 MR. DUNNE: Right.
15 MR. FINLEY: That's correct.
16 MEMBER SIEBER: You do it every cycle.
17 MR. DUNNE: And when you your fuel reload
18 for any particular cycle, you got to look at your
19 reload design and see if it impinges upon any of these
20 --
21 MEMBER WALLIS: Right. So there might be
22 some reloads that gave you 27.486 --
23 MR. DUNNE: And if we did that we--
24 MEMBER WALLIS: --2748.6.
25 MEMBER SIEBER: Then you need to change

1 something.

2 MEMBER WALLIS: Then you go and change the

3 reload.

4 MR. DUNNE: Well if we do a reload report

5 and we get a number that's outside the band that

6 presently analyzed, we basically have to review it

7 whether we can accept that change under 50.59 or

8 whether it's not accepted in the 50.59, then we got to

9 go back and get the Commission's approval before we do

10 that. Ideally what we would do would be to change the

11 core design to stay within the design limits that

12 we've been licensed to and not try and raise the

13 limits higher.

14 MEMBER SIEBER: And I think that's

15 typically what happens. In a situation like Ginna it

16 is not surprising to me that you would find some of

17 these things close to or up against a limit because

18 the designer's question is how much can I increase the

19 power without exceeding a limit. And they worked very

20 hard to do that, and they may come right up next to

21 a limit and say that's how many megawatts I can get

22 out of the machine without exceeding a limit. And if

23 he would do less then that, then he wouldn't be

24 fulfilling the design requirement which is how much

25 can I get out of the machine and still not exceed the

1 limit.

2 So I'm not surprised that they're close on

3 some of these.

4 MR. FINLEY: That's correct. And that

5 actually responds to the question I think Dr. Wallis

6 had earlier, or one of the gentleman had earlier,

7 which events set the power limits. These are the

8 events here that set the power limits we've chosen.

9 MEMBER WALLIS: Well, I guess we could

10 spend a lot of time on everything. I don't want to do

11 it. But just look at the rod injection, less than 200

12 curies per gram, and we have looked at -- it's a

13 knowledge base for fuel damage. And there's quite a

14 bit of uncertainty in that that's 200 curies per gram.

15 And over the years there have been efforts to change

16 the number in response to what we know.

17 So that's certainly one where I wouldn't

18 expect you to try to get within .01 percent or

19 something.

20 MR. FINLEY: I understand that.

21 MEMBER WALLIS: I mean, we could spend

22 forever on all these numbers. I don't want to do it.

23 It's just that this is a rather striking presentation,

24 this particular slide here.

25 MR. FINLEY: And let me also say --

1 MEMBER WALLIS: Maybe we should move on.

2 MR. FINLEY: Okay.

3 MEMBER SIEBER: I just would, not trying

4 to belabor the point, point out that depending on

5 where the issue came up in the licensing process

6 determines to some extent how it's treated.

7 For example, the ATWS event as the staff

8 has reported has been out there and the subject of

9 policy and rulemaking for a long time. And because it

10 is not a likely event, for example, ATWS mitigation

11 equipment is not safety related. It's not safety

12 related equipment reflecting the fact that you aren't

13 going to get an ATWS with a combination of other kinds

14 of accidents like outages and so forth.

15 So there are a lot of twists and turns in

16 the rules that determine what these limits really are

17 and what they mean. There's a long history behind a

18 lot of this.

19 MEMBER WALLIS: I'd like to request that

20 when you make a presentation to the full Committee you

21 don't fail to show this sort of slide. Because

22 sometimes what happens is that the points that are

23 sensitive in the Subcommittee meeting get passed over

24 when it comes to the full Committee. And I think you

25 want to be completely open about this.

1 MR. FINLEY: All right. We'll include this
2 slide in that presentation.
3 CHAIRMAN DENNING: You can proceed now.
4 MR. FINLEY: Again, sticking with results
5 from the safety analysis with respect to the LOCA
6 analyses, large break Pclad temperature 1970 as
7 compared -- I didn't show the acceptance criteria
8 here. You know 2200.
9 Small break is actually not -- the review
10 from the Staff is not complete. But the current result
11 submitted is 1167. Obviously, a margin there.
12 MEMBER SIEBER: If you were to use your
13 old methodology, what would that number have been?
14 MR. FINLEY: Let ask Jeff Kobelak from
15 Westinghouse.
16 MEMBER SIEBER: 2195 maybe?
17 MR. FINLEY: Let me ask Jeff Kobelak to
18 answer that question.
19 MR. KOBELAK: With the SECY methodology at
20 the prior to EPU conditions, the 95/95 PCT was 2087
21 degrees.
22 MEMBER SIEBER: Which was okay.
23 MEMBER WALLIS: So you can certainly buy
24 something by changing the methodology?
25 MR. FINLEY: That's correct.

1 With respect to the containment, you see
2 the results here for the LOCA and the steam line
3 break, 54.2 psig as compared to the design pressure
4 for 60 for LOCA --
5 MEMBER WALLIS: I'm sorry. When he said
6 "the number is" he was talking about the large break?
7 MR. KOBELAK: Yes.
8 MEMBER WALLIS: Yes. Thank you. Just
9 clarifying.
10 MR. FINLEY: And that result 54 pounds is
11 comparable to what we had for LOCA now, slightly
12 higher.
13 For steam line break 59.6 psig, it's
14 actually a little lower than our current licensing
15 basis for a steam line break. That's a tight analysis
16 for Ginna even now. When we installed the fast acting
17 feed insolation valve, it actually took that single
18 failure away as the limiting case for steam line break
19 containment. But there are other single failures that
20 also result in this 59.6.
21 MEMBER WALLIS: You know, when I read the
22 SER I read a statement that said the licensee stated
23 that no fuel damage is postulated to occur because of
24 a main steam line break. Well, it maybe true that
25 there's no fuel damage. But you can't assume the

1 answer. You can't just postulate something. You've got
2 to have some justification for it.
3 MR. FINLEY: Well, that's correct. And we
4 I think mentioned earlier that when we did the steam
5 line break under non-LOCA we demonstrated no clad
6 damage.
7 MEMBER WALLIS: Well, you demonstrated.
8 But the SER it simply says you postulated. That's not
9 a proper description of what you did.
10 MR. DUNNE: That's correct. It's not an
11 assumption. It's based upon analyses.
12 MEMBER WALLIS: Right. And in the rod
13 injection accident you assumed that a certain amount
14 of rods fail? Did that just come from the sky or did
15 you know how many failed and for some reason?
16 MR. FINLEY: Are you moving ahead to dose
17 assessment slide?
18 MEMBER WALLIS: Well, I'm just looking at
19 how -- trying to figure out what you did in terms of
20 calculating things and how the Staff evaluated them.
21 And when I see that they simply say you assumed the
22 answer, I don't understand how that's an acceptable
23 position to have.
24 CHAIRMAN DENNING: In some respects it's
25 a question for you. It's really SER verbiage, but

1 really the question in both of these cases was did you
2 really make assumptions or did you actually perform
3 analysis --
4 MR. FINLEY: We actually performed
5 analysis to demonstrate the fuel behavior during these
6 transients, yes.
7 CHAIRMAN DENNING: Okay. I think you can
8 continue.
9 MR. FINLEY: I do want to mention that
10 although the design pressure of the containment is 60
11 psig, when we replaced the steam generators in 1996 we
12 did a structural integrity test of the containment at
13 82 psig, just as an example to show the conservative
14 nature of the design pressure.
15 With respect to dose assessments, I
16 mentioned earlier that we already had approved last
17 year the --
18 MEMBER MAYNARD: I'm sorry. That was done
19 after the replacement of the steam generators?
20 MR. FINLEY: That's correct.
21 MR. DUNNE: Yes.
22 MEMBER MAYNARD: Because you had to put a
23 hole in the containment to put those in. So you did
24 the integrity test after that.
25 MR. DUNNE: This is Jim Dunne.

1 Yes, we did a normal integrated leak rate
2 test, we went up to 115 percent design and checked
3 containment leakage, which was nominally 69 psig. And
4 then after we completed that test, we took it up to 72
5 psig, held for a while to monitor conditions to
6 basically check containment integrity at that higher
7 pressure.
8 MR. FINLEY: The alternate source term
9 methodology was approved last year for Ginna, and
10 that's what we utilized. For EPU upgrading, of course,
11 the new source term.
12 Also of importance is that Ginna recently
13 modified the plant to incorporate two new safety
14 related ventilation trains for the control room. We
15 also did the in leakage test with tracer gas and came
16 up with a recent far below what was assumed in the
17 control room dose assessment, 300 scfm. The source
18 terms are consistent with Reg. Guide 1.193. We did
19 update the X/Qs. And the calculated doses, as you'll
20 see here in a second, are within the guidelines of 10
21 CRF 50.67.
22 MEMBER SIEBER: Do you have any idea of
23 what the result would have been not using alternate
24 source term, but using TID 14844?
25 MR. FINLEY: Let me ask Ken Rubin here.

1 No, we don't have that information. We didn't do
2 those analyses. It would be difficult to estimate it.
3 MEMBER SIEBER: Well, I don't want you to
4 guess at them.
5 MR. FINLEY: Right.
6 In terms of the results, as you can see we
7 essentially redid the dose assessment analysis for all
8 of the events. Here they are before you. I won't go
9 down each one.
10 Of particular note are the locked rotor
11 and the large break LOCA results for the control room
12 in particular. Those were the only two results which
13 actually increased more than ten percent of the margin
14 to the acceptance criteria. That's important, as you
15 know, with respect to 50.59. Those results need to be
16 reviewed and approved by the Staff. And they're in the
17 process of doing that.
18 All the other results, small changes with
19 respect to the margin to the acceptance limits.
20 MEMBER MAYNARD: And even those were
21 within the criteria, but there was more than a 10
22 percent change, so --
23 MR. FINLEY: That's correct. Still within
24 the criteria.
25 And in conclusion with respect to the

1 safety analysis, all of the safety analysis met the
2 acceptance criteria. This demonstrates that the NSSS
3 and Emergency Safety Features at Ginna are robust.
4 And, again, this is not a surprise. This was the
5 expectation given our similarity to the Kewaunee
6 design and their safe operation to date.
7 I think at this point we'd like to ask the
8 staff to make their presentation.
9 MR. MILANO: Before we get started, I'd
10 like to clarify one point. You asked about the
11 approval of ASTRUM. And while it's been approved
12 generically, that is one of the amendments that's
13 still under -- that is the amendment that's still
14 under Staff review that constrains the power uprate.
15 We have not yet issued an amendment approving the use
16 of that best model on Ginna. Okay.
17 Also for the Staff's review, as with
18 Ginna, we're going to have two different organizations
19 providing the Staff's response. We'll have the PWR
20 Systems Branch going over the various accidents and
21 transients. And then followed up by the Accident Dose
22 Branch, which will provide our accident dose
23 consequences.
24 Sam Miranda, although there were a number
25 of individuals that reviewed the reactor systems area,

1 Sam Miranda has the lead for the overall management of
2 the reactor systems review.
3 And also speaking today along with Sam
4 will be Kent Wood and Lyn Ward.
5 MR. MIRANDA: Yes. And we also have here
6 John Nakoski, the branch chief for Pressurized Water
7 Reactor Systems Branch.
8 At this point I just want to introduce the
9 topics we're going to cover and go right to Kent Wood
10 who will discuss the fuel assemblies nuclear design
11 and thermal hydraulic design. Then I'll come back and
12 we'll talk about the accident analyses. And I'll give
13 it to Kent Wood right now.
14 MR. WOOD: Good morning, gentlemen. My
15 name is Kent Wood. I'm a reactor systems engineer in
16 the Pressurized Water Rector Branch.
17 MEMBER WALLIS: Excuse me. I'm just trying
18 to look at the schedule here. We have all kinds of
19 material being presented, but isn't safety analysis
20 the key thing in all of this? I'm just wondering why
21 we have a short time on safety analysis and a lot of
22 time on things which may not be so important to
23 safety.
24 MR. WOOD: That's not my purview.
25 MEMBER WALLIS: I'm just wondering it

1 would be appropriate to dig into the safety part much
2 more than some of these other parts and maybe take a
3 bit more time with it. I'm not sure, but that's the
4 comment I have.
5 MR. MILANO: You know, if you want to
6 spend some more time, the Staff can accommodate your
7 schedule and stuff. This was our best understanding
8 at the time as to how much time based on the length of
9 our presentations and giving you what we thought at
10 the time sufficient time to ask questions.
11 CHAIRMAN DENNING: We'll give some thought
12 to this perhaps over lunch as to whether -- and it may
13 be very difficult for you to readjust anyway. But my
14 guess is that when we get to some of these areas,
15 we'll move through them very quickly. We'll see.
16 MR. MILANO: Right.
17 MR. WOOD: In executing their extended
18 power uprate, Ginna is switching from what is
19 currently Westinghouse's design of the optimized fuel
20 assembly to a 14X14 422 Victor Plus or V+ design,
21 which is actually a derivative of the fuel design that
22 was approved as the Vantage Plus design under WCAP. It
23 was approved the NRC and then subsequently modified
24 slightly by Westinghouse. This is the same fuel
25 assemblies that are essentially the same assemblies

1 like were discussed earlier by Mr. Verdin. That these
2 are currently installed and in use at Point Beach and
3 Kewaunee. Kewaunee is actually these assemblies at
4 the current power level essentially that Ginna is
5 requested.
6 The notable difference is that over the
7 OFA fuel that Ginna currently have is that you're
8 going to put the more fuel in. It's approximately
9 about 20 percent more fuel that allows them to keep
10 their fuel densities and their power densities down.
11 The fuel rods are longer, that were
12 discussed. That accommodates your increased internal
13 pressure from the burnups.
14 And also what was addressed by the
15 licensee was the RCA position of the deltas and that
16 due to the top nozzle change.
17 What I focused on in my review was I
18 wanted to look at the transition effects considering
19 the differences between the OFA fuel and the 422V+
20 fuel. And I focused on like the flow differentials
21 that they were going to have that would incur
22 vibrational differences and flow starting for the OFA
23 fuel. And I also looked at the assembly
24 compatibilities. And I also went through the SRP,
25 standard review plan, acceptance criteria which was

1 for fuel damage. I looked at stress and strain,
2 fatigue, corrosion, crud, internal rod pressure and
3 growth. And for the rod rod failure on focused on like
4 threading an hydrogen pickup, overheating of the fuel
5 in the clad and for fuel culpability it was the
6 structural integrity.
7 A lot of that I looked at. We conducted an
8 audit at the Westinghouse facilities in Monroeville
9 the first week in November. During that I looked at
10 the calculations and reports for their flow testing
11 mechanical capability. I looked at their calculations
12 and reports for their control rod drop times. And
13 their calculations for their fuel rod performance.
14 These were all done in accordance with previously
15 approved NRC codes and methodologies.
16 With respect to nuclear design, they're
17 changing some design parameters and was discussed
18 before. Design parameters are subject to the actual
19 plant specific or core specific parameters are subject
20 to change from one cycle to the next. What they have
21 done is they're changing boundary parameters that they
22 use in their safety analysis.
23 And as was mentioned before, I forgot who
24 asked the questions, there's a standing of
25 Westinghouse reload design methodology which a WCAP,

1 I think it's 9272 which would tell them that they go
2 through a list of key parameters. And if these key
3 parameters are met for a given plant, each plant would
4 have it's own key parameters. Then you verify that
5 the design is bounded and therefore you wouldn't have
6 to redo each analysis every time you reload the core.
7 As I mentioned down here, it's the 9272
8 WCAP that provides the continuity.
9 The actual acceptability for a given
10 nuclear design parameter is actually demonstrated by
11 the acceptance of the transient analysis. And to do
12 that I went through and reviewed the transient
13 analysis and the results that were reached because the
14 transients were reviewed by a different staff member.
15 And their results and conclusions to show that the
16 transient analysis were acceptable at these design
17 parameters as the bounding limits.
18 With respect --
19 MEMBER WALLIS: How did you determine that
20 they're acceptable?
21 MR. WOOD: Excuse me, sir.
22 MEMBER WALLIS: How do you determine that
23 they are acceptable?
24 MR. WOOD: Okay. Well, the design
25 parameters, nuclear design factors are factors in how

1 the core responds during a transient, the maximum
2 limits that they --
3 MEMBER WALLIS: But you determine that the
4 methods used were approved or you look at the results
5 and you apply some criteria or something?
6 MR. WOOD: Well, these are parameters that
7 factor into the transient analysis. And if the
8 transient analysis using these design limits show
9 acceptable results, then these nuclear design
10 parameters would be acceptable.
11 MEMBER WALLIS: So the bottom line is you
12 compare some number with some other number, is that
13 what you do?
14 MR. WOOD: As a review at the NRC, I don't
15 have a different number to compare to. What the
16 analysis that's performed is that the transient
17 analysis will take a given set of input parameters of
18 which these would factor in the different transients.
19 MEMBER WALLIS: Right.
20 MR. WOOD: And then if that transient
21 shows acceptable results with those input parameters,
22 then they're considered acceptable. If it doesn't,
23 then you decide as a designer for designing that core
24 or those parameters what you need to modify in your
25 design or your plant to make them acceptable.

1 MEMBER WALLIS: Because I mean I could see
2 that if you read this thing, you could say well you go
3 through and these look like reasonable design
4 parameters. But I'm not quite sure about how they
5 chose their hot channel factor. And then you go
6 through and then you compare with some criteria. And
7 if the criterion satisfied with a lot of margin, you
8 may not go back and review what you questions before.
9 But if you're very close to some limit, you would say
10 well I wasn't too convinced about they did with hot
11 channel factor. I'd better go back and dig into that
12 and find out if that is sort of swinging the results
13 too close to the limit.
14 And I just wanted to be sure you guys are
15 digging into things which might give you a little bit
16 of concern if they influence the answer too much and
17 they're not too well presented, and things like that.
18 It's just not a routine checklist and you
19 just go through it without much thought?
20 MR. WOOD: No, sir. But that iterative
21 process of checking with the individual parameters
22 would be done when that transient analysis was
23 reviewed.
24 MEMBER WALLIS: What helps you achieve
25 credibility sometimes is by saying everything looked

1 fine except I was a bit concerned about this and this
2 is what I did. And if you can explain how you did it,
3 that sometimes help achieve credibility. Just reading
4 through blind statements everything works fine doesn't
5 tell us anything about how you went about it.
6 So I don't want to interrupt your --
7 MR. WOOD: No, that's okay.
8 MEMBER WALLIS: -- train of thought here,
9 but that would help..
10 CHAIRMAN DENNING: Let's interrupt you
11 just a little bit on more on that. In the parameters
12 that you've identified up there, those are all inputs
13 to the transient analysis, yes? Those are all inputs?
14 MR. WOOD: They're not all of the inputs,
15 but they are inputs --
16 CHAIRMAN DENNING: Yes, but they're all
17 inputs?
18 MR. WOOD: -- of the safety analysis. You
19 know your shutdown margin, as was described earlier,
20 they have now fully put in the feedwater regulation
21 modification. They needed a shutdown margin of I think
22 it was 2400 PCM. And with that they show that they
23 only need a shutdown margin of 1300 PCM. So that's an
24 example of where you make a plant change to, you know,
25 like shutdown margin they're losing shutdown margin

1 because of the uprate because of the additional fuel
2 and reactivity that's going to be in the core. So in
3 order to gain some of that margin and make sure that
4 their examples are going to be acceptable with that
5 uprate and that decreased shutdown margin due to the
6 uprate, they go in and they make a modification of the
7 power plant that, you know, like this is demonstrating
8 iterative effect. I'm going to lose some shutdown
9 margin, I need to gain some, what can I do to do that.
10 And one of the things they did to do that was to make
11 the feedwater reg mode change. And now the shutdown
12 margin that they need to have to show acceptable
13 results, you know limiting transients would be a steam
14 line break at the end of cycle is now 13000 PCM as
15 opposed to 2400 PCM because of a modification they
16 made to the plant.
17 And so those are the types of things that
18 we question. Several of those things get questioned
19 back and forth over like questions that the Staff
20 asked to the licensee to explain further and more
21 detail.
22 I mentioned that we conducted an audit
23 with Westinghouse where we actually reviewed some of
24 their calculations. And one of the things that I was
25 concerned about was the incompatibility differences

1 between the old OFA fuel and the new 422V+ fuel. Like
2 I reviewed those calculations for the flow
3 differentials, the testing reports that they did for
4 establishing the fuel assembly loss coefficients, and
5 those type of things. Looked over their rod drop
6 calculations for their rod insertion times. I
7 questioned them about the raw positions on how they
8 were going to adjust RPM, on how they were going to
9 deal with that with the different heights and things
10 like that.
11 And so it's not just that -- what you see
12 in the SER, Safety Evaluation Report, isn't everything
13 that we've ever discussed with them. It's a, you
14 know, perhaps too much of a *Reader's Digest* version of
15 what we've asked and discussed with the licensee over
16 the course of the review.
17 CHAIRMAN DENNING: I was trying to get a
18 feeling for within the context of where you are right
19 now, when you talked about acceptability shown by
20 transient analyses are you talking about operational
21 transients are you talking about actual analysis?
22 MR. WOOD: I'm talking about the safety
23 analysis transients that they --
24 CHAIRMAN DENNING: Safety Analysis
25 transients. So the DNBR that in comparison with some

1 criterion would be what you would determine to be the
2 acceptability.
3 MR. WOOD: Right.
4 CHAIRMAN DENNING: So things like that?
5 MR. WOOD: Yes, sir.
6 CHAIRMAN DENNING: Okay. I understand.
7 Okay. And the DNBR, I anticipate another
8 lively discussion.
9 In the change from the OFA to the 422V+
10 fuel there is several differences. One is that due to
11 primarily a change in the grid decision and some other
12 aspects, and the top nozzle I believe, this would be
13 the actual total assembly coefficient for the flow --
14 flow loss coefficient for the new fuel is less. And
15 that's what drives what we were talking about earlier
16 as the pressure differential across the fuel. So that
17 can get their cross flow and the mixing and things
18 like that.
19 I probably should have put more of that
20 translates into your transition core DNBR penalty.
21 Now they developed their DNB penalty in accordance
22 with the previously established and approved NRC
23 method that was done. So they did that in accordance
24 with -- because it's not the first time that
25 somebody's transitioned core designs that they've had

1 to account for these type of flow imbalances between
2 the assemblies and the core. So there's a methodology
3 that's been established to deal with that.
4 They changed from the THINC IV code to the
5 VIPRE I code. The VIPRE 1 is the more flexibility, it
6 always them to a little more things in the transient
7 analysis. It handles the transient analysis during the
8 nonsteady state activities better than the THINC does.
9 So the similarities is the use of the
10 revised thermal design procedure with the DNB
11 correlations that WRB1 and in the standard thermal
12 design procedure with the W3 correlation.
13 And then the limits are pretty much the
14 same from before and after. Those limits were -- I'll
15 discuss them because I know that they're of interest
16 to the Committee.
17 The limits for -- and then there's a DNBR
18 limit is applied -- a penalty is applied to the OFA
19 fuel so that the limit for the OFA fuel is less than
20 that for the 422V+ due to the flow disparities between
21 the two.
22 The flow correlations, these correlations
23 have a limit. And for the correlation for both of them
24 for the WRB1, the correlation limit is 1.17 DNBR. And
25 what that means is that that -- to the limit that' set

1 when that code and correlation and methodology for
2 applying that code is applied to and approved by the
3 NRC, that takes into account the exact codes and
4 correlations and methodologies of how it's applied.
5 Able to accurately within the 95/95 percent confidence
6 predict or regurgitate the data that it's based on.
7 And then that's the correlation limit.
8 And for both the OFA fuel and the 422V+
9 fuel that's 1.17.
10 And then for a site specific limit you get
11 into a design limit which they take and they put the
12 site specific uncertainties into that. And for Ginna
13 for the OFA and for the 422V+ fuel after they put in
14 that, that's another design limit which is 1.24
15 percent DNBR.
16 And then to ensure that you have
17 additional margin to the analysis criteria, the
18 setpoint, the number that they're trying to prove that
19 they meet in the safety analysis limit as a DNBR limit
20 is 1.38.
21 So if you meet exactly 1.38, you're
22 already .14 percent over your design limit. So if you
23 meet exactly your safety analysis limit, you already
24 have margin over your design limit which includes
25 uncertainties. So that's how those uncertainties are

1 factored into trying to determine the acceptance for
2 your DNBR consideration.
3 CHAIRMAN DENNING: A question about the
4 additional cross flow between the two fuels in a
5 transition. Can you use VIPRE directly to determine
6 what the effect is on the DNBR or do you -- how do you
7 do that?
8 MR. WOOD: You can't calculate the
9 directly. What is done is you do a two core analysis,
10 one with assuming all of the one fuel design or the
11 other. And then you go through the transition penalty
12 process and determine -- okay, well I'm going to have
13 the first core, they're going to -- I believe the
14 number they're predicting is 53 assemblies of the
15 422V+. So your transition core penalty methodology
16 comes up with a relationship that is relative, is
17 based on the number of the different types of fuel
18 assemblies that you have in the core, it's a fraction
19 of those. And then based on that number you get a
20 penalty and then you apply that to the limited
21 assembly, like in this case it would be the OFA fuel
22 assemblies. So they'd get a penalty based on what
23 they're allowed to see as DNB for that assembly.
24 CHAIRMAN DENNING: I didn't understand.
25 MR. WOOD: I'm sorry.

1 CHAIRMAN DENNING: It sounds to me like
2 that there was -- that there were be flow diverted
3 from the one assembly to another assembly when they're
4 side-by-side that wouldn't be seen in uniform cores.
5 MR. WOOD: That's correct. That's what
6 causes the imbalance and the need for a transition
7 core penalty. Because those assemblies that have that
8 higher pressure resistance, they're going to see less
9 flow because it's going to go to the other less
10 resistent assemblies. And so you have to apply a DNB
11 penalty to those assemblies to make sure that they
12 still meet your acceptance criteria.
13 CHAIRMAN DENNING: Yes. But it sounded to
14 me -- I didn't under the way -- it sounded to me like
15 you're talking about a formula for calculating that
16 penalty that didn't seem phenomenological.
17 MR. WOOD: There's a methodology that
18 there is, that you do calculate a formula that's based
19 on the number of assemblies of the percentage of OFA
20 assemblies that you have in the core. And say okay now
21 I have to reduce that allowed DNBR for those type of
22 assemblies by a certain amount. And that's a penalty
23 that goes that on their DNBR limit.
24 CHAIRMAN DENNING: I wonder, can the
25 applicant jump in and help here as far as how you

1 actually determined that penalty?

2 MR. FINLEY: Mark Finley again. I'm not

3 a thermal hydraulic expert. Let me ask Westinghouse

4 whether they have someone here to answer that

5 question: How the flow diverges from the new fuel to

6 the OFA fuel is taken into account in the thermal

7 hydraulic analysis.

8 MR. DOMINICUS: My name is Dave Dominicus

9 from Westinghouse.

10 And no, we do not have a T&H expert with

11 us. We're going to call back to Pittsburgh.

12 MR. FINLEY: We'll get that answer for you

13 this afternoon, okay?

14 CHAIRMAN DENNING: Fine.

15 MR. DOMINICUS: Okay.

16 MR. WOOD: And with, I'd like to introduce

17 Sam Miranda to discuss transient analysis.

18 MR. MIRANDA: First of all, the SER that

19 you have is written according to the guidelines of the

20 review standard for extended power uprates. And a lot

21 of the language you see is template. The original

22 language is basically in the technical evaluation part

23 and the conclusions.

24 There were some differences I might point

25 that that relate to the Ginna plant design. For

1 example, it is an older plant and there is a
2 discussion in there about applicable GDCs. And in
3 large part they satisfied the applicable GDCs. One
4 GDC, for example, that did not apply is GDC 5 which
5 relates to dual plants on the same site. And
6 obviously, this plant is not covered by that.
7 There was a change in methodology that
8 Ginna shifted from LOFTRAN to RETRAN and from TINC to
9 VIPRE. And all of those codes have been approved by
10 the NRC.
11 The analyses were conducted 102 percent of
12 nominal power. The two percent is a typical number
13 added for uncertainty. And the intent was originally
14 to allow some space for measurement uncertainty
15 recapture power uprating, which I understand is not
16 going to happen.
17 There is also the consideration of steam
18 generators which were replaced in 1996. And some of
19 the analyses would be effected by the new steam
20 generators. The new steam generators are fairly
21 similar in design to the old steam generators in terms
22 of size and volumes.
23 There was also a license renewal granted
24 in 2004. And some of the analyses were considered
25 back then and there's no need to look at them again

1 this time around.

2 And concurrent with the EPU, we had the

3 fuel transition which has been discussed at length.

4 And this fuel transition does effect a number of the

5 accident analyses. It's not simply the power

6 uprating. There are changes in nuclear design

7 parameters such as shutdown margin as Kent mentioned

8 that would effect key analyses.

9 And then there's also the Tavg operating

10 window. And this sets a range of Tavg for normal

11 operation. And this required, for example, that

12 accident analyses be considered at various points

13 along this window to find a conservative initial

14 condition.

15 And then two plugging, a maximum of two

16 plugging of ten percent was assumed in the accident

17 analyses. Before the EPU it was 15 percent.

18 This slide just lists the events that had

19 been reanalyzed for the EPU for various reasons. And

20 I don't think I'm going to go into these in detail.

21 I'm sure you'll have questions. The time allotted to

22 me was very short and I just wanted you to have a

23 summary here and allow you to look through this and

24 come up with some questions.

25 The one thing I would say is that this

1 event, this EPU, since there is a fuel transition
2 involved and there are new steam generators required
3 the analysis of more transients than might be expected
4 in simply a straight EPU.
5 MEMBER WALLIS: Because there are very
6 many events here, and the discussion of them takes up
7 about a quarter of the SER, I think. And presumably
8 these are the kind of events that limit what they can
9 do in terms of power uprate.
10 MR. MIRANDA: Yes.
11 MEMBER WALLIS: And this is really where
12 they are pushing the envelope in various dimensions.
13 MR. MIRANDA: Well, then would you like--
14 MEMBER WALLIS: And yet we don't seem to
15 spend much time in this meeting discussing them.
16 MR. MIRANDA: I think there was a
17 misunderstand.
18 MEMBER WALLIS: Isn't this the guts of the
19 whole thing? Isn't this the basis for your decision;
20 you look at all these things and they're pushing their
21 limits in some ways, and then you decide whether
22 that's acceptable or not.
23 MR. MIRANDA: That's right. I was told
24 that to use maybe ten or 15 minutes. But if you want
25 to take longer --

1 MEMBER WALLIS: Well, it seems to me
2 that's the essence of the whole decision making, isn't
3 it? Lots of the other stuff is peripheral.
4 MR. MIRANDA: Well would you like to take
5 some more time and go through these?
6 MEMBER WALLIS: Well, what do we think?
7 CHAIRMAN DENNING: Well, i think what we
8 would like to do is for those ones that are limiting,
9 we'd like to look and see what your assessment is of
10 those relative to what the applicant's assessment was.
11 MR. MIRANDA: Okay. Mark Finley had a
12 good slide before indicating the limiting transients.
13 MR. MILANO: We've also got slides that
14 came out of section 2.8 of the licensing report. And
15 I'll provide those now.
16 MR. MIRANDA: Well, from my experience I
17 would say that the loss of flow, accident, is the
18 limiting transient in terms of DNB ratio. And that
19 was one of the events that was in an earlier slide by
20 Mark Finley.
21 In the license amendment request this is
22 referred to as the flow coastdown accident. And that
23 came very close to the DNBR limit of 1.38.
24 CHAIRMAN DENNING: You're looking at the
25 table that was just handed out to us, is that true?

1 MR. MIRANDA: Yes.

2 CHAIRMAN DENNING: And that's in section

3 15.3.1 --

4 MR. MIRANDA: Yes.

5 CHAIRMAN DENNING: The flow coastdown.

6 MEMBER WALLIS: I notice some other ones

7 we haven't seen before, like 15.2.2 loss-of-external-

8 electrical load, which isn't all that uncommon an

9 event. Your pressure is, again, remarkably close to

10 some limit.

11 CHAIRMAN DENNING: Well, let' come back to

12 that one. Let's focus for the moment on the one --

13 MEMBER WALLIS: Yes, I know. But I just

14 said they're discovering other ones which are very

15 close to the limit.

16 CHAIRMAN DENNING: Yes. Other ones, very

17 good.

18 MR. MIRANDA: Yes. Would you like to go

19 through these one-by-one --

20 MR. FINLEY: Actually let me correct.

21 That loss-of-load result was shown on a previous

22 slide. That was the one that was --

23 MEMBER WALLIS: Well, maybe I missed it.

24 MR. FINLEY: Yes.

25 CHAIRMAN DENNING: Thanks. Yes, let's

1 look at some of these key ones and just spend a few
2 minutes on some of these key ones. And let's start
3 out on the one that's 15.3.1, the one you pointed out
4 there.
5 MR. MIRANDA: Okay. Okay.
6 CHAIRMAN DENNING: Okay. And so talk to
7 us a little bit about that. And there are two numbers
8 here. And explain to us again the 422V+ versus what
9 the other number means.
10 MR. MIRANDA: Okay. For the loss of low
11 accident there are three cases that were analyzed by
12 the licensee. One is the partial loss of flow, which
13 is the tripping of one reactor coolant pump. Then
14 there's a flow coastdown accident, which is tripping
15 of both pumps. And then there's another accident
16 referred to as UF, under frequency. And this is the
17 event where the grid frequency decays and eventually
18 leads to a lose of reactor coolant flow, totally loss
19 of reactor coolant flow. And this is the one that is
20 the limiting event. It produces the lowest DNB ratio.
21 The analysis limit is 1.38. There are two
22 numbers listed there. They're both for the Vantage
23 Plus fuel. One refers to a typical cell, the other
24 refers to a thimble cell.
25 A thimble cell is the assembly that

1 contains the control rods.

2 The limiting case, as indicated, is the

3 1.35 and that's for the Vantage Plus fuel. The 1.392

4 is for the OFA fuel.

5 CHAIRMAN DENNING: Now when you look at

6 this and recognize the precision of the numbers and we

7 established 1.38 as a limit, if they had gotten 1.38

8 would that have been unacceptable?

9 MR. MIRANDA: No, that would have been

10 okay.

11 CHAIRMAN DENNING: That would be

12 acceptable?

13 MR. MIRANDA: Yes.

14 CHAIRMAN DENNING: So anything that's like

15 1.381, that's better -- you know --

16 MR. MIRANDA: Yes.

17 CHAIRMAN DENNING: Anyway, the question is

18 partly one of these extra significant figures that are

19 clearly of no true significance. Are they important

20 in this assessment?

21 MR. MIRANDA: They just show that they've

22 met the limit.

23 CHAIRMAN DENNING: Yes.

24 MR. MIRANDA: So 1.1381 means that they

25 met the limit. 1.38 would have been okay, too.

1 CHAIRMAN DENNING: 1.38 would have been
2 okay?
3 MR. MIRANDA: Yes. And the reason is that
4 there is a margin on both the number on the safety
5 analysis result.
6 CHAIRMAN DENNING: Yes.
7 MEMBER MAYNARD: I personally don't have
8 concern with coming that close to limit knowing that
9 the criteria has margins already built into that. And
10 that also the methodology that's reviewed and approved
11 is also shown to show conservatism and make the
12 approach.
13 If you wanted to change it where you went
14 to the actual limit and demonstrated how much margin
15 you had, then that would be a different process. But
16 you basically have margin built into the criteria and
17 an acceptable methodology that's been reviewed and
18 approved.
19 MR. MIRANDA: Yes, I agree with that.
20 CHAIRMAN DENNING: Yes. And I recognize
21 that the Staff has reviewed the basis for that. But I
22 think that we'd like to get close enough to that to
23 give ourselves some comfort that the uncertainties in
24 this 1.38 value that we come up, the methodology to
25 get to that, really do provide us the substantial

1 margin to a true safety limit that the Staff's already
2 gone through independently and convinced themselves
3 of.
4 And also, we recognize that although that
5 margin may be acceptable, it certainly is less than
6 what it is in the current design. And trying to get
7 a feeling for the risk significance is of going to the
8 marginal results is something of interest to us.
9 MR. MIRANDA: It's kind of hard to gauge
10 how much margin is lost by increasing the power level.
11 You expect some reduction in margin intuitively, just
12 because the power level goes up. But these are not
13 exactly linear scales that you can just compare like
14 apples and applies.
15 In this case the DNB correlation has not
16 changed, but there are other instances where
17 correlations do change from cycle to cycle. And you
18 have different safety analysis limits to compare to.
19 For this particular case the flow
20 coastdown accident involves an analysis by RETRAN to
21 calculate the flow coastdown accident in the reactor
22 coolant system and generates power level, reactor
23 coolant system temperature, flow and other conditions.
24 And these are then fed into a detailed core model,
25 VIPRE, which has the fuel assembly and the dimensions

1 and the pitch and all of that, including the thimble
2 and the typical, including the OFA and the Vantage
3 Plus fuel which actually calculated a DNB ratio for
4 the hot rod. And that is the number that you find.
5 That number is not from the bulk conditions calculated
6 by RETRAN.
7 CHAIRMAN DENNING: And the Staff has
8 reviewed these couple of codes and is there a safety
9 evaluation report on that? How do you bless it
10 through a safety evaluation report?
11 MR. MIRANDA: Yes. These methods have
12 been submitted to the Staff as topical reports and
13 they have been approved by the Staff in the past for
14 other plants.
15 CHAIRMAN DENNING: Yes.
16 MEMBER WALLIS: And the approval didn't
17 have conditions on it? It may be it's being used now
18 for conditions which were not used for its approval
19 before.
20 MR. MIRANDA: Yes, that's a good point.
21 And that is something that the Staff has to review
22 with every application that when an applicant uses an
23 approved methodology, that they're using it within the
24 limits of the approval. And that has been done.
25 CHAIRMAN DENNING: Okay. Did you want to

1 go back the to some of these other cases and look at
2 those?
3 MEMBER WALLIS: What do you do when you
4 see a number like, you know, 15.2.2 on the first page
5 which has 2748.8 versus 2748.5? Does that raise a
6 sort of flag with you that these are very close, I'd
7 better go back and be sure that everything is okay, or
8 do you just accept it?
9 MR. MIRANDA: Are you referring to --
10 MEMBER WALLIS: There's no criterion
11 there.
12 MR. MIRANDA: Okay. Okay.
13 MEMBER WALLIS: There's no criterion.
14 MR. MIRANDA: The pressures? You're
15 talking about the pressures then. Yes.
16 MEMBER WALLIS: I'm not sure. What are
17 showing here by analysis limit and limiting case, what
18 does that mean? An analysis limit means the criterion
19 that you apply?
20 MR. MIRANDA: Yes. Yes. The analysis
21 limit for peak pressure, for example, is 110 percent
22 of design pressure. And that goes for the primary and
23 secondary side.
24 MEMBER WALLIS: Presumably the 110 was not
25 109.9 or something. But that's what they've got, so

1 whatever. It's very close.

2 MR. MIRANDA: Yes.

3 MEMBER WALLIS: Does that raise a flag

4 with you and you go back and check into it in some

5 way?

6 MR. MIRANDA: It raises a very small flag

7 in the sense that, yes, I would see the number and

8 begin to question it and say why is it so close. But

9 then that leads to the review of the actual analysis

10 that produced that result. And I would need to make

11 sure that that analysis was conservative analysis,

12 that it was conducted using approved methods within

13 their limits and that the initial conditions that were

14 used were in the conservative direction. And if I'm

15 assured that those initial conditions were the

16 appropriate conservative values, then I know that

17 2746.8 is really lower than that. And this is --

18 CHAIRMAN DENNING: Have you done some

19 independent checking of these using those codes or did

20 you go to the vendor? I'm sorry, you went to

21 Westinghouse and you oversaw some calculations being

22 performed.

23 MR. MIRANDA: Okay. As a matter of fact

24 we went to Westinghouse November 1, 2 and 3. And Kent

25 Wood and I and Len Ward were all there, and John

1 Nakoski as well. And we reviewed the calculations
2 that were performed by Westinghouse for almost all of
3 these accidents.
4 We also reviewed the guidance that
5 Westinghouse uses internally for their analysts to be
6 sure that they produce consistent analyses.
7 And we also requested that Westinghouse
8 provide a copy of their LOFTRAN code at their local
9 office in Rockville for use by the Staff to perform
10 confirmatory analyses. And as a matter of fact, I did
11 an analysis for the loss-of-external load. And my
12 value came very close, within 2 psi of 2746.
13 MEMBER WALLIS: So the client or the
14 utility uses RETRAN?
15 MR. MIRANDA: Yes.
16 MEMBER WALLIS: That's not a Westinghouse
17 code. They would use a different code. I would be
18 prepared to expect that if you use a Westinghouse code
19 rather than RETRAN, you'd get a difference which was
20 bigger than the difference we're talking about here
21 between the limiting case and the analysis limit.
22 MR. MIRANDA: Well, RETRAN and --
23 MEMBER WALLIS: So using another code
24 would give a different answer which might be over the
25 limit, quite likely. Just as likely as not.

1 MR. MIRANDA: The two codes involved in,
2 RETRAN and LOFTRAN. LOFTRAN is a Westinghouse code.
3 And it was benchmarked -- RETRAN was benchmarked
4 against LOFTRAN.
5 MEMBER WALLIS: That means that they're
6 sort of about the same, but they don't give exactly
7 the same answer.
8 MR. MIRANDA: That's right, they're about
9 the same. And the results --
10 MEMBER WALLIS: So what you could do, is
11 you got two numbers which are close together, you
12 could say I want an independent opinion here. I want
13 a different code to look at this. You don't do that
14 sort of thing?
15 MR. MIRANDA: Well, we do. We use RELAP
16 also. In case we didn't do the RELAP analyses on the
17 non-LOCA events because we just didn't have the time.
18 But right now RELAP is being used by Len Ward to
19 perform small break LOCA analysis.
20 MEMBER WALLIS: But if you were in a
21 hospital and you got some patient, and you weren't
22 quite sure whether or not to do something, you know
23 you might want a second opinion to confirm your
24 decision in some way, you know.
25 MR. FINLEY: Mark Finley.

1 Just to respond to the one question. We
2 didn't cherry pick, so to speak, in terms of the
3 methodology. We made the decision up front to use the
4 RETRAN methodology and that's what we stuck with for
5 the non-LOCA events. We used LOFTRAN for the control
6 systems, so a different functional area at
7 Westinghouse. But we didn't look at the results of two
8 different analyses with two different codes and pick
9 the ones that was better.
10 MEMBER WALLIS: But the Agency has the
11 choice of sometimes doing confirmatory analysis.
12 MR. MIRANDA: Yes.
13 MEMBER WALLIS: Did you pick any of these
14 numbers as being so close that you wanted to see a
15 confirmatory analyses?
16 MR. MIRANDA: Well, as I said before, I
17 did not an analysis of the loss-of-electrical load
18 using the LOFTRAN code. And the results I got were
19 very close to the values that were produced by RETRAN.
20 MEMBER WALLIS: So you did do the --
21 MR. MIRANDA: I did that, yes.
22 MEMBER WALLIS: And what was the number
23 you came up with?
24 MR. MIRANDA: I believe it's in the SER.
25 For the loss-of-load.

1 CHAIRMAN DENNING: And that was with
2 LOFTRAN THINC?
3 MR. MIRANDA: That was with LOFTRAN.
4 CHAIRMAN DENNING: And THINC?
5 MR. MIRANDA: No. THINC was not used in
6 these case.
7 CHAIRMAN DENNING: It wasn't?
8 MEMBER WALLIS: So LOFTRAN is like RETRAN
9 then? Well, maybe you could tell us after lunch or
10 something if you're having difficulty finding it.
11 MR. MIRANDA: I don't know what that
12 number is. The loss-of load event I did was for the
13 overpressure case. The overpressure case, I believe,
14 was 2525 something like that. And that was in another
15 -- okay. Yes. That was to verify that the pressurizer
16 safety valves and the steam generator safety valves
17 were sized adequately. And that value was 2725, which
18 was very close to Westinghouse's number.
19 CHAIRMAN DENNING: And when you worked
20 with Westinghouse -- I'm sorry, you reviewed the
21 Westinghouse analyses, in doing that did you look at
22 inputs and outputs or was this verbal discussion with
23 Westinghouse about them? Did you physically look at
24 the input and output and do some cross checking of
25 that?

1 MR. MIRANDA: Yes. Yes, we did.
2 Westinghouse had available to us the analysts who
3 performed these analyses for discussions. And the
4 analysts brought along the calculations and we looked
5 through the calculations at the inputs and the methods
6 used. Yes, we did that for three days.
7 MEMBER SIEBER: But there is a fair amount
8 of margin built into all of these just by the nature
9 of where they come from.
10 For example in the loss-of-external-
11 electrical load the design pressure of the coolant
12 system, which is really what you're looking at, is
13 2500 pounds for this plant. Normal operating pressure
14 is 2250. During this abnormal occurrence, I think
15 this is an abnormal occurrence type event that's
16 expected to occur perhaps as much as every year, the
17 pressure you can go to is 110 percent of the design
18 pressure by code. But that doesn't mean that that's
19 the ultimate strength of the coolant system. The
20 coolant system ultimate strength, there's tremendous
21 margin between 110 percent of code design pressure and
22 what the ultimate strength is. So that's where the
23 margin really exists. And that doesn't mean don't do
24 your best job to be under this. But it doesn't mean
25 that when you calculate 2750 compared to a limit of

1 2750 that there's no margin left. There's plenty of
2 margin left and it's built into the way the ASME code
3 is designed.
4 CHAIRMAN DENNING: Yes. And that 110
5 percent of design pressure comes an ANSI standard 18.2
6 1993 for condition II events.
7 MEMBER SIEBER: Right.
8 MEMBER WALLIS: I guess what concerns me
9 is the generic problem with codes. Whenever there is
10 a conference on codes, now people are always talking
11 about the user effect; that different people using
12 apparently the same code to analyze exactly the same
13 thing, apparently using the same methods and the same
14 inputs, can often come up with different answers. And
15 the utility has, of course, the incentive to come up
16 with a favorable answer. And it is a user. And so
17 there has to be some careful examination that there
18 hasn't been some user effect which has enabled this
19 code to come very close to whatever is required as the
20 regulatory limit. I think you have to be very careful
21 to ensure that does not happen.
22 MR. MIRANDA: Yes.
23 MR. DUNNE: Jim Dunne.
24 I think one of the things Westinghouse
25 tries to do to eliminate some of the variability

1 associated with the analysts is they have these
2 instruction guidelines for all these different
3 accidents that basically tell the analysts these are
4 the assumptions you have to make and not leave it up
5 to the individual analyst to make that assumption
6 himself.
7 So for a lot of the key inputs
8 Westinghouse has basically standardized internally the
9 assumptions their analysts have to make to remove that
10 variability. And that was, I think, one of the things
11 that the NRC reviewed when they did the audit of
12 Westinghouse in November of last year.
13 MR. MIRANDA: That's correct. And these
14 analysis standards, as they're referred to at
15 Westinghouse have been existence since 1972. I know
16 this because I wrote the first one.
17 MEMBER WALLIS: So you maintain there's no
18 user effect? If we had two different analysts do the
19 same thing, they come up with the same number?
20 MR. MIRANDA: Of course there's a user
21 effect, but these analysis standards are designed to
22 minimize that.
23 MEMBER WALLIS: So how big is the minimum?
24 Is the minimum of variance of 10 percent -- you can go
25 on forever about this. But I'm sure people are aware

1 of this and they've done something, but I just don't
2 have any idea of the dimensions of the uncertainty
3 that remains.
4 MR. MIRANDA: Part of the procedure is
5 that the analysts when calculating the inputs for the
6 codes, it has to follow certain procedures and use
7 certain values that are dictated for that plant. And
8 if he deviates from that procedure for any reason,
9 he's instructed to state the reason and this is
10 reviewed when the calculation is checked by peers and
11 management.
12 Sometimes it's necessary to deviate just
13 because of the plant design. And the analyst should
14 have a good reason for the deviation.
15 CHAIRMAN DENNING: I think you should
16 bounce back now to the continuation of the
17 presentation that you're on and we'll move forward
18 through that.
19 MR. FINLEY: Okay.
20 MR. MIRANDA: This is a listing of the
21 events that the Staff has received analyses for from
22 the licensees. For various reasons, as I said before,
23 in addition to the power uprating.
24 This is followed by events that were
25 evaluated. And the reasons for these events for being

1 evaluated stem from these are either not applicable
2 or they're bounded by other events. Usually they're
3 bounded by other events and a new analysis was not
4 necessary.
5 And this is also stated in the safety
6 evaluation which events are evaluated, which are
7 analyzed. And in the case of events that are
8 evaluated, why it was not necessary to do the
9 analysis.
10 ATWS was also considered. And this event,
11 I thought it was important to review the analysis for
12 this event. There was very little provided by the
13 licensee, by the way, in their submittal concerning
14 ATWS. They said yes we meet the criteria. And I
15 requested to see the analyses and the calculation. And
16 they were provided to me.
17 I considered it important because the
18 Ginna plant has new steam generators, B&W steam
19 generators installed in 1996. And I was afraid that
20 they might be trying to use the Westinghouse generic
21 analyses that originally covered Ginna, which had a 44
22 series steam generators. Without the 44 series steam
23 generator, I believe that the generic analyses no
24 longer applied. And it turns out that Westinghouse
25 had performed an entire new analysis using the new

1 steam generators at the power level of 1817 megawatts.
2 And they obtained an acceptable result.
3 And this 3200 psig is the ASME level
4 stress limit for the weakest component in the RCS,
5 which I believe is the --
6 MEMBER WALLIS: Can I ask you about ATWS?
7 Now other operator actions that occur during an ATWS
8 event which influence the outcome?
9 MR. MIRANDA: The ATWS event is analyzed
10 without operator actions?
11 MEMBER WALLIS: Without?
12 MR. MIRANDA: Without, yes.
13 MEMBER WALLIS: So the operators are not
14 likely to take actions which would change the number
15 of this peak pressure?
16 MR. MIRANDA: The peak pressure occurs at
17 about 2 minutes into the transient.
18 MEMBER WALLIS: And by then the operators
19 haven't done anything?
20 MR. MIRANDA: I don't believe an operator
21 would have a chance to do anything at 2 minutes.
22 MEMBER WALLIS: This is very different
23 from a BWR ATWS where the operators are expected to do
24 things.
25 MR. MIRANDA: As far as new spent fuel

1 storage, Ginna had received an amendment December 2000
2 which permits the credit for soluble boron in the
3 spent fuel pool. And they satisfied also all of the
4 provisions of the 10 CFR 50.68.
5 MEMBER WALLIS: Well the spent fuel pool,
6 rather surprised and maybe not a surprise if I'd know
7 the history of these things. But originally it was
8 capable of taking 210 assemblies and now it seems to
9 be capable of taking -- it has a spec limit of 1879
10 assemblies. So somehow the capacity of the spent fuel
11 pool has been increased by a factor of nine.
12 MR. DUNNE: This is Jim Dunne.
13 I think I can explain some of that
14 history.
15 The 1879 number assumes consolidation of
16 fuel assemblies into consolidated canisters. We take
17 two fuel assemblies approach --
18 MEMBER WALLIS: Well, it's the same the
19 pool. It's the same pool.
20 MR. DUNNE: The same pool.
21 MEMBER WALLIS: So you found ways to
22 increase the capacity by a factor of nine?
23 MR. DUNNE: Right. We've gone through I
24 believe three reracking of our spent fuel pool since
25 the original construction. Our last rereacking was in

1 1998, I believe. And the actual number of storage
2 locations we physically have in the pool right now is
3 up around 1321 fuel assemblies basically. And part of
4 that involved going to boroflex fuel assemblies I
5 think in the '80s.
6 MEMBER WALLIS: Yes.
7 MR. DUNNE: And then in the 1990s we
8 inserted a number of borated stainless steel fuel
9 assemblies --
10 MEMBER WALLIS: So there must have a
11 considerable conservatism in the original design then
12 that you can do this.
13 MR. DUNNE: Yes.
14 MEMBER WALLIS: But now you probably are
15 getting close to a real limit?
16 MR. DUNNE: We are getting close to a real
17 limit, that's correct.
18 CHAIRMAN DENNING: And initially you
19 weren't allowed to take credit for boron in the water.
20 MR. DUNNE: Right. And I think the reason
21 why we took credit for the boron is the boroflex issue
22 and degradation of the boroflex which was either boron
23 poison. But because it's degraded and really not
24 assume it's there, we needed to --
25 MEMBER WALLIS: But we're talking about

1 margin. You're below .95 aren't you, in this case?

2 MR. DUNNE: I believe when we borated,

3 typically we're well below.

4 MEMBER WALLIS: Way below it?

5 MR. DUNNE: Yes.

6 MEMBER WALLIS: Right. So that's not one

7 of these things where you're close to the limit at

8 all?

9 CHAIRMAN DENNING: You take burn up

10 credit?

11 MR. DUNNE: I'll let our fuel engineer

12 answer that one.

13 MR. VERDIN: Yes. This is Gord Verdin.

14 We do take burn up credit and also years

15 of decay due to plutonium decay. And we also have

16 criterion as to the reactivity categories of

17 assemblies that we can place adjacent to each other.

18 That's how we make up for the loss of the boroflex.

19 We don't credit the boroflex at all.

20 MEMBER SIEBER: But the original rules

21 didn't give you a burn up credit, right? And so

22 that's why the spacing was so big?

23 MR. VERDIN: Yes. The other thing was

24 that Ginna back in the 1970s, we actually shipped

25 three regions of the fuel to the West Valley

1 Demonstration Project. There was no intention to leave
2 the fuel in the pool for any period of time.
3 MR. MIRANDA: Okay. These are the results
4 for the large break LOCA using the ASTRUM methodology.
5 And you've seen these numbers before.
6 And finally --
7 MEMBER WALLIS: That's very conservative
8 124 runs. Because the PCT seems to be the one which
9 matters. And so you could do the number of runs
10 appropriate to one criteria. And if you were really
11 satisfied that that was the one that --
12 MR. MIRANDA: Was there a question?
13 MEMBER SIEBER: That's not a question.
14 MEMBER WALLIS: I'm noting that it's only
15 the PCT which seems to come near the limit, so that's
16 the one that governs.
17 MR. MIRANDA: The Staff is still
18 evaluating the small break LOCA analyses and the long
19 term cooling and the boron precipitation. And these
20 are independent analyses being conducted with RELAP.
21 So we don't have the results of those just yet.
22 MEMBER WALLIS: So maybe this is where we
23 get an example of one issue, small break LOCA, which
24 we can go into in some detail instead of rushing
25 through all of these other ones.

1 CHAIRMAN DENNING: Of course, the problem
2 is that one's going to be fair from illumination
3 apparently based on -- so I'm not sure it's going to
4 be--
5 MEMBER WALLIS: So why are we waiting so
6 long to hear something which isn't so important? I
7 was thinking that you might -- that would be your
8 opportunity to show how you go in depth into some of
9 these things because you have more time then.
10 MR. MIRANDA: John Nakoski will address
11 that.
12 MR. NAKOSKI: Yes. This is John Nakoski.
13 I'm the PWR Reactor System Branch Chief.
14 Our intention is at the next Subcommittee
15 meeting where we discuss Beaver Valley to go through
16 what we have done, our confirmatory calculations and
17 the review that we've done for the small break LOCA
18 and long term cooling.
19 Our concern was to develop reasonable
20 assurance that the analysis method and assumptions and
21 the results are consistent with our expectations and
22 satisfy our acceptance criteria.
23 You may be aware that we have a concern in
24 long term cooling for a small break LOCA, that we have
25 reasonable assurance that boron precipitation is not

1 an issue that would impact the Staff's findings.
2 We're evaluating that issue. Ken Ward is doing
3 independent confirmatory calculations. But we have
4 not finished those yet.
5 MR. MIRANDA: In conclusion, the Staff
6 believes that the accident analysis both analyses and
7 evaluations submitted by the licensee, have met the
8 acceptance criteria short of the small break LOCA and
9 the long term cooling of boron precipitation which are
10 still under review.
11 MEMBER SIEBER: I have a question that
12 goes back to the issue of peak clad temperature and
13 design trends through the years. It seems to me that
14 the trend by fuel designers has been to make more rods
15 but smaller rods to lower the linear power density.
16 And in doing that, that had a positive impact insofar
17 as lowering the peak clad temperature.
18 I look at the fuel design trend for Ginna,
19 they're going in the opposite direction. And I
20 presume, you know, they now have bigger, heavier rods,
21 reduced flow, a change in the moderation ratio you
22 know whether you're over moderated or under moderated.
23 And that probably had some negative -- that kind of a
24 design implementation had some negative effect on peak
25 clad temperature, even though you got a lot of margin,

1 I would think that would come out that way? Am I
2 thinking about this in the right framework or not?
3 MR. FINLEY: Let me ask Jeff Kobelak to
4 respond to that, if he would.
5 MEMBER WALLIS: And you told us that using
6 the old method you got to 2070 something.
7 MR. KOBELAK: Yes.
8 MEMBER WALLIS: What would you get to
9 using the old method before the EPU?
10 MR. KOBELAK: We did not run any cases.
11 MEMBER WALLIS: Well, someone must have
12 calculated before because there was a submittal
13 before. It must be in the record somewhere what they
14 were calculating. But they were using some other
15 method even different in those days. Were they using
16 Appendix K or something so we can't make comparisons?
17 MR. KOBELAK: You mean like with pre --
18 MEMBER WALLIS: Well, has the peak clad
19 temperature gone up significantly as a result of the
20 EPU? I think that's sort of the question.
21 MR. VERDIN: This is Gord Verdin.
22 There has been some miscommunication. The
23 2087 is the current best estimate LOCA with the safety
24 methodology at the current power level.
25 MEMBER WALLIS: Without the EPU?

1 MR. VERDIN: That's correct.

2 MEMBER WALLIS: So with the EPU if it goes

3 up, you might have found yourselves up to the limit

4 with the core methodology?

5 MR. VERDIN: Correct. And as we've stated,

6 they didn't actually perform those evaluation at EPU.

7 MEMBER WALLIS: So we can't really make

8 comparisons. But in fact we might have the implication

9 that you used this new methodology because the old

10 methodology was not giving the right answer?

11 MEMBER SIEBER: Or you think it might not.

12 MEMBER WALLIS: Or you thought it might

13 not.

14 MEMBER SIEBER: But whether you thought

15 that or not is irrelevant.

16 MR. FINLEY: Certainly with respect to

17 large break LOCA one of our objectives at the outset

18 was to use the new BE LOCA methodology to demonstrate

19 we had the margin in that analysis for the uprate.

20 Yes.

21 MR. NAKOSKI: And regarding the fuel

22 design, yes, I would say that's an accurate statement.

23 As you increase the number of rods and you lower the

24 linear heat rate per rod, that does kind of benefit

25 the PCT.

1 MEMBER SIEBER: Right. But this design
2 change in the fuel goes the opposite way, which puts
3 more pressure on PCT than you otherwise would have had
4 and you did it for other reasons. That's sort of the
5 way I piece all this together. And you still meet the
6 limit.
7 MR. NAKOSKI: Yes. And the prior fuel was
8 also 14X14.
9 MEMBER SIEBER: Yes.
10 MR. FINLEY: That's correct. Right.
11 MEMBER WALLIS: Well, this would be useful
12 to the Committee to get some idea of is this
13 statistical approach to LOCAs one of the keys to
14 allowing power uprates of this magnitude.
15 MEMBER SIEBER: Yes.
16 MEMBER WALLIS: I think that's an
17 important issue for this Committee to think about. Is
18 that true? Is it true that the statistical approach
19 is enabling this to happen?
20 MR. FINLEY: Yes. That is one of the
21 factors that enables this, yes.
22 MEMBER WALLIS: Yes.
23 CHAIRMAN DENNING: Are you actually done
24 with your part of the presentation and we would have
25 gone to the source terms and radiological consequences

1 next? Is that where we stand?

2 MR. MIRANDA: Yes. I'm done with my part,

3 yes.

4 CHAIRMAN DENNING: Yes. So I think if

5 it's--

6 MR. MILANO: Our presentation is

7 relatively short in that area. And I think it would

8 probably be, if you don't mind, you know we could go

9 through and do that and then have our break.

10 CHAIRMAN DENNING: Would you prefer to do

11 that for some reason?

12 MR. MILANO: Yes. That's what I would

13 prefer to do.

14 CHAIRMAN DENNING: Then we'll go ahead and

15 do it that way then.

16 MR. MILANO: Thank you.

17 Brian?

18 MR. MILANO: This is Brian Lee. he's from

19 our Accident Dose Branch and he's going to make a

20 presentation.

21 MR. LEE: Yes. Good morning. I'm Brian

22 Lee, a reactor systems engineer in the Office of

23 Nuclear Reactor Regulation. Also here with me today

24 is a senior member of staff from the Accident Dose

25 Branch to provide a guidance with me on this review.

1 The Staff reviewed the source terms for
2 rad waste system analysis and reviewed Matrix 9 of the
3 review standard and section 2.9.1 of the EPU safety
4 evaluation.
5 The radiation sources and the reactor
6 coolant were analyzed for EPU conditions under the
7 same methodology previously used in the Ginna design
8 basis, which is consistent with the GALE code that is
9 considered in the Staff's review.
10 Based on the maximum reactor coolant
11 activity product, the staff determined that the EPU is
12 acceptable as it continues to meet the requirements of
13 the 10 CFR Part 20, 10 CFR Part 50 Appendix I, and the
14 General Design Criterion 60.
15 With respect to the design basis accidents
16 radiological consequences analysis, the Staff review
17 Matrix 9 of the review standard and section 2.9.2 of
18 the EPU safety evaluation.
19 The licensee had previously reanalyzed all
20 design basis accidents with the implementation of a
21 full scope alternate source term. The current revised
22 dose analysis assumed proposed EPU conditions at a
23 reactor core power of 1811 megawatts thermal including
24 a two percent power measurement uncertainty and
25 followed the guidance of Reg. Guide 1.183.

1 The Staff took a look at all design basis
2 accidents in its review. The LOCA, the fueling
3 handling accident and the tornado missile accident,
4 which is not considered to a design basis accident but
5 is a part of the Ginna's licensing and design basis
6 were all reanalyzed due to the sources and the fuel
7 increasing at the power increase.
8 The main steam line break, the steam
9 generator tube rupture, the locked rotor accident and
10 the rod injection accident were all reanalyzed due to
11 the change in its mass and energy release.
12 The licensee assumed a control room
13 isolation for all design basis accidents with a filter
14 recirculation flow of 5400 cubic feet per minute. A
15 300 cubic feet per minute unfilter in leakage was
16 assumed and has been validated by a tracer gas in
17 leakage test performed in February of 2005.
18 CHAIRMAN DENNING: When you say confirmed,
19 actually didn't they show that it was substantially
20 lower?
21 MR. LEE: Yes, they did. Actually, their
22 number with one train running the highest load was 21
23 cubic feet per minute.
24 In conclusion the licensee has adequately
25 accounted for the effects of the proposed EPU. All

1 design basis accidents meet the exposure guideline
2 values cited in 10 CFR 50.67 and the acceptance
3 criteria in the Standard Review Plan 15.0.1 for both
4 offsite and in the control room.
5 The Staff finds that the proposed EPU is
6 acceptable with respect to the radiological
7 consequences of design basis accidents.
8 And that concludes my presentation. I can
9 take any questions if you have any.
10 CHAIRMAN DENNING: Questions? No. Thank
11 you very much.
12 Okay. We'll say it's 12:30 and we'll
13 resume here at 1:30.
14 MR. MILANO: At 1:30 is there an
15 expectation that we would continue on with anything
16 with regard to the safety analysis or would we be
17 going to the next item on the --
18 CHAIRMAN DENNING: We'll go to the next
19 item on the list.
20 MR. MILANO: Okay.
21 (Whereupon, at 12:27 p.m. the Subcommittee
22 was adjourned, to reconvene this same day at 1:30
23 p.m.)
24
25

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

2 1:30 p.m.

3 MR. MIRANDA: Could I have your attention,

4 please.

5 Okay. We're going to get started this

6 afternoon's presentations. We're going to start with

7 the risk evaluation summary. And it'll be a two

8 parter. It's going to start out with Ralph Cavedo

9 with Ginna presenting his and we'll follow it with

10 Donnie Harrison from the NRC Staff.

11 Thank you.

12 MR. CAVEDO: Hi. My name is Rob Cavedo.

13 And I've been doing probability risk assessment for 17

14 years. I'm here to present the results of the risk

15 evaluation, results and insights.

16 CHAIRMAN DENNING: You don't have to

17 apologize right at the beginning for saying your risk

18 analyst.

19 MEMBER SIEBER: You can wait a little bit.

20 MR. CAVEDO: Before we go into the

21 original agenda, I just wanted to a tie in to how risk

22 assessment is used to evaluate actual changes in

23 margin.

24 CHAIRMAN DENNING: Move in a little

25 closer.

1 MR. CAVEDO: I'm sorry. I like to move
2 around. I can't do that. I need a wireless microphone.
3 So I'd like to tie in to how the actual
4 risk evaluation relates to actual changes in margin
5 versus calculated changes in margin that you've been
6 referring to a lot.
7 So when you do a typical design basic
8 calculation like loss-of load you'll go through and
9 evaluate the lift setpoints of a bunch of relief
10 valves, for example. And when you determine what you
11 can live with in the calculation, you raise that
12 setpoint until you reach the calculational regulatory
13 limit. But from a risk assessment perspective that's
14 where we go back and look at was that change
15 acceptable. And we look at real plant changes. So if
16 you change an actual setpoint, that's factored into
17 the risk evaluation. And that's where the rubber hits
18 the road and that's where we evaluate what the actual
19 loss in margin is.
20 So I think there is a tie in. We want to
21 have as much operational flexibility as possible, but
22 we want to evaluate what the real change in risk is
23 and make sure that it's acceptable.
24 To perform the risk evaluation we looked
25 at the changes in initiating event frequency, success

1 criteria, equipment failure rates, operator
2 restoration times. And we used that to calculate the
3 change in the core damage frequency in LERF for
4 internal, external events and shutdown.
5 MEMBER SIEBER: Now your success criteria
6 is still a go/no go situation?
7 MR. CAVEDO: Well, the success criteria in
8 a very similar fashion to how the design basis
9 calculations is an iterative process. So for example
10 let's say that you're trying to determine the feed and
11 bleed success criteria. Well, you know a fixed set of
12 equipment that you would like to use and you keep on
13 changing the time that it takes the operator to
14 initiate that action until a certain set of equipment
15 is satisfied. But from a PRA you go beyond just that
16 and say, okay, let's say you had one less PORVs or you
17 had fewer charging. Then you have less time to
18 implement the action. So it's all factored in by
19 calculation to determine time available to perform an
20 action, or in some cases it's break size. So you
21 might go in and let's say it's a large break LOCA,
22 what set of equipment do you need. Let's say that it's
23 medium break LOCA, well you determine those break
24 transition points in terms of piping size based on the
25 amount of equipment that's available. So you turn it

1 into a go/no go problem but it is calculated based on
2 the range of parameters that you examine.
3 MEMBER SIEBER: On the other hand if you
4 have a pump, for example, that is operating right when
5 it's about to lose MPSH, you know maybe you're in
6 recirculation and your strainer's partially clogged.
7 You would count that pump if it doesn't meet the
8 success criteria as inoperable as opposed to a pump
9 that may be chugging and not pumping as much as you
10 would like or as much as advertised?
11 MR. CAVEDO: Right. If the design basis
12 criteria for loss of net positive suction had a sum
13 value, then we might use a different value in the PRA
14 for determining when that pump will actually be
15 failed. Not inoperable, but unavailable.
16 MEMBER SIEBER: Yes.
17 MR. CAVEDO: So we use a terminology as
18 far as the design basis way that you say that it can
19 satisfy the design basis criteria and it's operable,
20 we consider things available to perform their function
21 or not available to perform their function under the
22 given set of circumstances.
23 MEMBER SIEBER: Yes. I think that's one of
24 the drawbacks, at least in my own mind as to how well
25 PRAs model what's going on in the plant.

1 And another one is that PRAs do not have
2 a lot of phenomenological models built into it. And
3 it's relatively simple. And I guess for the purposes
4 that it's being used here by you and by the staff,
5 it's okay. On the other hand, there is plenty of
6 places where PRA modeling could be improved, you know.
7 MR. CAVEDO: There's plenty of places
8 where any modeling could be improved, no matter what
9 you're talking about. That's definitely true.
10 MEMBER SIEBER: Right. That's my speech
11 for this hour.
12 MR. CAVEDO: I mean the Chairman talks
13 about when he talks about PRA and you say is PRA good
14 or bad. And then you say well what are you comparing
15 it to? Design basis. And we all know what the
16 vulnerabilities are with design basis. So it's not
17 whether it's the perfect tool; no one is saying that
18 PRA is the perfect tool. It's just saying it's --
19 well, in my view, it's a better tool.
20 So you have to maintain your design basis
21 margins because that gives you the framework which to
22 evaluate things, but you do need to evaluate what the
23 changes in risk are to make sure that you're operating
24 appropriately.
25 Okay. So we evaluated the impact on those

1 elements to calculate the core damage and load changes
2 on internal events, external events and shutdown risk.
3 There are no PSA initiators as a result of
4 this. Now the reason I mention PRA initiators is
5 because that's different than design basis initiators.
6 Most of the time when you look at a phenomenon,
7 considering the huge number of initiating events that
8 are considered in the PRA, you don't have to make a
9 new initiating event. You just adjust the frequency
10 based on changes as a result of the EPU, for example.
11 So if we had increased flow in the
12 feedwater system and it was beyond certain limits, or
13 not beyond certain limits but it was approaching
14 certain limits, then we might increase the failure
15 rate of that feedwater piping to account for that.
16 As far as success criteria adjustments,
17 which was a majority of the risk. So the small part
18 of the risk was the initiating event frequency
19 changes, the vast majority of the risk changes was due
20 to the change in success criteria. And we used a
21 thermal hydraulic code to evaluate that. And the major
22 impact that we came up with was bleed and feed.
23 We went from pre-EPU to post-EPU, a case
24 where you had to have two PORVs for bleed and feel
25 depending on the availability of charging. So we

1 noticed that was the biggest success criteria change
2 that we had.
3 We did also look at equipment failure
4 rates, but we found is due to the programs that are in
5 place there is not much impact on equipment failures
6 from an immediate mitigation standpoint of an
7 accident. So PRA analysis works 24 hours following the
8 plant challenge. But from a long term perspective
9 because equipment can be operating with less margin
10 available, there is a likelihood that you will have
11 initiating events as a result of the reduced margins,
12 an increasing in the initiating event frequency.
13 MEMBER SIEBER: Do you change your PRA to
14 account for that?
15 MR. CAVEDO: Yes.
16 MEMBER SIEBER: Because I think that's an
17 important thing.
18 MR. CAVEDO: Yes, we do.
19 MEMBER SIEBER: Okay. And how do you do--
20 MR. CAVEDO: Yes. We went through a --
21 MEMBER SIEBER: How do you do it?
22 MR. CAVEDO: Say again?
23 MEMBER SIEBER: How do you do it? By
24 changing the failure rate?
25 MR. CAVEDO: That's exactly right. We

1 change the frequency as a result of that. So what
2 we'll do is we'll do a detailed review of the
3 engineering reports. We'll look at where margin is
4 lost. And then we will adjust frequencies based on
5 that.
6 Now, of course, how do you predict exactly
7 how they're going to be degraded.
8 MEMBER SIEBER: Right.
9 MR. CAVEDO: That's probably the next
10 question that you're worried about. Well, there's no
11 way to predict perfectly what's going to happen. And
12 so with any good risk assessment what you have to do
13 then are sensitivity studies. You look at how all the
14 parameters that are sensitive to this will change as
15 a result of increasing by a factor of two or some
16 metric so you can determine what's sensitive. And then
17 we had, as Dave mentioned, a detailed sequester review
18 where we get everybody together and we talk about it.
19 And we reviewed with the project manager and members
20 of licensing and others all of the parameters that
21 were sensitive. And they were comfortable that those
22 parameters were not going to be adversely impacted by
23 EPU.
24 So the sensitivities give us a feel for
25 not only what the changes are going to be, but to make

1 sure that we're focused on the right areas.

2 MEMBER SIEBER: So you don't really have

3 data? This is a judgment call based on your --

4 MR. CAVEDO: Yes. It's almost exclusively

5 a judgment call because, as you said, data even if you

6 had data for another plant, that might not be

7 applicable to the Ginna plant. And so you could try to

8 do some Basian update, but the sample is so small that

9 it would really not be very relevant, so --

10 MEMBER SIEBER: Right. I think that you

11 realize what the pitfalls are?

12 MR. CAVEDO: Yes.

13 MEMBER SIEBER: It's not clear that there

14 isn't some better way to handle it, but it dominates

15 your lack of data.

16 MR. CAVEDO: And that's why you have to do

17 uncertainty analysis, to make sure that you compensate

18 for your lack of predictability in what's going to

19 happen by looking at -- let's say it's a little bit

20 worse than you think, or let's say it's this; how much

21 does that change the result and would that still be

22 acceptable? So we did a ton of uncertainty analysis

23 to give us comfort that we were still making the right

24 decision.

25 MEMBER SIEBER: Very good. Thank you.

1 MR. CAVEDO: You're welcome.

2 So as I said, the major impact was a
3 change in operator response time. And as was
4 mentioned on a previous slide, obviously the higher
5 decay heat reduced most of the operator response
6 times. And the most important impacts that we noticed
7 was the reduction in time to recover from a loss of
8 shutdown cooling during reduced inventory. And we'll
9 talk about a plant change that we're proposing to help
10 offset that risk.

11 And the next largest one was the amount of
12 the loss of time to recover from a loss of decay
13 removal during a loss of offsite power. And then the
14 one to recovery from a turbine driven AFW pump on a
15 control room complex fire. And so you'll see that the
16 modifications that we're talking about or the plant
17 changes that we're talking about reflect these areas.

18 So here are the results, a sample of the
19 results. This isn't all of them. If you actually
20 looked in the submittal, you'd see that we evaluated
21 all of the actions that could change as a result of
22 the reduction in operator response time due to the
23 increased decay heat. But this just gives you a nice
24 little smattering of what changed.

25 And the important thing to look at here is

1 when you're looking at these times and you go, oh,
2 this is a bigger change in time than the percent
3 change in power, how could that possibly be? Well,
4 these are diagnosis times. So it takes a certain
5 amount of time for an operator to go through a
6 procedure. And that's going to be sometime, ten
7 minutes or whatever it is. So if you reduce the
8 overall time by 17 percent or whatever the calculation
9 shows, because we actually get more margin in the
10 steam generators it's a little cooler, so there are
11 some things which offset each other. But overall you
12 would expect things to be a 17 percent. But because of
13 that subtraction you actually can see bigger
14 percentage changes than you would expect just based on
15 the nature of the power uprate. And that was all
16 factored into the evaluation to calculate what the
17 impact was.
18 MEMBER WALLIS: So are the changes in CDF
19 all due to operator time factors?
20 MR. CAVEDO: Could you say again?
21 MEMBER WALLIS: Are all the changes in CDF
22 due to these changes in time available for operator
23 action?
24 MR. CAVEDO: No. The majority of the CDF,
25 and I've produced a chart in the submittal --

1 MEMBER WALLIS: It seems to be in these
2 EPUs that the hardware changes don't make any
3 difference?
4 MR. CAVEDO: Well, we're going to get to
5 that in a little bit. But the changes that they made
6 actually helped to preserve a lot of the margin. If it
7 wasn't for that, then we would have had a much bigger
8 risk increase.
9 CHAIRMAN DENNING: I wanted to make sure
10 I fully understand the table. What's the right hand
11 column, the steam generator water level at trip?
12 MR. CAVEDO: Well, I could have presented
13 a column with steam generator water levels at other
14 demarkation points. But obviously the more water that
15 you have in the generator at the time of the trip,
16 then the more time you're going to have available to
17 do that. And that's going to damp the impact of these
18 changes. So I just wanted to put that this is at the
19 low level water trip and so these are the conservative
20 numbers. If you look at numbers at a different water
21 level, then you would have more margin.
22 CHAIRMAN DENNING: With regards to these
23 particular events, can you tell us what the
24 conditional failure probability was for the base time
25 versus the EPU time? How much of the failure

1 probabilities changed?

2 MR. CAVEDO: Well, for example for the

3 bleed and feed where you had no charging pumps and a

4 single PORV available, it went from -- I don't

5 remember the specific number whether it was a ten

6 percent chance of failure to guaranteed failure. So

7 that was one of the ones where it went from a

8 reasonable likelihood the operator would succeed to

9 there's not enough time available to perform the

10 action.

11 CHAIRMAN DENNING: Okay.

12 MR. CAVEDO: I did provide all this

13 information in the submittal. And if you want me to,

14 I could look up any specific action that you're

15 curious about, but I don't remember off the top of my

16 head all the changes.

17 CHAIRMAN DENNING: But that's the fourth

18 one down, is it?

19 MR. CAVEDO: That's the one where operator

20 fails to align bleed and feed given a single PORV and

21 no charging. That's the second line down.

22 CHAIRMAN DENNING: Ah, yes. Oh, this is

23 the single PORV?

24 MR. CAVEDO: Yes. Where it's both PORVs

25 they're actually both achievable, so it was just a

1 change in failure probability. But with the single
2 PORV and no charging, it was -- oh, you've got the
3 chart there.
4 So single PORV no charging it went from --
5 well, that was the one that went from guaranteed
6 failure. So there was a 09.7 percent chance of
7 success pre-EPU. With post-EPU it went to guaranteed
8 failure.
9 MEMBER WALLIS: Just by going to 15
10 minutes time?
11 MR. CAVEDO: Yes.
12 MEMBER WALLIS: I mean, he can't do
13 anything in 15 minutes?
14 MR. CAVEDO: Well, there's always the
15 chance that the operator could move outside the
16 procedure or faster than the procedure and achieve a
17 success. But we did tabletop exercises with
18 operations to find out how much time it takes to get
19 to those particular. And it was -- they actually might
20 have been able to do it, but it might have been like
21 an 80 percent chance. And we don't use failure
22 likelihoods. If they're over .5, we typically don't
23 use them for noncurve type recoveries.
24 Does that answer your question? And
25 thanks for this.

1 CHAIRMAN DENNING: Yes.

2 MR. CAVEDO: Okay. And then the next
3 thing we have are the actual results of the EPU change
4 in terms of the internal and external events
5 breakdown. And you can see from this it's about a net
6 change of 7, E-06 for core damage and you can see what
7 the LEF changed. Just do the substraction there.

8 And the percent change in core damage, it
9 actually went up. If we didn't do any modifications or
10 procedure enhancements or improvements to the plant,
11 then the core damage would have gone by 12 percent and
12 the LERF would have gone up by 10 percent.

13 CHAIRMAN DENNING: Can you help us a
14 little bit on what are the principle contributors on
15 fire, for example?

16 MR. CAVEDO: It was the turbine driven AFW
17 pump on the low steam generator water level. So it's
18 a control room complex fire type situation where, of
19 course, there's not much indication available and the
20 turbine driven pump is an important means of
21 mitigating that event.

22 CHAIRMAN DENNING: Yes.

23 MR. CAVEDO: And we are doing
24 modifications in plant improvements along to help
25 support that. So that's not reflected in these

1 numbers. These are the numbers without those
2 improvements in place.
3 CHAIRMAN DENNING: Now are those plant
4 improvements the ones we were hearing about at the
5 very introduction about things that are going to
6 happen that would be risk reducers?
7 MR. CAVEDO: Yes. And I have another
8 slide that talks, and you can see what the specific
9 impacts are of those changes.
10 CHAIRMAN DENNING: Oh, good.
11 Does the pressurizer volume appear as an
12 issue on any damaged states?
13 MR. CAVEDO: Yes. It's not a risk
14 significant issue, but all the stuff that was
15 mentioned in Mark's evaluation, that's all been
16 factored into the risk assessment; the change in boron
17 precipitation, the difference in the pressurizer
18 level, the change of the loss-of load parameters. All
19 of those are factored into the risk assessment. So we
20 did consider increased PORV challenges as a result in
21 the change of the pressurizer configuration. And we
22 did consider slightly increased PORV challenges as a
23 result of loss-of load because above 50 percent it was
24 going to happen anyway and below 10 percent it wasn't.
25 And so we figured out what fraction in between the

1 PORV would be challenged and we figured out what
2 fraction we operated in that plant configuration. So
3 all of that is factored into the risk assessment. But
4 those issues did not play the most significant role.
5 It was all decay heat removal. Change in the operator
6 response time, I mean it's critical operator response
7 time. And so that was the vast majority of the risk
8 increase was as a result of the reduced time for
9 operator response. But all of that information was
10 factored in explicitly in the risk evaluation.
11 CHAIRMAN DENNING: With regards to the
12 potential for vibrational modes of failure of
13 equipment that did not occur that are introduced, is
14 there any contribution as you see it from that?
15 MR. CAVEDO: The initiating event
16 contribution did factor in changes in the vibration.
17 It is our expectation that with our programs in place
18 we are not going to see a risk impact. But until the
19 programs come to fruition, it's obviously when you
20 first achieve that state there may be some
21 degradation. So conservatively we increased the
22 initiating event frequencies based on the items that
23 were mentioned in the engineering report. And it was
24 all judgment based, but then as I said we did the
25 uncertainty evaluation to see what the impact would be

1 possibly.

2 CHAIRMAN DENNING: So you introduced the

3 initiating event frequencies for particular components

4 that presumably would have failed?

5 MR. CAVEDO: No.

6 CHAIRMAN DENNING: No?

7 MR. CAVEDO: We did initiating event

8 frequencies for whole systems. For example, we would

9 increase the loss of feedwater frequency if there was

10 a vibration concern in that whole system. So it

11 wasn't done from a post-trip mitigation standpoint.

12 It was done as an accident initiation.

13 CHAIRMAN DENNING: Yes. But you did it as

14 a system frequency initiator?

15 MR. CAVEDO: Yes. At a initiating event

16 level. And the initiating event are larger than just

17 a component level. The component might not necessarily

18 actually cause an initiating event. There might be

19 actions that could be taken to mitigate that. But we

20 did it at the system level.

21 CHAIRMAN DENNING: Thanks.

22 MR. CAVEDO: Okay.

23 MEMBER WALLIS: I'm a bit confused here.

24 What do you mean? You seem to have said that you

25 increased the risk and then you do some modifications

1 which would decrease the risk so that eventually less
2 than it was before the uprate?
3 MR. CAVEDO: Well, we're jumping ahead,
4 and that's a great lead in.
5 MEMBER WALLIS: So I don't quite
6 understand, what's the difference between --
7 MR. CAVEDO: These numbers don't include
8 any of the plant improvements that we're going to
9 assess later on.
10 MEMBER WALLIS: So these include simply
11 hardware changes or something?
12 MR. CAVEDO: This is just the plant
13 improvements that aren't risk based.
14 So the first thing we did is we did this
15 risk evaluation based on the operational plant
16 improvements that were going to be done, like the
17 condensate booster pump, the standby AFW pump; all of
18 those are factored into these numbers to make sure
19 that we have the same operational configuration which,
20 that obviously provides some risk benefit. If we
21 wouldn't have done that and now a booster pump loss
22 would cause a trip immediately, then that would be a
23 risk increase associated with that. But that was
24 already within the scope to handle that. We didn't
25 consider that from a risk perspective.

1 What we then did was that once we
2 achieved--
3 MEMBER WALLIS: But this business we were
4 talking about earlier about the operator fails to do
5 things. That has changed. That's figured into this
6 slide here?
7 MR. CAVEDO: That is the primary basis,
8 the operator change in times to a 12 percent increase.
9 MEMBER WALLIS: The primarily influence of
10 all this is the operator time to --
11 MR. CAVEDO: I don't remember the exact
12 number, but it was something like 63 percent and then
13 initiating events were 27.
14 MEMBER WALLIS: Okay.
15 MR. CAVEDO: So there you have. He's got
16 the numbers better memorized than I do.
17 MR. FINLEY: Mark Finley again.
18 Just to interject, and what Rob is talking
19 about sort of reflects the timing of how this went.
20 This risk evaluation to this point was done early
21 enough for Rob to identify to us where the risk
22 vulnerabilities were and identify what procedure
23 changes and other modifications might help counteract
24 that. Okay. So this is where we were before he made
25 the recommendations and before we added those

1 additional mods to the scope of the uprate.

2 MR. CAVEDO: So at this point this is what

3 was within the original scope of the uprate. But our

4 management was very interested in preserving our

5 overall margin and keeping our risk levels low. So

6 they said take a look at the most risk significant

7 contributions among your calculations and come up with

8 some procedures enhancement or modifications that

9 could reduce the risk to below the pre-EPU level. And

10 so we did a very exhaustive study and cost benefit

11 analyses with the risk benefit that was available.

12 And we came up with some options. And here are the

13 options that we came up with.

14 Well, first to explain the chart that's

15 there. The first column shows you the pre-EPU risk,

16 and if you look back on the previous one, you see

17 that's just the sum of the internal/external events

18 and shutdown. And then you see what the risk would be,

19 which is also the same as on the previous chart, post-

20 EPU. And then you can see how much the risk goes down

21 as a result of the plant improvements that we're

22 planning. And the aggregate of them is just the last

23 line.

24 So the SI is -- for our Appendix R

25 evaluation we were limited by our existing procedures

1 to just basically crediting the alpha charging pump.
2 But we're doing improvements to make sure that we can
3 credit the safety injection pump for mitigation during
4 our control room complex fire, for example. And so
5 this gives us some risk benefit.
6 And you remember that was one of the risk
7 significant issues was fire. And then the next risk
8 significant issue, actually the most risk significant
9 issue that we found, was during reduced inventory it
10 was possible that air operator control valves on loss
11 of air or power could fail open and cause vortexing on
12 the RHR pumps. And that, of course, in reduced
13 inventory there's not much time available to recover.
14 So that could lead to negative consequences. So we're
15 doing actions to make sure that even on the loss of
16 power or air, the valves will not fail to the point
17 where you'll have that vortexing problem and your RHR
18 pumps will fail. So that, as you can see, was another
19 risk benefit.
20 And then a modification that we're doing
21 is to provide backup air to the charging system so it
22 can maintain --
23 MEMBER WALLIS: Well, I'm lost. I'm lost.
24 Where are these CDF numbers?
25 MR. CAVEDO: This column is the CDF and

1 these are the changes that are --

2 MEMBER WALLIS: Those are changes in CDF?

3 No.

4 MR. CAVEDO: Yes.

5 MEMBER WALLIS: They're awfully big.

6 MR. CAVEDO: So this is what the base

7 changes -- so this is the base change in CDF.

8 MEMBER WALLIS: That's what you had on the

9 previous slide?

10 MR. CAVEDO: And that' what I had on the

11 previous slide. Exactly. And then if you do the

12 safety injection --

13 MEMBER WALLIS: You can get it down lower?

14 MR. CAVEDO: Exactly. Then it goes down by

15 that much. And if you do just the shutdown --

16 CHAIRMAN DENNING: You're saying you could

17 get it down by that much. But you meant it goes down

18 to that much.

19 MEMBER WALLIS: To that much.

20 MR. CAVEDO: Yes, it goes down to that

21 much. Sorry.

22 MEMBER WALLIS: These are separate items

23 them?

24 MR. CAVEDO: Yes.

25 MEMBER WALLIS: If you only do one of

1 these?

2 MR. CAVEDO: Yes.

3 MEMBER WALLIS: But suppose you do them

4 all?

5 MR. CAVEDO: That's the bottom line.

6 MEMBER WALLIS: Oh the bottom line is the

7 sigma. I was just wondering when we'd get to that.

8 MR. CAVEDO: The bottom line is this one

9 right here.

10 MEMBER WALLIS: That's the sum of the

11 whole lot, of three? Okay.

12 MR. CAVEDO: Yes. And that's actually a

13 good lead in to the next slide, if you wanted to go

14 there.

15 CHAIRMAN DENNING: Well, the only thing

16 I've got to say is that we can criticize for lots of

17 things, but we can't criticize you for the mentality

18 of going back and looking at ways to improve safety.

19 MR. CAVEDO: Yes.

20 CHAIRMAN DENNING: So I certainly commend

21 you on that.

22 MR. CAVEDO: So our conclusion is, as was

23 demonstrated by that last slide, is that with these

24 plant improvements in place our risk level post-EPU is

25 actually going to be lower than our risk level pre-

1 EPU.

2 So that concludes this, unless there are

3 any questions.

4 MEMBER SIEBER: Well, that conclusion is

5 based on the fact that you're using surrogates as CDF

6 and LERF as the measure of risk. The real risk also

7 includes the magnitude of the source term?

8 MR. CAVEDO: Yes. To do a level three

9 evaluation.

10 MEMBER SIEBER: Which is probably beyond

11 the practice of PRA the way you all use it. On the

12 other hand it's beyond 1.172 criteria. But I think

13 overall you did a pretty decent job.

14 MR. CAVEDO: Well, one thing to consider

15 with the source term is we are providing an extra risk

16 benefit to the public by producing more power. And so

17 the source term kind of offsets that. The reason we

18 don't talk about the core damage is because if that

19 went up, then of course that is proportional to the

20 source term, which is more consequence.

21 MEMBER SIEBER: That's sort of relative,

22 though. It depends on whether you're getting the

23 increased power or you're getting the source term, you

24 know. It may be two different sets.

25 CHAIRMAN DENNING: Go back one slide here.

1 MR. CAVEDO: Sure.

2 CHAIRMAN DENNING: Down on the bottom line
3 here, I mean we had major fire contributors. As far
4 as the benefit in reduced CDF and LERF, are they
5 fairly evenly distributed among these areas of
6 flooding, I mean proportional to what they were to the
7 core damage frequency initially or is there some
8 particular --

9 MR. CAVEDO: No. The fire and the shutdown
10 took a bigger hit. And you can see that based on the
11 previous chart.

12 CHAIRMAN DENNING: The fire is the one --

13 MR. CAVEDO: The fire in terms of human
14 actions took a bigger hit.

15 CHAIRMAN DENNING: Yes.

16 MR. CAVEDO: But there's something that's
17 interesting in the PRA is if you guarantee fail a
18 bunch of equipment, then of course whether the
19 operator could restore it or not is no longer
20 relevant. So the fire if it fails a lot of equipment
21 just due to the fire, then that's not going to show a
22 big change. But for shutdown where it's a lot of
23 operator action is required to recover from those, you
24 can see that it was a 21 percent change in the core
25 damage frequency because that's heavily reliant on

1 operator actions and it's not so much driven by an
2 outside or an event which damages multiple pieces of
3 equipment at a time. It's just a loss of air, the
4 operator fails to respond in time and then you have a
5 negative consequence.
6 But this is how you can see what
7 specifically was contributing to the risk.
8 CHAIRMAN DENNING: Okay. Any other
9 comments, questions?
10 Good. Well, let's see what the Staff has
11 to say about the risk.
12 MR. HARRISON: I'm Donnie Harrison. I'm
13 magically moving the slides. Okay. We're done.
14 CHAIRMAN DENNING: Well, thank you.
15 MR. HARRISON: There you go.
16 I'm Donnie Harrison. And actually the
17 Ginna analysis presentation makes my presentation a
18 little simpler, because it's amazing two PRA analysts
19 that actually ended up with similar slides.
20 But as part of this review I want to
21 recognize that Otto Basioni was also a key member of
22 the review team. So just as we go through this, it
23 wasn't just one person that did the review; it was
24 actually a couple.
25 I wanted to start off by just giving you

1 the conclusion, which is the Staff believes that the
2 licensee Ginna is adequately modeled and addressed the
3 potential risk impacts due to the power uprate. And
4 the subbullet there, it's from my observation this was
5 the most complete submittal that I've seen to date
6 trying to address the power uprate up front.
7 MEMBER SIEBER: I agree.
8 CHAIRMAN DENNING: Are you saying of the
9 total thing or you mean the risk assessment or what?
10 MR. HARRISON: Yes. The risk assessment
11 portion of the submittal was the most complete that I
12 as an risk analyst has seen. So, yes, don't
13 generalize that comment.
14 Being that it's nonrisk-informed, it still
15 meets the risk acceptance guidelines of Reg. Guide
16 1.174.
17 And during our review we did not identify
18 any special circumstances per the SRP 19 Appendix D
19 criteria that we use.
20 And as you've heard a number of times so
21 far, the licensee's used this analysis to actually
22 identify potential improvements to the plant to make
23 the plant actually safer.
24 CHAIRMAN DENNING: Incidentally, I think
25 that that third bullet is the proper interpretation of

1 -- I think that, you know, these risk-informed changes
2 and I think there are limitations to the 1.174
3 approach to power uprates. But your interpretation at
4 least of the first third bullet, I certainly agree
5 with.
6 MR. HARRISON: And as you said, this is
7 the generic slide that we usually start with just to
8 remind everyone that the power uprate submittals are
9 not risk-informed. However, per the review standard,
10 we get quite a bit of risk information in the
11 submittal. And that information is used in two ways.
12 One is just to determine that the risks are
13 acceptable, and we use the Reg. Guide 1.174 guidelines
14 as a judge on that. But also, we're looking to see if
15 there's special circumstances. And for those not
16 familiar with the process, special circumstances in
17 this case is even though the licensee may meet all the
18 regulatory requirements and may be able to show in the
19 deterministic calculations that everything is
20 acceptable and they meet all their acceptance
21 criteria, if there's some issue that shows up that
22 would make you question the safety of the plant,
23 that's what we're looking for. Has this done
24 something that even though it meets the regulations,
25 it still creates an unsafe condition?

1 MEMBER WALLIS: Now this is completely
2 independent of what we were talking about earlier,
3 these various analyses of various events comparing
4 results with criteria.
5 MR. HARRISON: Right.
6 MEMBER WALLIS: And if the number which we
7 were just looking at which was very slightly below
8 some acceptance criteria for those things have been
9 above it, it wouldn't have shown up in the risk
10 analysis at all. So it's a completely different
11 world.
12 MR. HARRISON: It's a completely different
13 world. That's a correct --
14 MEMBER WALLIS: That's always puzzled me
15 a bit that you can sort of do all this LOCA analyses
16 by different methods and it doesn't really show up in
17 the risk analysis at all.
18 MR. HARRISON: Well, it shows up, but it's
19 using different approaches --
20 MEMBER WALLIS: Different success criteria
21 and so on?
22 MR. HARRISON: Different success criteria,
23 that's right. And --
24 CHAIRMAN DENNING: It's because we don't
25 consider the uncertainty of the success criteria.

1 That's the issue.

2 MEMBER WALLIS: Also it could be because

3 the risk analysis uses very simplified thermal

4 hydraulic models, too.

5 MR. HARRISON: It can be a balance of

6 that. And you may have two PORVs requiring your design

7 basis in the PRA analysis may say one PORV was good

8 enough. So you can have those types of differences. So

9 this is a different world from the deterministic

10 world.

11 And the last bullet on this slide is just

12 to make the observation that we've looked at a number

13 of power uprates, both BWRs and PWRs ranging from 20

14 percent in the BWR world to 17 percent, if you will,

15 for Ginna. And to date we have never identified

16 anything that would be representative of a special

17 circumstances.

18 MEMBER WALLIS: Now

19 MR. WOOD: and Ginna and Kewaunee and

20 similar and they're going to the same power.

21 MR. HARRISON: Yes.

22 MEMBER WALLIS: What's the Kewaunee

23 situation as regards to risk? Is it very comparable?

24 MR. HARRISON: Kewaunee's power uprate was

25 done many years ago, if I remember.

1 MEMBER WALLIS: That was a smaller one?

2 MR. HARRISON: It was a smaller one

3 because I think they started at a higher level. So it

4 didn't take them as much to get up to the 17 --

5 MEMBER WALLIS: Because it's a very

6 similar plant.

7 MR. HARRISON: Because I think this is

8 something like 7 seven percent or 5 percent.

9 MR. DUNNE: Kewaunee was originally

10 licensed to 1650. Basically they had the larger steam

11 generators. This is the series 51 Westinghouse

12 generator versus the series 44 generators that Ginna

13 did. So Ginna was originally licensed at 1520. So

14 when Kewaunee did their uprate, they went from the

15 1650 up to the 1772. And we did our uprate because we

16 now have equivalence series 51 generators, it looked

17 that we used the Kewaunee target as our potential

18 target for doing an uprate. And we rounded it up to

19 1775.

20 MEMBER WALLIS: But their CDF values are

21 very similar to yours?

22 MR. DUNNE: I don't know what -- yes, sir.

23 MR. FINLEY: Yes. I'm Mark Finley again.

24 The Kewaunee -- if you look a the Ginna

25 risk profiles since I developed the original for

1 Ginna, a lot of the risk is driven by fire. And, you
2 know, the non-LOCA, that type of thing. And Ginna
3 also has five aux feedwater pumps, where Kewaunee will
4 have three. And so a lot of the issues for the Ginna
5 secondary site design is what drives the risk profile.
6 So the risk profile for Ginna are Kewaunee
7 are going to be different. You know, the operator
8 timing issues, that type of thing, there will be some
9 similarities there. But, you know, if you look like
10 where cable routing is from a fire concept, that's
11 what drives the risk profile for Ginna. So the cable
12 routing at Kewaunee is going to be different. So
13 therefore, they'll have a different risk profile from
14 a fire standpoint.
15 MR. HARRISON: I think it would be a fair
16 observation, and we'll get to that in a minute, but
17 for most power uprates the observation would be your
18 main impact is going to be operator timing. So that
19 would be a similarity between almost any power uprate
20 that's come before you.
21 The next thing would be initiating event
22 frequencies, you may postulate more trips due to
23 reductions in operating margin.
24 You typically won't see much in component
25 reliability because almost every licensee refurbishes

1 their components or adjust their setpoints or they'll
2 change the motors or and impellers and on their pumps
3 so that they can handle the increased flow rates. So
4 typically they'll make the argument that the component
5 reliability should be comparable pre and post uprate
6 because of that.
7 Sometimes you'll get an impact in success
8 criteria, but those tend to be fairly minor at most
9 plants.
10 This slide just identifies what Ginna
11 covers. You have to recognize that Ginna actually has
12 a PRA or PSA analysis for internal events, external
13 events and shutdown operations. So they have a fairly
14 full scope PRA. Most licensees don't have that.
15 On the level two side they used, at least
16 for this application, the NUREG/CR 6595 simplified in
17 containment of entry approach, which the Staff allows.
18 To give you the risk impacts, this is
19 similar to what Rob presented before. The total CDF
20 increases by 12 percent. The total LERF increases by
21 10 percent. Post power uprate give you the dominant
22 impacts and what their percents were for CDF and LERF.
23 CHAIRMAN DENNING: Did you do SPAR
24 analyses for internal events?
25 MR. HARRISON: In one case. We didn't do

1 a rerun of the SPAR model for Ginna, but we did do
2 that for the situation with seismic events. We took
3 the seismic initiator and put it into the SPAR model
4 to see if we would get a comparable answer to what
5 Ginna got. And we did. We got the same order of
6 magnitude response to that.
7 CHAIRMAN DENNING: But as far as baseline?
8 MR. HARRISON: But we didn't do a baseline
9 recalculation to compare --
10 CHAIRMAN DENNING: No. Recalculation.
11 MR. HARRISON: -- our numbers to their
12 numbers.
13 CHAIRMAN DENNING: What about the baseline
14 itself, the SPAR analysis must be reasonably
15 consistent with the baseline?
16 MR. HARRISON: To be honest with you I
17 don't know. I would have to go back and look. And it
18 would surprise me if it weren't because they did a
19 benchmarking exercise a while back to try to -- in the
20 Reactor Oversight Program they go out to the sites and
21 they benchmark their activities. And in doing that if
22 they find there's a lot of differences, and it's
23 typically the SPAR model that gets adjusted. So
24 they'll adjust it to make them match. So I would be
25 surprised if there was much, but to be honest with

1 you, I can't tell you that, how close the numbers are.
2 CHAIRMAN DENNING: Are we looking at mean
3 risks here? Are we looking at mean of a distribution
4 that's calculated?
5 MR. HARRISON: I would represent these as
6 point estimates.
7 CHAIRMAN DENNING: These are point
8 estimates?
9 MR. HARRISON: Right. And when Rob was
10 earlier talking about doing uncertainty analysis, I
11 would really have characterized those as being
12 sensitivity analysis.
13 CHAIRMAN DENNING: Sensitivity studies.
14 Yes.
15 MR. HARRISON: Where they doubled the
16 frequency or they did other things to try to get at
17 what was important. It was really more sensitivity
18 analysis than uncertainty analysis.
19 MEMBER WALLIS: Are these initiating
20 events? I thought there were no changes in initiating
21 event?
22 MR. HARRISON: No, there were in a couple
23 of different areas. One is the initiating event
24 dealing with the increased flow of main feedwater,
25 main steam. They increased the failure probability for

1 some pipe breaks. So you're going to have increased--
2 MEMBER WALLIS: Okay. As a result of
3 increase or a result --
4 MR. HARRISON: -- now those segments of
5 pipe have been put --
6 MEMBER WALLIS: ==of increase so there's
7 more likelihood of a pipe break?
8 MR. HARRISON: Right. And they've put
9 those into the corrosion/erosion program, but they
10 went ahead and said with the increased flow there will
11 be an increase probability of a pipe -- a segment of
12 a pipe break.
13 There were some other things. There was
14 the ATWS frequency goes up a little bit because all
15 the initiators went up a little bit. If you had
16 increased reactor trip, then you have an increase in
17 the probability of an ATWS. And they increased the
18 reactor trip frequency, so that gives you a connection
19 there.
20 So, yes, there was about a 27 percent of
21 the CDF increases due to initiating events, 63 percent
22 of it is operator reaction timing, recovery timing
23 driven. The numbers here are the same as what Rob
24 provided in his presentation.
25 The one thing I want to emphasize here is

1 Ginna has used this risk evaluation as an opportunity
2 to identify potential changes to make the plant safer
3 that could reduce risk. Now in their submittal they
4 identified what they refer to as risk and cost
5 beneficial changes. They didn't conclude it by talking
6 about the three that they've talked about
7 implementing. But there were a total of five that were
8 originally identified. So don't get too confused
9 between five and three.
10 MR. CAVEDO: This is Rob Cavedo again.
11 MR. CAVEDO: We actually are going to do
12 all of those. The only reason that I mentioned the
13 three in the slide is because they provide the largest
14 risk benefit.
15 MR. HARRISON: And this just gives you a
16 bulletized list of what the five are. Rob's already
17 mentioned three of them. The last two here I think
18 are the ones that weren't mentioned before, which are
19 local controls for the turbine driven aux feedwater
20 pump discharge motor-operated valve and relocating the
21 charging pump control power disconnect.
22 Okay. And we're back to my conclusion.
23 I've got one more slide after this, though.
24 Again, just to reiterate. The Staff
25 believes that the licensee's model, the power uprate

1 correctly using the tools. The risks are acceptable.
2 If this were risk-informed submittal, it would still
3 be acceptable even without the mods that the licensee
4 is making to reduce risk.
5 No special circumstances have been
6 created.
7 And they've used this to identify those
8 five mods that would even further improve risk and
9 make the plant actually from a risk perspective lower
10 than where it is today.
11 And just as a going forward strategy, the
12 Staff sees a need that licensee will continue to need
13 to provide risk information as part of their
14 submittals under the Review Standard 001. However, to
15 better utilize Staff resources, within the Review
16 Standard there's an option that says if we look at
17 what the licensee submits and it looks complete and
18 has addressed all the issues that we can, if you will,
19 truncate our review and we can submit a letter to the
20 project manager and say we've reviewed it, it's
21 complete, you know you can use that information as the
22 Staff input. So it would be a way to truncate our
23 review.
24 We haven't done that to date But going
25 forward as we may actually start to implement that

1 part of the review standard that would let us shorten
2 our review, as long as the licensee provides all the
3 information and it looks complete. So then that would
4 focus our review on just making sure the information
5 is complete and addresses special circumstances and
6 risk acceptability.
7 And just the last bullet. I just want to
8 take this as an opportunity to commend Ginna for
9 actually using the risk evaluation to identify those
10 plant changes that they've called for. It's really
11 easy for a licensee to say we meet Reg. Guide 1.174,
12 we're good enough, let's go. And to see actually a
13 licensee say hey, but we can learn something here and
14 use it, that's worth commending them for. And I would
15 hope that that would be a lesson that they would share
16 with the rest of the industry and that the industry
17 would take that, if you will, as a challenge to say
18 when you do these evaluations, use them and come back
19 and see what you can do to improve your plant.
20 With that note --
21 MEMBER SIEBER: I for one certainly agree
22 with your last bullet. I think this whole piece of
23 this is very well done.
24 CHAIRMAN DENNING: I certainly agree.
25 Thank you very much.

1 MR. HARRISON: Okay.

2 CHAIRMAN DENNING: All right. Now this is

3 where electrical is going to be interjected, is that

4 a true statement?

5 MR. FINLEY: Yes, it is. Yes.

6 I'd like to introduce Joe Pacher, the

7 System Engineering Director from Ginna.

8 MR. PACHER: Hi. I've been at Ginna for

9 about 20 years. I'm SOR certified there. I've been in

10 engineering in a couple different supervisory

11 positions. And before that I did many electrical

12 analysis on the distribution side of the plant.

13 What I'm going to talk about today is our

14 evaluations and some of the modifications we're doing

15 on the power delivery side, and then some of the

16 evaluations we did on our impact on the grid for the

17 power uprate.

18 On the electrical power delivery side, we

19 did do extensive verification and review of onsite and

20 offsite transmission electrical equipment. We did

21 identify, and I'll talk about four specific

22 modifications on the power delivery side that we

23 identified early on our feasibility study that needed

24 some upgrades. And fortunately by identifying them

25 early, it gave us plenty of opportunities to look at

1 industry and to actually do some of the modifications
2 in our 2005 outage and some additional inspections on
3 them. We've been monitoring the performance of that
4 equipment since that time to verify we're going to
5 both maintain adequate margin after uprate and we're
6 going to have reliability after uprate on this
7 equipment.
8 MEMBER WALLIS: Do you ever assess the
9 possibility of switchyard fires? Some plants have had
10 fires int he switchyard. Is this part of your
11 assessment here?
12 MR. PACHER: It's not part of what I'm
13 presenting?
14 MEMBER WALLIS: You're not?
15 MR. PACHER: None of the changes we're
16 doing should impact the likelihood of a fire in our
17 switchyard. The only thing I can think of would be the
18 transformer.
19 MEMBER WALLIS: Right. The transformers.
20 MR. PACHER: Yes. And the transformer,
21 that's the first thing I'm going to talk about. What
22 we have right now it's a three phase 19kV to 115kV
23 transformer. It was installed in 1996, so it's not a
24 significantly old transformer. We installed it in '96
25 based on some gassing increasing we saw in our

1 previous transformer. That transformer has four
2 cooling banks. And like Mark mentioned on, it gave us
3 one cooling bank as a spare. For our uprate we've
4 installed a fifth cooling bank so that we can maintain
5 the same margin. We're not going to see increases in
6 operating temperatures above what we saw before. So
7 our overall risk of a transformer fire shouldn't have
8 increased.
9 So the two things we had to do on that
10 transformer was install the fifth bank and replace the
11 high side voltage bushings. And we did those
12 replacements in 2005.
13 I n addition to doing those replacements,
14 it gave us an opportunity since we had to have the
15 transformer drained to do some detailed inspections,
16 some testing. We had GE come in, spend some time going
17 through the transformer. Replaced all our coolers,
18 replaced all our pumps, replaced the bladder. We did
19 some other inspections. So we got some very high
20 confidence that transformer is going to be reliable
21 after.
22 Based on our OE searches, one of the
23 things we noticed plants were seeing after uprates was
24 they were seeing higher temperatures than expected on
25 the transformer based on local ambient temperatures.

1 We did monitoring last summer and verified that the
2 assumptions that went into our seizing of the fifth
3 cooler in the rating of the transformer were valid
4 based on the temperatures in that area, and we'll
5 continue to monitor it this summer.
6 MEMBER WALLIS: Now what's the interaction
7 between you and the grid? I mean you're producing
8 more power and presumably there has to be some
9 assessment from beyond your plant, which isn't
10 directly your responsibility.
11 MR. PACHER: Yes.
12 MEMBER WALLIS: But you haven't changed
13 the probability of some transient on the grid which
14 would cause you a loss of offsite power.
15 MR. PACHER: Yes.
16 MEMBER WALLIS: There's proper interaction
17 with whatever is responsible for that?
18 MR. PACHER: Yes, there is some
19 interaction. Unfortunately, it's coming up in a couple
20 of slides here, but I'll go into that.
21 MEMBER WALLIS: You were going to go into
22 that?
23 MR. PACHER: The time that we did the
24 feasibility study was the same time Ginna's ownership
25 was being sold to Constellation. So at that point

1 there was a lot of interactions because we were
2 discussing uprate at the time with our local
3 transmission operator, which is Entergy East, to do
4 some detailed evaluations of the impact of our uprate
5 on grid reliability on equipment ratings.
6 Where we're positioned in the transmission
7 system the actual 80 megawatt increase really didn't
8 impact the overall grid reliability. The bar
9 capability of the generator has more impact than the
10 megawatt increase.
11 So they helped us perform those detailed
12 studies. Everything was proven to be acceptable. But
13 there is another study going on right now as part of
14 the New York ISO for the class of 2006 where they look
15 at not just our uprate, but all power increases on the
16 grid in New York. And they're doing various stability
17 studies throughout the system. And at this point
18 they've identified nothing that Ginna would impact
19 that over our good reliability.
20 The second matter I wanted to talk about
21 was the main generator. It's a 19kV generator. When
22 we looked at that generator it was originally rated
23 for 616 MBA to .85 power factor for uprate. We're
24 taking it to 667 MBA. We did some benchmark and we
25 worked with Siemens Westinghouse.

1 That same frame generator is installed at
2 many other places -- not many. Some other places with
3 a 667 MBA rating. The delta for us was our condensate
4 cooler. And we are going to replace our condensate
5 cooler. But our overall windings and design is
6 adequate for the 667 MBA rating.
7 Now knowing that we were going to do this
8 uprate last outage, we did do a major inspection our
9 generator. Our generator has been performing
10 exceptionally. Again, we didn't find any indications
11 that would indicate that we wouldn't have a reliable
12 generator after. But we did do three modifications
13 last outage, including a flux probe, a partial
14 discharge monitor and an intern vibration monitor that
15 we've been monitoring since that during startup and
16 since the outage to verify that the generator is
17 indeed performing reliable.
18 Now those monitors were picked based on
19 some OE searches we did on what failure foods for this
20 type of generator. And we feel that monitoring is
21 going to assure us that we're going to have good
22 reliability on that generator after uprate.
23 MEMBER SIEBER: Does that have a static
24 exciter on it or a rotating exciter?
25 MR. PACHER: It's a rotating exciter. And

1 that exciter we did --

2 MEMBER SIEBER: Old fashioned?

3 MR. PACHER: It's an old fashioned one.

4 Very reliable old fashioned one, but --

5 MEMBER SIEBER: Yes, right. It's more work

6 for the operator.

7 MR. PACHER: Right.

8 MEMBER SIEBER: Changing brushes.

9 MR. PACHER: The third modification we had

10 to do was on our iso-phase bus duct cooler. What we

11 have is a 19kV bus duct. It's service water cooled.

12 Right now there's two fans and both fans operate all

13 the time. There's been significant OE in the industry

14 of plants that have done uprates, Clinton, Vermont

15 Yankee where they've done the uprates and they've

16 increased their fan flow substantially and they

17 experienced delamination of the flexible links that

18 resulted in shorts and plant trips and fires,

19 actually. We looked at their evaluations extensively.

20 For our uprate we have a different type of

21 flex link design, so that failure mode we're not as

22 susceptible to. Last outage we did some detailed

23 inspections of our iso-phase. We had Delta Unibus

24 work with us. We didn't find any issues with our iso-

25 phase, but we did put a focus on out of this uprate we

1 didn't want to increase our cooling flow, our air flow
2 too much that we were going to get into any of these
3 vibration issues. And actually our changes really --
4 if we're going to run the two existing fans that we
5 have right now, we're going to see about a four
6 percent increase in flow. And if we run the third fan
7 we're putting in, we'll see about a ten percent in
8 flow. So our increases in flow are substantially lower
9 than the other plants, both Clinton and Vermont
10 Yankee, who experienced problems.
11 Like I say, we are putting a third cooling
12 fan in. That gives us some operational margin if we do
13 have a trip or a failure of one of the existing fans.
14 It will be a manual action for operations to start
15 that fan. But we won't have to derate for a failure of
16 one fan.
17 The other things we did is the two
18 existing fans that we have, the motors are marginally
19 sized at this point. Sometimes during startups we
20 have some issues with those motors. We are increasing
21 the size of those motors to give us more margin in
22 those motors.
23 I can say throughout the uprate projects
24 there's been many other motors in the plant that we've
25 increased the rate. We've replaced the motors out with

1 a higher horsepower motors to give us some margin. In
2 cases we really didn't need that margin technically,
3 but it gives us some operating margin going forward.
4 Especially given the vintage of our plant, it's a good
5 time to put the newer motors in for reliability out to
6 60 years.
7 MEMBER SIEBER: Do you maintain sufficient
8 margin in interrupt capacity of switchyard circuit
9 breakers and the main unit breakers?
10 MR. PACHER: Yes.
11 MEMBER SIEBER: You checked that, right?
12 MR. PACHER: Yes. We did low flow studies
13 and short circuit analysis.
14 MEMBER SIEBER: Okay.
15 MR. PACHER: Since we're not replacing our
16 generator, we didn't replace the transformer, our
17 actual fault circuits in our switchyard --
18 MEMBER SIEBER: Stays the same?
19 MR. PACHER: -- really haven't changed.
20 And we have adequate margin there.
21 MEMBER SIEBER: Okay.
22 MR. PACHER: The other thing we did on the
23 iso-phase is we are installing some additional
24 indications. We're putting the air temperature on the
25 plant computer so operations has that visible. There

1 will be alarms so they can have some improved
2 monitoring after uprate that they presently do not
3 have.
4 The fourth component we're doing some
5 modifications on is our oil static pipe cable system.
6 We're a little unique in this application. Instead of
7 having overhead transmission lines going from our
8 onsite substation to our substation across the street
9 from this plant, it's an underground oil pipe filled
10 system. It's 4, 8 and a quarter inch pipes with 2000
11 KM cables in there that are -- it's oil pressurized
12 between 180 and 220 pounds. And it's been a very
13 reliable system. It's a static pressurization system
14 right now. No recirculation.
15 When they built the plant they did put
16 recirc pumps in so that they could do recirc flow. But
17 based on the operating temperatures and what the plant
18 was originally sized to, we did not have to put recirc
19 flow. We didn't have to put in service.
20 For uprate we did some detailed reviews of
21 this. Like I said, there's not a lot of nuclear OE
22 experience, so we brought in Underground Systems,
23 Incorporated. They're a company that does a lot of oil
24 pipe systems in non-nuclear applications. They came
25 in, did a complete checkout of our system, did some

1 oil samples. We dug down to the pipe. We examined the
2 coatings. We did some testing to verify the pipe
3 coatings were adequate. And they gave us a clean bill
4 of health on our system. But the temperature studies
5 we've done has indicated that in the peak summer time
6 it will beneficial to go to recirculation mode to keep
7 the temperatures down in the oil. Basically it's a
8 2900 foot pipe, four sets of pipe that go in some
9 shady areas, go in some grassy areas and also go into
10 a parking lot.
11 The parking lot was a particular concern
12 backaches that would be the hottest spot. In that
13 location we did dig down and we put thermal couples on
14 the oil pipe cables under that parking lot. And we're
15 going to tie that to our plant monitor so we can
16 monitor it going forward. And our plan right now
17 based on our studies is that we're going to have to
18 operate that system in recirc for three to four months
19 during the summer time frame.
20 Now we did it operate it last year for a
21 portion of the year to get some operating experience
22 on it. We are going to run it again this summer to
23 make sure that work out any bugs, we can verify it's
24 going to be a reliable system so after uprate we
25 should have a fairly reliable design.

1 MEMBER SIEBER: Now that system, does that
2 work like a transformer oil when you get deterioration
3 and some arcing inside, you form a setaline gas --
4 MR. PACHER: Yes. Yes. And they sampled
5 it this year. IEEE 1406 had some criteria in there
6 that you could give an indication of how much aging
7 you've done on the oil looking at CO_2 levels.
8 MEMBER SIEBER: Right.
9 MR. PACHER: Basically our levels were
10 consistent with an application of less than five years
11 of service. So it was obviously an indication that
12 we've operated this well below its ratings
13 historically.
14 MEMBER SIEBER: Now do you have a
15 procedure in the plant where you sample the oil in
16 this duct system the way you sample oil in the
17 transformer --
18 MR. PACHER: We have not --
19 MEMBER SIEBER: -- to look at it for
20 indicators of incipient failure?
21 MR. PACHER: No. On the transformers we
22 do have online monitors. On the oil pipe system, since
23 it was a static system, samples in the past wouldn't
24 have really given us much because it could have been--
25 you know it depends where the partial discharge was

occurring if it was occurring in the middle of the pipe.

Once we start operating in recirculation mode, that's one of the PM changes we're looking at is what type of frequency we should take samples of that oil and get --

MEMBER SIEBER: Well, this line is not safety related, right?

MR. PACHER: Right. Right. But from a reliability point it's pretty important.

MEMBER SIEBER: Well, even if it trips it doesn't change your lube frequency or anything like that, right?

MR. PACHER: No.

MEMBER SIEBER: And so it's just be a business decision as to the extent to which you wanted to monitor.

MR. PACHER: Right. And obviously anything here I consider pretty critical from a reliability, and I'm sure my bosses think it's pretty critical if something happened to that line after -- we are --

MEMBER SIEBER: That's up to you folks.

MR. PACHER: Yes. I mean, we have gone through all the equipment out in that pump house, both the pressurization system and the recirc system. And

1 like I say, we are going to run it this summer even
2 though we don't need to just to verify reliability.
3 MEMBER SIEBER: Does this go through the
4 apple orchard?
5 MR. PACHER: Yes. Yes. It goes underneath
6 the apple orchard.
7 MEMBER SIEBER: Well don't mess up the
8 apple orchard.
9 MR. PACHER: It's actually a good spot
10 because it's shady there. So it's a good area.
11 As far as the electrical impacts on the
12 grid, I did mention that already. The main generator,
13 we're bound by our interconnect agreement with Entergy
14 East to be able to verify a 100 megabars both leading
15 and lagging. After uprate we will be able to meet
16 that, we will be able to provide 260 megabars out and
17 we'll be able to take a 100 megabars in. So we can
18 meet the requirements. It'd be highly unlikely we'd
19 ever be at the 260 megabars out, but we have the
20 capability in all our components in the power delivery
21 path are now rated to handle that.
22 Like I said, the New York is always
23 working with us doing the class of 2006, they call it,
24 where they're looking at all the generating stations.
25 And the grid can withstand a trip of Ginna during

1 worse case conditions.

2 MEMBER MAYNARD: A quick question on that.

3 Is that true even if you have one -- I don't know how

4 many offsite lines you have coming in, but some plants

5 their line or two of the offsite line is not

6 available, then they have to reduce power because it

7 can't take a trip. Does that apply to Ginna at all?

8 MR. PACHER: We have -- our substation

9 across the street is a 115 kV system, but it does have

10 five separate transmission lines that come into it.

11 Right now we don't have to derate if anyone of those

12 lines go out. There is some contingencies where two

13 lines are on a single pole where we can get into

14 scenarios if lines out, where they might ask us to

15 derate. But at the present time we don't have to

16 derate if any single goes out.

17 MEMBER MAYNARD: Okay. Does the extended

18 power uprate effect that or not? You have the same

19 situation or without the power uprate?

20 MR. PACHER: That's one of the studies

21 we're finalizing right now.

22 MEMBER MAYNARD: Okay.

23 MR. PACHER: But right now the indications

24 are it is going to be -- we won't have to derate after

25 -- with a single line being out. Now there is some

1 upgrades going onto this system planned outside of
2 uprate where they're bring a sixth line in and it's
3 going to even make it more stable. But right now
4 there's no plans to have to derate for a single line
5 being out, pre-uprate or post-uprate.
6 MEMBER MAYNARD: Okay.
7 MR. PACHER: Some other things we're doing
8 that are not uprate related but the timing is work at
9 least noting is we have two offsite circuits coming to
10 the plant, one is an underground fed circuit, Circuit
11 767 has been highly reliable over time. The other one
12 is Circuit 751, which is an overhead transmission
13 line.
14 The overhead line, obviously, is exposed
15 to the elements. We've had failures of that. It's
16 been a concern with us on reliability. We have a
17 modification going on right now that will be scheduled
18 to be done by September to bury that line and feed it
19 underground, too, so that we can get the same
20 reliability on that offsite circuit as we have on 767.
21 The other thing we're doing is right now
22 the control room has curves in the control room to
23 verify voltages in our bar generation to make sure
24 that our post trip voltages are adequate. We are
25 working with our local transmission operator and we

1 have a contract in place with him right now for this
2 summer to have an online contingency monitor. And
3 we're working with him on the protocol on how we
4 communicate those issues. If there's something going
5 on in the transmission system where our post trip
6 contingency voltage is below our limits, our operation
7 shift would be immediately notified.
8 So those are two activities. They're not
9 uprate related, but they are things that we're doing
10 that should improve the reliability of our offsite
11 power and our transmission system post-uprate.
12 The last bullet here was our four hour
13 station blackout coping capability. The uprate didn't
14 really add any significant DC loads, negligible real
15 increase on the DC system. So we haven't impacted our
16 four hour coping capability of our batteries.
17 I do make a note here that last time the
18 batteries came up for PM replacement, when we replaced
19 them we put in bigger batteries. We went from 1200
20 amp hour to 1495 amp hour batteries to give us some
21 additional margin, and obviously that margin is still
22 there. And it's not being impacted by uprate.
23 MEMBER SIEBER: When did the battery
24 replacement occur?
25 MR. PACHER: I think it was 2000. I think

1 it was 2000.

2 MEMBER SIEBER: So these are pretty new

3 batteries.

4 MR. PACHER: Yes, these are pretty new

5 batteries.

6 MEMBER SIEBER: Okay.

7 MEMBER WALLIS: This is the second time

8 we've replaced them. Last time we did 1050s and when

9 we replaced them we went to 1200. So it was a case

10 where we had to do a replacement we wanted to get some

11 margin and we took advantage of it.

12 MEMBER SIEBER: Okay. That's good.

13 MR. PACHER: That's all I have. I

14 introduce Jim Dunne for mechanical impacts.

15 Thank you.

16 MEMBER SIEBER: Thanks.

17 MR. DUNNE: Good afternoon. I'm Jim Dunne.

18 I'm an engineering consultant in the design

19 engineering group at Ginna. I've been in the

20 engineering department at Ginna for approximately 15

21 years. And for the last approximately three years

22 I've been the lead mechanical engineer on the uprate

23 project.

24 Today I want to talk about how the uprate

25 project has effected a number of different mechanical

1 systems and components. Specifically to talk about
2 the impact of upgrade on steam generator vibration,
3 which will also including some discussion on a steam
4 separator designer, even though we don't really have
5 any vibration analysis of our steam generators. But
6 because of the BWR experience, which is why is expect
7 that you would be interested in our separator design.
8 Also review the impact of uprate on the
9 major BOP heat exchanger and the process systems. And
10 the vibration monitoring program that we will be
11 implementing to support uprate from a piping component
12 point of view.
13 Also quickly go over the effect of uprate
14 on the flow accelerated corrosion program we presently
15 have in place.
16 And finally talk about how uprate has
17 effected a number of our existing cooling system,
18 decay heat removal and some others.
19 MEMBER SIEBER: A quick question. When you
20 bought your replacement steam generators, did you
21 specify that you would be operating at this higher
22 steam flow?No
23 MR. DUNNE: No, we didn't.
24 MEMBER SIEBER: So is a reanalysis
25 required --

1 MR. DUNNE: That's correct. And that's--

2 MEMBER SIEBER: -- to qualify the steam

3 separators?

4 MR. DUNNE: That is correct. That gets

5 into my next slide specifically on steam generator

6 vibration. As we stated earlier, our original

7 generators were Westinghouse series 44 generators. And

8 in 1966 we replaced them with new generators

9 manufactured by B&W Canada. Same feed rate in design.

10 The major changes to the generators where we increased

11 the surface area from 44,000 to 54,000 square feet, we

12 changed out the tube material from alloy 600 to 690.

13 And from a steam separator point of view we changed

14 the design moisture carry over number from 0.25

15 percent down to 0.1 percent.

16 As part of the --

17 MEMBER SIEBER: And that's at the old

18 plant rate?

19 MR. DUNNE: Right.

20 MEMBER SIEBER: Okay.

21 MR. DUNNE: So as part of the original

22 uprate or original replacement, B&W Canada was tasked

23 with doing a vibration analysis of the two bundle

24 design where they looked at a number of different

25 areas. For the uprate we have gone back to B&W Canada

1 and asked them to basically revise their original
2 design to take into account the uprated conditions.
3 And for that analysis we gave them conservative
4 bounding estimates to use for their analysis.
5 For example, we expect our steam
6 generator, all that pressure based upon our HP turbine
7 design, to be around 800 psia. And for the uprate,
8 for the reassessment of the bundle we asked B&W Canada
9 to conservatively assume a 750 psia outlet pressure.
10 The lower pressure the maximize the velocity in the
11 two bundle so that we had margin in our analysis.
12 With regard to the original analysis,
13 which is the same as what they have redone, they
14 basically used the ATHOS computer program to calculate
15 the three dimensional flow through the bundle and it's
16 a two phase flow model. They used the ATHOS program to
17 identify areas in the two bundle design that had
18 velocities and also to get the velocity profile
19 density and quality profile within the bundle. Then
20 that --
21 MEMBER WALLIS: Can I ask you these steam
22 generators. Are there other plants using the --
23 MR. DUNNE: Yes.
24 MEMBER WALLIS: -- same steam generator --
25 MR. DUNNE: Yes, there are.

1 MEMBER WALLIS: -- under the essentially
2 the same velocity conditions and so on?
3 MR. DUNNE: Well, there are other plants
4 that have B&W replacement generators. Basically the
5 general design we have is the same design that they've
6 been using for the CANDU steam generators. And there
7 have been a number of U.S. utilities who have bought
8 replacement generators from B&W --
9 MEMBER WALLIS: Well, whatever these
10 analyses show, if you can actually show there's an
11 experience pace which says that these steam generators
12 are not prone to vibration under these conditions,
13 that is also useful information.
14 MR. DUNNE: Correct. And for example
15 there are I believe around 70 to 80 steam generators
16 operating in the world, about 35 or 40 of them in the
17 U.S. including ours that have been operating for
18 periods of time. We've been operating our generators
19 for ten years. And we have not seen any indications
20 of vibration damage or wear in our steam generator
21 bundle consistent with the original analysis. And
22 from my understanding, that's basically true
23 throughout the B&W Canada replacement generator fleet.
24 The types of vibration analyses they did
25 were basically in the area of the two bundle that are

1 exposed to cross flow, which is basically the two
2 entrance region and the U-bend region of the bundles.
3 The types of vibration analyses they did
4 is basically they do a fluidelastic instability
5 calculations both the tube entrance and the U-bend
6 region. They do a vortex shedding analysis only for
7 the tube entrance region because it's an inlet effect
8 and that's really the only place where you have flow
9 entering the bundle. They do a random turbulence
10 excitation analysis for displacements for both the U-
11 Bend and the tube entrance region. And they also do a
12 tube wear analysis for the U-bend. Their experience
13 has been that if you're going to see any tube wear due
14 with wear with supports, it's in the U-bend and not
15 anywhere else in the bundle.
16 So basically they have repeated that set
17 of analyses for Ginna for the uprate conditions. As
18 you would expect with the increased flow we're
19 getting, in general the numbers increase slightly over
20 what we had previously. But for all of the parameters
21 that were investigated, we still met the B&W
22 acceptance criteria.
23 For example, for fluidelastic instability
24 the limiting tube velocity ratio that we have at
25 uprate is .87 with a criteria of less than 1.0. And

1 that compares to, I believe, for the present design a
2 value of around .81 for the same tube location. So you
3 see an increase but we're still below the acceptance
4 criteria.
5 For vortex shedding they use a criteria
6 that the tube displacement for vortex shedding should
7 nominally not be greater than 2 percent of the tube
8 OD. The original analysis we had cut one tube where
9 we were slightly over 2 percent, that they determined
10 was acceptable because of the conservatism in the
11 methodology. At uprate that tube, the displacement
12 has increased slightly but it's gone from like 2.05
13 percent up to like 2.15 percent, a minor change. And
14 it was viewed as still being acceptable.
15 Random turbulence excitation, they use a
16 criteria of 15 mils displacements -- excuse me, 10
17 mils displacement. And none of our tubes either for
18 the present design condition or with the uprate are
19 anywhere near the 10 mil number they use.
20 The tube wear analysis for the U-bend is
21 a little bit different for uprate than was done for
22 the original design. The original design back in 1994
23 and '95 when the generators were being designed by B&@
24 Canada they used a qualitative assessment on tube wear
25 in the U-bend region comparing the Kewaunee thermal

1 dynamic conditions and geometric parameters to other
2 replacement generators or steam generator designs that
3 they had built and they put in service and ranked us
4 compared to other units to basically show that we were
5 bounded by existing units.
6 Since then they've come up with a
7 quantitative method for assessing tube wear in the U-
8 bend. And for our uprate reanalysis, they basically
9 did the quantitative method that they're using
10 presently. Basically their criteria is over a 40 year
11 life of a steam generator that the tube wear due to
12 fretting between tubes and the tube support plates in
13 the U-bend region should not exceed 40 percent
14 throughwall. Their analysis for us at the uprated
15 conditions it showed that none of the wear over a 40
16 year life would exceed 20 percent. So we're well
17 within their acceptance criteria.
18 MEMBER SIEBER: Do you just drilled
19 support plates?
20 MR. DUNNE: No, we don't. We have a
21 basically a lattice grid design.
22 MEMBER SIEBER: Okay.
23 MR. DUNNE: It's completely different--
24 MEMBER SIEBER: Like a combustion
25 engineering --

1 MR. DUNNE: So it's a line interface, if
2 you will, versus you know a full tube interface or a
3 drilled hole interface.
4 MEMBER SIEBER: Okay.
5 MR. DUNNE: So the conclusion of the
6 assessment was that the present design is adequate for
7 the uprated conditions and that there were no other
8 actions that we need to take. We will continue to do
9 our normal monitoring of the tubes per our existing
10 schedule to, again, verify we see no wear or corrosion
11 related indications with the bundle.
12 MEMBER SIEBER: Now you did not discuss
13 the steam separator at the top.
14 MR. DUNNE: Next slide.
15 MEMBER SIEBER: Oh, okay. Well, let me
16 ask a question.
17 MR. DUNNE: Sure.
18 MEMBER SIEBER: And then you can work it
19 into your discussion. In ten years I'm sure you've
20 done the inspections --
21 MR. DUNNE: Yes, we have. We do
22 inspections.
23 MEMBER SIEBER: What did you find.
24 MR. DUNNE: Excuse me?
25 MEMBER SIEBER: What did you find?

1 MR. DUNNE: We didn't find a heck of a
2 lot. We found magnetite buildup on surfaces, but we
3 haven't seen any other indications of wear or any
4 broken welds or anything along those lines.
5 Basically the Ginna steam generators
6 originally with the Westinghouse series 44 generators
7 are primary separators with a swirl vane separators,
8 three big swirl vanes.
9 MEMBER SIEBER: Right.
10 MR. DUNNE: And then our secondary
11 separators were basically a Chevron de-mister type
12 hood, a secondary separator.
13 The B&W design for a primary and secondary
14 separators is completely different than that. They
15 basically use a centrifugal separation for both the
16 primary and the secondary separators.
17 The replacement generators have 85 primary
18 to secondary separator modules installed in the steam
19 dome region.
20 MEMBER SIEBER: Yes.
21 MR. DUNNE: To basically equalize the
22 steam flow over the entire bundle. Also the one
23 feature of that is that it allowed them to do full
24 scale testing of their primary and secondary separator
25 designs at actual operating conditions and steam flow

1 so you didn't have to do any extrapolation from scale
2 testing to figure out the performance of the
3 separators.
4 MEMBER SIEBER: Okay.
5 MR. DUNNE: Based upon the design there's
6 minimum cross flow for the components in the steam
7 dome region. And the way it's constructed, it's a
8 relatively rigid structure which we believe is not
9 susceptible to bundle design.
10 I'll have some slides after I get through
11 these bullets to show a little bit more of the details
12 of the design.
13 And again, as I stated, they have done
14 full scale model testing of these modules for
15 operating pressures between 750 up to, I believe 950
16 psia, for steam flows up to 5800 pounds per hour per
17 module.
18 Presently at our present operating
19 condition our average steam flow is on the order of
20 38,500 pounds per hour. At uprate we'll be increasing
21 our steam flow to around 45,000 pounds per hour per
22 m module. So we're well within the range of steam
23 flows that they have tested these modules at a
24 laboratory.
25 MEMBER SIEBER: And what separation have

1 you gotten so far? .25?

2 MR. DUNNE: When we replaced the

3 generators in 1996 we did a sodium 24 tracer test,

4 basically it was a performance warranty test to prove

5 that they met the 0.1 percent design requirement for

6 the new separators versus the 2.5 percent we have the

7 old. The results of that separator test we're getting

8 moisture carryover rates on the order of .015 to .02

9 percent.

10 MEMBER SIEBER: Okay.

11 MR. DUNNE: So about a factor of five less

12 than the design.

13 Now at uprate we expect actual moisture

14 carryover will increase. Their full scale model

15 testing basically shows that as you increase the steam

16 flow, you tend to get higher qualities. However, you

17 don't really get beyond the 0.1 percent design until

18 you start approaching that 58,000 per hour number per

19 module. So in general we expect that at uprate we will

20 still be well below our design requirement for

21 moisture carryover of .1 percent. We'll probably be

22 down around the .04 to .04 percent range based upon

23 the laboratory test results they have.

24 MEMBER SIEBER: Okay. What's the steam

25 quality of the turbine exhaust?

1 MR. DUNNE: The HP turbine exhaust?

2 MEMBER SIEBER: No. The LP turbine.

3 MR. DUNNE: The LP?

4 MEMBER SIEBER: Yes, that's where you get

5 the wear.

6 MR. DUNNE: Yes. I'm guessing off the top

7 of my head it's around 18 percent. We actually may

8 have higher quality at the HP exhaust. Higher

9 quality, yes, less moisture at the HP turbine exhaust

10 at uprate than we do at the present power level

11 because we're going to have a higher back pressure in

12 our condenser.

13 MEMBER SIEBER: I would think so. I would

14 think so.

15 MR. DUNNE: I don't believe the quality

16 has really changed that much. We're basically coming

17 out at a higher back pressure, but the quality is

18 about the same.

19 MEMBER SIEBER: Okay. Okay.

20 MR. DUNNE: Okay. So just to show you

21 what our steam separators look like, this is an

22 elevation view of the steam drum region of our steam

23 separators. And basically the long riser tube that

24 you see is our primary separator. There is a curved

25 arm separator up at the top. And then you'll see

1 there's a gap and then another set of modules, squat
2 modules all the way up at the top just below the
3 secondary plate. Those squat modules are our
4 secondary separators.
5 In reality even though this drawing
6 doesn't show it, the entire cross section is filled
7 with the separators. So if you go in and look down at
8 the primary separators, what you end up seeing is
9 something that looks like that. Basically what
10 dictates the number of steam separator modules that we
11 install in the steam drum --
12 MEMBER SIEBER: How big it is.
13 MR. DUNNE: -- is how big the steam drum
14 is and how many of these things we can put in.
15 Basically the size of these modules from a diameter
16 point of view is the same for all the uprate plants.
17 And what changes the number of modules from one steam
18 generator versus another steam generator is the
19 diameter of the steam drum.
20 So if you just go in now and look at one
21 individual separator, this is what you see. You see a
22 riser plate at the bottom that is welded to the
23 primary deck. So the steam flow leaving the U-bend is
24 coming out of that riser plate, going up to that
25 curved armed vane separator where you do your initial

1 separation of steam and water. The steam comes up and
2 proceeds upward. The water basically gets spinned out
3 of the curved armed separator, hits the return
4 canister and then drains down the return canister.
5 MEMBER WALLIS: So the purpose of that
6 long riser is what?
7 MR. DUNNE: Well, one of the purposes is
8 to get the primary separator up above the water level
9 in the steam generator.
10 MEMBER SIEBER: Yes.
11 MR. DUNNE: I think that's basically the
12 prime purpose for it. Because the normal water level
13 in the generator may be 4 or 5 feet above the primary
14 deck. And you also want to have it above it so that on
15 operational transients you don't flood out the
16 separator, the primary separator. And basically the
17 testing that was done on these modules basically
18 showed the moisture removal characteristics of the
19 primary separators pretty independent of water level
20 as long as the water doesn't rise into the primary
21 separator themselves.
22 So the return canister is basically welded
23 to the riser tube at the bottom by two plates 180
24 degrees apart. And then the two sets of alignment
25 bolts, one at the bottom and one up near the top that

1 they used to center the riser plate inside the return
2 canister.
3 Now what they end up doing is the primary
4 deck has a stiffener plate welded to the top of it
5 that go across the length of the primary deck to
6 stiffen it up. It's one inch thick steel.
7 The separators have separator ties welded
8 to the outside of them where they basically end up
9 welding adjacent separators to these ties to try and
10 make the entire bundle more rigid. So one separator if
11 it tries to move laterally is transmitting its load to
12 the seven separators.
13 Basically the ties are basically small
14 bore piping, schedule 40 piping. Anywhere from, I
15 believe, maybe one inch up to inch depending upon the
16 location in the tube bundle.
17 The secondary separators, again, it's a
18 curved arm separator where you get steam coming in
19 introducing a swirl to separate the water from the
20 steam. And the steam passes up and then there's a
21 drain tube in the bottom of the box that collects the
22 water and drains it back to the == basically, the
23 water side of the generator.
24 The curved arm separators are welded to
25 the separator plate that's above it. The separator

1 plate is basically half inch carbon steel plate and
2 it's got stiffeners underneath it running from one end
3 to the other laterally. And in between those there are
4 spacers that go from one separator to another to make
5 it a very rigid structure.
6 MEMBER SIEBER: It seems like it would be
7 hard to inspect.
8 MR. DUNNE: Actually, let me go back --
9 MEMBER SIEBER: Do you use a baroscope or
10 something?
11 MR. DUNNE: What you end up doing, there's
12 a manway at the top --
13 MEMBER SIEBER: Right.
14 MR. DUNNE: -- of the steam generator. We
15 can enter that manway and basically get into that
16 steam dome region.
17 MEMBER SIEBER: Right.
18 MR. DUNNE: And that allows us to inspect
19 the secondary deck plate and we can also inspect all
20 t hose secondary separators because we can look down
21 into that.
22 MEMBER SIEBER: Right.
23 MR. DUNNE: There is always, and you don't
24 see it here, but down in the bottom there's a boxed
25 area over by the feed ring, that's basically a ladder

1 access that allows us to climb down through the
2 separator bundle. It's primarily there to allow us to
3 access the U-bend region of the steam generator. But
4 we can also as we go down there look in at those
5 modules.
6 MEMBER SIEBER: With all those welds in
7 there, it doesn't look like you could go and inspect
8 them.
9 MR. DUNNE: No. No. We really can't go in
10 and inspect the welds on those separator ties, for
11 example.
12 MEMBER SIEBER: Right.
13 MR. DUNNE: So if you go in and compare
14 what we have to what we understand the BWR steam
15 generators look like, and this is sort of similar to
16 the criterion that I think Waterford used to the full
17 ACRS. As a matter of fact, that's where we stole their
18 BWR cartoon. But the design and the flow patterns
19 basically are completely different.
20 We believe we have a rigid structure to
21 begin with. And basically whereas they had flow
22 patterns that were inducing a lot of turbulence in the
23 reactor vessel head trying to work its way over to the
24 main steam nozzle, we basically have a uniform flow
25 path going to our main steam nozzle so we don't

1 believe we're going to get turbulence within the
2 bundle that would cause any flow induced vibration on
3 our steam separating system.
4 MEMBER SIEBER: There is an advantage of
5 having the steam outlet at the top as opposed to the
6 side where you have to --
7 MR. DUNNE: That's where the steam wants
8 to go.
9 MEMBER SIEBER: Yes. Correct.
10 MR. DUNNE: So that's basically what I
11 have on the steam separators for Ginna.
12 CHAIRMAN DENNING: Do you have vibration
13 monitors downstream that could pick up a vibration if
14 one were to occur.
15 MR. DUNNE: No. We don't have vibration
16 monitors installed on our main steam piping. As part
17 of vibration piping monitoring program we may be
18 installing some monitors for the power escalation on
19 the main steam line to monitor data. But in general we
20 don't monitor vibration on it.
21 Now one thing we do have if we had a loose
22 part and it fell down into the bundle, we do have an
23 acoustic monitoring system on the tube sheet region of
24 our steam generators which basically would alarm in
25 the control room if it got any acoustic signals that

1 were outside its normal range. It's primarily intended
2 to tell us that we've got a loose part basically in
3 the bottom of the bundle design that may be causing a
4 wear indication.
5 MEMBER MAYNARD: And I would think that if
6 you had vibration especially if it was causing any
7 contact between any points, that monitoring system
8 would pick that up.
9 MR. DUNNE: Depending upon -- possibly.
10 I don't want to say conclusively that if we had any
11 vibration it would pick it up. I think if we had any
12 major issues due to the parts that fell off that were
13 rattling around in the U-bend or in the steam
14 generator, we would hope that that acoustic monitoring
15 system would notice a change and alarm and force us to
16 go figure out why it alarmed on us.
17 MEMBER SIEBER: I noticed in one of the
18 pictures, and this isn't a safety issue either, that
19 from the feed drain you don't have the old
20 Westinghouse design --
21 MR. DUNNE: No. We have a gooseneck design
22 so that instead of the feedwater nozzle --and so the
23 feedwater coming horizontally into the feed ring and
24 then feeding out, and the original design had the
25 holes in the bottom which caused steam generator water

1 hammer problems and then we went to J-nozzles. We have
2 J-nozzles on our feed ring, but instead of coming
3 directly into the feed ring, we come in and we have a
4 gooseneck piping that goes up and comes down.
5 MEMBER SIEBER: Like a trap?
6 MR. DUNNE: To trap it and minimize,
7 basically, draining the header and causing a steam
8 generator water head issue.
9 MEMBER SIEBER: Yes. I thought I saw that
10 on the drawing.
11 MR. DUNNE: That was one of the features
12 associated with the new replacement generators over
13 the old design.
14 MEMBER SIEBER: Yes.
15 MEMBER WALLIS: Is a gooseneck the same as
16 a J-tube?
17 MR. DUNNE: Possibly.
18 MEMBER WALLIS: Isn't it really the same
19 thing?
20 MR. DUNNE: I always called it a
21 gooseneck, but it's basically a U-bend basically type
22 deal.
23 So if there aren't any other questions, I
24 will move on -- if I can figure out where I am. Okay.
25 Balance of plant heat exchanges.

1 Basically, obviously increasing flows around the
2 process piping and the main feedwater, main steam
3 extraction steams we're increasing mass flow rates to
4 our feedwater heaters.
5 Ginna has two trains of feedwater heaters,
6 each train has five feedwater heaters, four low
7 pressure heaters and one high pressure heater. Three
8 of our four low pressure heaters basically have a
9 drain cooling section, one of them doesn't it's just
10 a condensing heater design.
11 So as part of the uprate and based upon
12 the operating experience out there from past uprates
13 where people have had vibration problems after uprate
14 with their heat exchanges, we basically contracted
15 with TEI, Thermal Engineering International which is
16 the old Southwest Engineering, to go back and do an
17 assessment of our existing feedwater heaters at the
18 uprated condition. Basically Ginna has changed out
19 all of the tube bundles in our existing feedwater
20 heaters. We originally had cooper alloy tubing and as
21 part of steam generator corrosion from the early '80s
22 up to 1995 we're in the processing of retubing our
23 heat exchangers.
24 TEI or Southwest Engineering was
25 responsible for providing three of the five new tube

1 bundles, so they were very familiar with that design
2 because it was theirs. And the other two were Marley,
3 who I guess had gone out of business, but they had
4 access to their design information.
5 So we asked them to review the feedwater
6 heaters for uprate from both a vibration point of
7 view, velocity point of view, thermal performance
8 point of view.
9 From a vibration point of view basically
10 their conclusion was that there is no concerns with
11 vibration in the condensing zone region of the
12 feedwater heaters. They were more concerned about the
13 potential for vibration in the drain cooling section,
14 so they did detailed calculations for fluid elastic
15 instability in the drain cooling section. Their
16 conclusions were that on all four of the feedwater
17 heaters that have drain cooling sections that the
18 velocity was below the critical velocity.
19 They had one concern because their normal
20 design practice for a new feedwater heater is to
21 design it to a velocity ratio of 0.75. And we had one
22 set of heaters, our number 5 feedwater heaters which
23 are our high pressure heaters, where our velocity
24 ratio at uprate actually exceed .75, I think it was
25 around .82, .82. their recommendation was that they

1 believed it was okay to go forward, but they
2 recommended monitoring those feedwater heaters going
3 forward to make sure there is not an issue.
4 So what we are done and we are basically
5 getting baseline examinations, eddy current
6 examination for the drain cooling sections of our two
7 number 5 feedwater heaters prior to uprate. We did one
8 of them last year, we're going to do the second one
9 this year so that we have a good comparison point.
10 The last time we had inspected those
11 heaters were back in 2002 as part of our normal heat
12 exchanger inspection program. And the one we looked at
13 last year when we compared the eddy current results to
14 the previous one in 2002, we did not see any changes.
15 So the expectation is the second one that we do this
16 year we'll see the same thing. But we'll have a clean
17 baseline for assessing what we see after we do the
18 uprate.
19 So the plan is that the first refueling
20 outage after uprate we will go back in and do an eddy
21 current examine both those heat exchangers to confirm
22 that there are no indications of vibration damaging
23 occurring.
24 The second set of major heaters effected
25 by uprate are our moisture separator reheaters. We

1 have basically four reheaters. We have single stage
2 reheating, but we have four MSRs. Again, they were
3 retubed in the early 1980s, again, to get cooper alloy
4 out and I think to put stainless in.
5 Additionally, we have had problems with
6 the reheater design on thermal performance. And we
7 thought we were getting excessive carryover moisture
8 from the separator into the bundle design, which is
9 probably why we were having thermal performance issues
10 with the steam outlet temperature.
11 TEI or Southwest Engineering at the time
12 was responsible for designing those new tube bundles.
13 So we went back to them to ask them to update their
14 analyses for the uprated conditions. They redid their
15 analyses for the uprated conditions and their
16 conclusion was that the design was acceptable. We had
17 around 15 to 20 percent margin between the velocity
18 and the critical velocity.
19 The final major heat exchanger in the
20 system is the condenser. We retubed our condensers in
21 1995, replaced tubing with stainless steel tubing. As
22 part of that tube bundle replacement in '95, we staked
23 our entire tube bundle.
24 Stone & Webster evaluated our condenser
25 for uprate on tube span for the uprated conditions

1 using the methodology in HEI for condenser design for
2 maximal allowable span. And the calculations concluded
3 that we had adequate spacing presently based upon the
4 calculations. And the only reason why that's the case
5 is because we staked the bundle in '95. If we had not
6 staked the bundle in '95, we would have had to have
7 done a condenser staking operation to support uprate.
8 The other vibration program we have is the
9 vibration monitoring program, which is primarily for
10 piping that we will use to assess potential impact of
11 uprate on piping vibration. It's basically composed of
12 two parts, like everybody else who has probably come
13 before you. Basically a pre-EPU assessment of
14 vibration levels in the process piping systems; main
15 steam, main feedwater extraction, reheater a couple of
16 others. But all the systems that basically see
17 increased flow due to uprate.
18 And basically there's a two part baseline.
19 It's an initial walkdown, visual walkdown of the
20 system to identify areas where there are possibly
21 noticeable indications of vibration. We did that with
22 Stone & Webster, I believe, last week. And they're
23 putting the results of the walkdown together. And then
24 based upon that we're going to identify locations
25 where we have vibration levels that we think we need

1 to monitor going forward. We'll put monitoring
2 equipment on, be it handheld or permanent will depend
3 upon the location, and get a baseline indication of
4 what the vibration level is presently. And then after
5 we come out of our uprate outage we will basically
6 repeat that process, do the visual walkdown again to
7 verify that we don't see any new indications of
8 vibration. And also to go in and compare those places
9 we monitored now, to monitor them again at EPU and
10 assess any changes in vibration levels. And then
11 depending upon what we'll see, we'll evaluate the
12 results and take whatever actions are appropriate if
13 there are any areas where we see vibration that we
14 need to basically deal with.
15 CHAIRMAN DENNING: I'm not quite
16 understanding. Are you talking about monitoring
17 instrumentation?
18 MR. DUNNE: We will install -- yes, be it
19 an accelerometer or a displacement probe or velocity
20 probe. We haven't figured out exactly what we're going
21 to install, but we are going to put monitoring
22 instrumentation at select points. And we haven't
23 figured out the list yet because it's going to be base
24 don our visual walkdown on the system that we will
25 then go in and present instrumentation values be it

1 acceleration velocity or displacement. And then
2 repeat that at those same locations at the EPU
3 conditions to assess deltas, if you will, due to the
4 uprate.
5 MEMBER SIEBER: This is portable
6 instruments or permanent ones, or you don't know?
7 MR. DUNNE: We haven't decided yet. It
8 may be a combination of both. It may be all portable,
9 it may be a combination of portable and permanent.
10 We have used operating experience in
11 setting up our monitoring program. And specifically
12 Stone & Webster has been involved in a lot of uprates
13 where they have done this activity and so whatever
14 they've learned from all the walkdowns they've done,
15 they've incorporated into the program.
16 We've also gone through basically action
17 report condition reports at Ginna to figure out any
18 areas where historically we may have noticed vibration
19 to make sure that review those and assess them going
20 forward. And we also have reviewed the other
21 operating industry experience reports that are on INPO
22 to see what other lessons learned we should
23 incorporate into our program.
24 For example, someone a couple of years ago
25 and came out and they had an instrument to basically

1 fail. We're making sure that our visual walkdown
2 includes all branch lines including instrumentation
3 off of the main process lines that are seen in the
4 high flows.
5 MEMBER SIEBER: Now do you have motor
6 driven or steam drive feed pumps?
7 MR. DUNNE: We have motor driven.
8 MEMBER SIEBER: And so at low power levels
9 you're putting a big pressure drop across your feed
10 reg valves?
11 MR. DUNNE: That's correct.
12 MEMBER SIEBER: You get a lot of vibration
13 there?
14 MR. DUNNE: We probably do. Typically we
15 don't go in and monitor at transient operating points
16 because typically you will get higher vibration levels
17 than you will at your normal operating point. That
18 the last --
19 MEMBER SIEBER: That's usually when the
20 valve falls apart.
21 MR. DUNNE: Yes. So that's the last
22 portion of the monitoring program.
23 We do have a rotating machinery vibration
24 program presently which involves periodic monitoring
25 of the major rotating components in the plant,

1 basically the feed pump, heater drain pump, circ water
2 pump, condensate pump, etc. Right now that's
3 monitored on a monthly bases. We have baseline
4 vibration readings for the pumps, the motors for our
5 main feed pumps. We have a speed increaser between a
6 motor and the pump. We monitor vibration from that
7 component. So we have that baseline.
8 And typically after any refueling outage
9 our rotating equipment analyst goes around and
10 basically walks through all those components to make
11 sure there's been no change versus what our values
12 were before We will be doing that activity as part of
13 our power accession program.
14 MEMBER SIEBER: Now I think I read where
15 you're replacing motors or pumps in your feedwater
16 system?
17 MR. DUNNE: We are putting new main feed
18 pump impellers into our existing pump casings to
19 basically get increased capacity. Because of that
20 increased capacity we're putting larger sized motors.
21 So we have to rebaseline those components anyway to
22 get a new baseline reading.
23 We're also putting in new impellers in our
24 condensate booster pumps.
25 MEMBER SIEBER: And your output pressure

1 for the pumps will be higher because T_h is higher?

2 MR. DUNNE: Our T^h is higher. Our steam

3 drainer pressure is going to be slightly higher than

4 when we operate now, but not appreciably. Right now

5 we run with a steam generator outlet pressure on the

6 order of around 770 psi at the steam generator nozzle.

7 And at uprate we expect that that value will go up to

8 800. Basically what we're trying to do is increase

9 the steam generator pressure to cover the increased

10 frictional loss in the main steam line so that the

11 inlet pressure to our turbine --

12 MEMBER SIEBER: Right. It about the same?

13 MR. DUNNE: -- is basically the same as

14 what we have right now. And it's the turbine design

15 that controls that.

16 MR. DUNNE: That's going to put more

17 pressure on your fed reg valve.

18 MR. DUNNE: Right. Now what we need to do

19 is because the main feed pump impeller was going to

20 give us comparable pressure drop characteristics to

21 what we have presently. But right now we throttle out

22 of the system about 200 psi across our main feedwater

23 valves. So what we're basically doing is putting --

24 MEMBER SIEBER: Is that all? I would think

25 it would be more than that.

1 MR. DUNNE: Yes, it's around -- I think
2 it's around 200.
3 MEMBER SIEBER: At full power?
4 MR. DUNNE: Yes. Full power. Yes.
5 MEMBER SIEBER: Okay.
6 MR. DUNNE: Okay. Yes, at low power it's
7 a very large number.
8 MEMBER SIEBER: Okay.
9 MR. DUNNE: Actually, at low power it may
10 not be as large as you think because at low power the
11 steam generator pressure is higher.
12 MEMBER SIEBER: Right.
13 MR. DUNNE: At zero power we run a 1,000
14 psi. But you got more head -- you got more head on --
15 MEMBER SIEBER: It's nearly closed.
16 MR. DUNNE: Right. You've got less flow
17 and you got more head on your pumps, you got a larger
18 pump discharge pressure.
19 MEMBER SIEBER: Yes. Well, it's something
20 for you to watch.
21 MR. DUNNE: Yes. And that's all I had on
22 the vibration monitoring program.
23 The next thing I want to quickly go over
24 is flow accelerated corrosion program. Ginna does
25 have a flow accelerated corrosion program presently

1 that we're maintaining. It basically involves the
2 CHECWORKS, EPRI CHECWORKS computer program in
3 combination with actual plant readings on wear rates
4 on the various components are a part of the system.
5 And eery outage our flow accelerated corrosion
6 engineer goes around and has probably 100 or 200
7 components that he identifies to go in and get actual
8 thickness readings so he can assess what the change in
9 wear rates has been. And then he rolls that back into
10 his program.
11 Obviously with increased flow rates
12 changes in pressures and temperatures and quality in
13 your piping systems you would expect there's a
14 potential impact on the corrosion rates.
15 For the uprate what we've done is we've
16 taken the CHECWORKS program and used it to
17 analytically predict the wear rate based upon the
18 existing process conditions. And then go in, put in
19 the new uprate conditions and look at a change in wear
20 rate, an analytical wear rate.
21 And in our submittal, if I can get this
22 thing to work, we included this table in our licensee
23 submittal to the NRC where we went around and
24 basically tried to touch all the major systems that
25 are part of the FAC program and look at components

1 that have wear rates presently to assess what the
2 change in the wear rate would be analytically due to
3 the EPU conditions. So I believe it's the column all
4 the way over at the right that tells you the percent
5 change and the wear rate due to EPU. And the numbers,
6 depending upon the system, vary anywhere from about 2
7 or 3 percent up to as high as 24 percent.
8 MEMBER WALLIS: So it's the extraction
9 steam line that's the most sensitive here, the one
10 that's wear in the fastest?
11 MR. DUNNE: And that may not be too
12 surprising. That's a wet system.
13 MEMBER WALLIS: It's because of the
14 materials that you're using, too, isn't it?
15 MR. DUNNE: It could be.
16 MEMBER WALLIS: It's two phase?
17 MR. DUNNE: It's two phase, and that
18 probably has a large part to it. We've gone through
19 the plant and have changed out a lot of materials from
20 the original material that was susceptible to wear to
21 basically a chrome molly material.
22 MEMBER WALLIS: So how long are they going
23 to last, these pipes now?
24 MR. DUNNE: Well, that will depend upon --
25 MEMBER WALLIS: Your 5 mils per year or

1 something you're losing?

2 MR. DUNNE: It depends upon where you're

3 talking. Which component?

4 MEMBER WALLIS: It's not changed all that

5 much?

6 MR. DUNNE: No, it doesn't. So basically

7 what's happening is we're in the process right now --

8 if I can get out of this.

9 MEMBER WALLIS: Well, it's not really a

10 safety issue?

11 MR. DUNNE: No.

12 MEMBER WALLIS: It would be embarrassing

13 to lose a section of steam line, but it's not really

14 a safety issue.

15 MR. DUNNE: I guess a couple of things I

16 would like to say is that --

17 MEMBER SIEBER: It's not a nuclear safety

18 issue. Personnel safety more than nuclear safety.

19 MR. DUNNE: Basically we have added

20 components to the FAC program based upon the uprate.

21 For example, the piping between our number two

22 feedwater heater outlet and on our number 3 feedwater

23 heater inlet is presently out of the program because

24 the temperature doesn't exceed 212 degrees. It's

25 around 208, 210. At EPU it's going to be over 212.

1 So it's in the program now. Now it's basically about
2 five feet of pipe, there isn't much there. But we will
3 be adding that to the program.
4 And also based upon the analysis of the
5 feedwater heaters that was done by TEI, we have a lot
6 of feedwater heater nozzles where we have high
7 velocities. Most of those nozzles are already in our
8 emersion corrosion program because of temperature and
9 quality, but there were a number of them that weren't.
10 For example, our low pressure feedwater heaters that
11 see 150/160 degree water would be out of the program.
12 We are adding them into the program because of high
13 velocity to monitor wear on those nozzle due to the
14 increased velocity that we see under EPU conditions.
15 So we do not have any components that need
16 to be replaced. We will be increasing the number of
17 components that we basically sample going into our
18 2006 refueling outage. That will be at the discretion
19 of our emersion corrosion engineer based upon what he
20 sees after he updates his entire program. And then
21 going forward we will monitor components and look at
22 actual wear rates based upon plant data and assess our
23 inspection frequency as needed.
24 Okay. The final thing I'd like to quickly
25 do is go through and just go over what effect the

1 uprate has had on our various cooling systems, they're
2 primarily safety related cooling systems.
3 The approach we took at uprate going into
4 it was to assume that all of our cooling systems would
5 function the same as they do right now. Do all the
6 evaluations based upon the existing cooling capability
7 and then assess whether that was adequate or whether
8 changes needed to be made to the system. And that's
9 the approach we took. So what this basically does is
10 tell you where we found out we didn't need to make
11 changes versus where we had to make changes.
12 Safety injection system, which is
13 primarily used for large break/small break LOCAs, we
14 used the existing flow capability that we have for the
15 present operating condition. And basically based upon
16 the Pclad temperature numbers we're getting, there's
17 no need to change flow capability.
18 Additionally contain the spray system
19 which is for containment pressurization. We used the
20 existing design flow capability. And, again, since we
21 were able to show that containment pressure are below
22 design, there was no need to change its functional
23 requirements.
24 Aux feedwater system. At Ginna --
25 MEMBER WALLIS: So many plants have upper

1 plenum injection.

2 MR. DUNNE: Excuse me?

3 MEMBER WALLIS: You have upper plenum

4 injection --

5 MR. DUNNE: Yes, we have upper plenum

6 injection.

7 MEMBER WALLIS: -- which is rather

8 unusual.

9 MR. DUNNE: We are rather unusual.

10 MEMBER WALLIS: Are there many other

11 plants that do that?

12 MR. DUNNE: There are a couple. Kewaunee,

13 I believe, has it.

14 MEMBER WALLIS: Well, it's just a few,

15 very few?

16 MR. DUNNE: Just a few, yes.

17 MEMBER WALLIS: All right. It's not an

18 issue, I was just curious.

19 MR. DUNNE: No. We are an upper plenum

20 injection plant.

21 Our aux feedwater system, we actually have

22 two aux feedwater systems. The preferred aux

23 feedwater system and a standby aux feedwater system.

24 And as mentioned earlier, we have a total of five

25 pumps in those two systems.

1 Our preferred aux feedwater system has two
2 motor driven aux feedwater pumps, nominal design
3 requirements of 200 gpm. And they're aligned to
4 individual steam generators. And then our turbine
5 driven aux feedwater pump is a 400 gpm system that
6 basically is supposed to deliver 200 gpm to each
7 generator.
8 Because of potential high energy line
9 break concerns since all our aux feedwater pumps are
10 in the same general area, there was a potential for a
11 high energy line break that could take out all the
12 pumps. In the mid-'70s we added a separate standby aux
13 feedwater system which has two more 200 gpm pumps
14 completely independent of the preferred. It's
15 basically pumps that we never operate. They are
16 basically a backup to our preferred aux feedwater
17 pumps. We don't use them for normal plant cool down or
18 anything. They're basically, again, backups. Because
19 they're backups there is no automatic actuation of
20 those pumps, it's all depending upon manual operator
21 action from the control room to basically start the
22 pumps and align them to the steam generators.
23 MEMBER SIEBER: You're preferred aux
24 feedwater is still 200 gpm per steam generator?
25 MR. DUNNE: Yes. Yes.

1 MEMBER SIEBER: But you sacrifice margin?

2 MR. DUNNE: Yes, we have. For example, we

3 don't --

4 MEMBER SIEBER: How much margin do you

5 have left?

6 MR. DUNNE: Well, what happens is at the

7 existing power level we don't need 200 gpm. We need

8 around 170 gpm. And so for uprate the analysis -- I

9 believe the last analysis showed we needed 195 gpm.

10 So it's still within the capability of our 200 gpm

11 system. Obviously there's less margin, again with an

12 increase in decay heat you're going to get less

13 margin. Just a fact of life.

14 Now our standby aux feedwater system, it's

15 also a 200 gpm system, however because it requires

16 manual operator action, it does not get an automatic

17 actuation signal, so if you bring it into a high

18 energy line break concern later in time than you would

19 the preferred system. And basically at the uprated

20 conditions the 200 gpm flow capability we presently

21 have was not sufficient to meet the acceptance

22 criteria for the analysis. The analysis Westinghouse

23 did at uprate said we needed 235 gpm delivery

24 capability to the generator for a feedwater line

25 break, which they analysis as a loss of feedwater

1 event.

2 MEMBER SIEBER: But the standby system is

3 there for Appendix R, I take it, and --

4 MR. DUNNE: It's high energy line break

5 and Appendix R, yes. And for --

6 MEMBER SIEBER: But it's manual, you can't

7 take credit for it?

8 MR. DUNNE: We can take credit for it for

9 the high energy line breaks that it was put into to

10 mitigate.

11 MEMBER SIEBER: Right.

12 MR. DUNNE: Basically --

13 MEMBER SIEBER: You don't have a lot of

14 margin?

15 MR. DUNNE: So we need to increase the

16 flow capability. The pumps are actually 600 gpm pumps.

17 So the pumps themselves are not an issue. So what we

18 ended up doing and to get 235 gpm, we basically have

19 to decrease the hydraulic resistance in the flow path

20 which got us into this modification to change out an

21 existing flow control valve on the discharge with a

22 larger valve, basically, so that we can pump 235 gpm

23 into a generator at a code safety valve setpoint,

24 basically.

25 Additionally, like you mentioned, we use

1 our standby aux feedwater pumps for Appendix R
2 scenarios. Ginna has this unique required capability
3 of doing -- going to cold shutdown using the steam
4 generators in a water solid mode where we use standby
5 aux feedwater.
6 MEMBER SIEBER: Right.
7 MR. DUNNE: If you get down to a normal
8 RHR tie in and you don't have RHR and you want to go
9 to cold shutdown, basically what we would end up
10 doing, we would steam the generators down with
11 atmospheric dumps for a period of time and get as low
12 as we could, and then transition to basically water
13 solid steam generator cooling where we start at
14 standby aux feedwater and basically pump water into
15 the steam generators and take water out through the
16 main steam lines to reflect that.
17 Now for that uprate has effected that flow
18 capability. Presently for the present power level we
19 need, I believe, 225 gpm. Going to uprate because of
20 the increase in decay heat, we need to go up to 250
21 gpm.
22 Now from a pump point of view it's not
23 really an issue or from a hydraulic resistance point
24 of view because when we do that the steam generator
25 pressures are down around a couple hundred psi so

1 you've got excess head margin on your pump to be able
2 to put that flow into your generators. So it's not
3 really that scenario that's controlling our
4 modification. Our modification is being controlled by
5 our need to be able to put water into the generator
6 for a high energy line break event where the
7 generators are sitting at a code safety valve setpoint
8 of basically 1085.
9 The other systems that are obviously
10 affected by uprate by decay heat removal systems. For
11 Ginna that basically entails three different systems
12 or our residual heat removal system, which basically
13 is the primary path. That rejects heat to our
14 component cooling water system, which is an
15 intermediate loop, and then the component cooling
16 water system in turn rejects heat to our service water
17 system. The service water system uses Lake Ontario as
18 its water source. And it delivers the water back to
19 Lake Ontario, which is our ultimate heat sink.
20 So basically, again, we evaluated the
21 capability of those systems to handle both normal
22 shutdown and accident long term containment cooling
23 with the existing heat removal capability. And in
24 general they can still support both normal shutdown
25 and long term cooling and containment. Obviously, the

1 times required to get to cold shutdown have lengthened
2 out and the times to depressurize the containment have
3 lengthened out because of the increase in decay heat,
4 but we're still able to meet our functional
5 requirements.
6 The last system is spent fuel pool
7 cooling, which is obviously another one affected by
8 decay heat. For spent fuel pool cooling our
9 requirements are for a full core offload, we will not
10 initiate a full core offload until the cooling
11 capability of the system can match the decay heat load
12 in the pool. That's in our technical requirements
13 manual whenever we do a full core offload, we have to
14 do a cycle specific analysis of our cooling
15 capability, which will take into account lake
16 temperature, whether it's summer, spring or fall and--
17 MEMBER WALLIS: Are there any trends in
18 lake temperature with the years? I know there's
19 rather peculiar years recently, but are there other
20 trends with the years that we should need to take into
21 consideration?
22 MR. DUNNE: We don't believe so yet. But--
23 MEMBER WALLIS: Not yet?
24 MR. DUNNE: I mean, we can go back and
25 look at a ten year history and we'll find some years

1 where it gets hotter than others. For example, last
2 summer it was a very hot summer, probably the hottest
3 we've had in the last ten years. But the summer before
4 it was very cool, one of the coolest ones we've had in
5 the last ten years.
6 Now to address that what we did -- what we
7 have done is raised our design basis lake temperature.
8 Not as part of uprate. We did that a couple of years
9 ago. It used to be the design basis lake temperature
10 for Ginna was 80 degrees because historically you very
11 rarely exceeded 80 degrees. But every time during the
12 summer when the lake would start going up to 75, 76,
13 77, everybody would get in a fit about are we going to
14 exceed 80, what are we going to do. And we'd start to
15 put JCOs in place and then the lake would cool off and
16 we'd never use them. But there were about four or five
17 summers where we do that.
18 So about three or four years ago we went
19 through and did a 5059 to increase the design basis
20 the lake temperature from 80 to 85. We don't expect
21 ever to see 85 degrees. We might see 80 on a hot day
22 occasionally. But we will not see 85. At least not
23 while I'm working, anyway.
24 MEMBER SIEBER: What you need is a lake
25 cooling system.

1 MR. DUNNE: Yes. And Lake Ontario has
2 this unique feature of turning over on us every now
3 and then where the lake temperature will go from that
4 75 degrees to like 40 degrees in five or six hours.
5 But we haven't figure out how to predict that.
6 And unless there are any other questions,
7 that's all I have.
8 CHAIRMAN DENNING: Good. Thank you.
9 MR. DUNNE: And I think I turn it over to
10 the NRC.
11 CHAIRMAN DENNING: Do we want to go with
12 a break now?
13 MR. MILANO: We can do it either way.
14 CHAIRMAN DENNING: Let's do that. It's
15 3:22. Fifteen minutes, let's make that 3:40. All
16 right.
17 (Whereupon, at 3:22 p.m. off the record
18 until 30:40 p.m.)
19 CHAIRMAN DENNING: Okay. Next speaker.
20 MR. MIRANDA: Right. The rest of the
21 afternoon is going to be taken up by presentation from
22 the NRR Staff. We're going to start off with our
23 Reactor Vessel Materials Reviewer, Neil Ray, who will
24 provide the reactor vessels and internals review. And
25 following him from that same organization talking

1 about the reactor coolant pressure boundary materials
2 will be Timothy Steingass.
3 Neil?
4 MR. RAY: Good afternoon. By this time you
5 know that I am Neil Ray from NRR, materials engineer.
6 We looked into the effects of this EPU on
7 reactor vessels materials properties and its impacts
8 and also on the reactor internal and core support
9 materials.
10 Now, reactor vessel integrity when we call
11 it integrity, we looked into surveillance capsule
12 program. Because of the EPU there will be the
13 possibility of reactor vessel clearance, and that may
14 impact surveillance capsule program, so we looked into
15 it.
16 We also looked at additional effect on the
17 reactor vessel integrity. And as I said, we looked
18 into the reactor vessel internals and core support
19 materials.
20 Regarding surveillance capsule program,
21 because the EPU fluence is greater than 200°F, that's
22 not a surprise it was there before. And as part of
23 ASME standard still they have to have 5 capsule
24 withdrawal. Four capsules already withdrawn from that
25 Ginna vessel, and fifth capsule is planned for

1 withdrawal at 5.45 E19, which is the EOL. When I say
2 EOL, keep in mind that is extended life not our
3 intended of life. SO EOL is 5.45 E19. So that
4 basically says between one to two times the peak EOL
5 fluence, which is perfectly all right for ASME
6 standard.
7 MEMBER WALLIS: So it meets the boundary
8 by less than one percent accuracy.
9 MR. RAY: That's is correct. That is
10 correct.
11 MEMBER WALLIS: Which is probably not as
12 accurate as you know the fluence anyway. It's the
13 same as we had before, isn't it?
14 MR. RAY: Yes. Okay. So there is no
15 basically on surveillance capsule program. Just to
16 tell you for that, they are planning to --
17 MEMBER WALLIS: Well, suppose that it was
18 not just over the limit, would they then withdraw it
19 at a different time or something?
20 MR. RAY: Yes.
21 MR. WROBEL: Yes. Can I answer that?
22 George Wrobel from Ginna.
23 Yes. Right now I think you were going to
24 say we're going to withdraw in 2006. We refined our
25 calculations a little bit and we're going to wait

1 until 2008 to make sure --

2 MEMBER WALLIS: So you have plenty of

3 flexibility there?

4 MR. WROBEL: Excuse me?

5 MEMBER WALLIS: You have plenty of

6 flexibility.

7 MR. WROBEL: We have plenty of flexibility

8 in that withdrawal.

9 MR. RAY: Yes, they do. Actually, in a

10 sense, just off the record the letter that we have

11 done is better for them also. Because you are talking

12 about 60 years. And they have the last capsule

13 they're planning with withdraw when it's predicted to

14 be accumulated 80 years. That is the capsule end, I

15 suppose.

16 Okay. That's all about surveillance

17 capsule. Let's move into the other area that the

18 radiation embrittlement may impact, that is the

19 pressure temperature limits, upper shelf energy,

20 pressurized thermal shock.

21 Now pressure temperature limits is a

22 fairly straightforward. What happened is their current

23 limits is applicable up to 28 EFPY. And that is based

24 on the cumulate fluence of 3.11 E19 and the

25 corresponding adjusted reference temperature they

1 calculated. Now because of the EPU and the new
2 calculation methodology and in the meantime the
3 fluence design differences, their cumulative fluence
4 with EPU is reduced, which is 2.01 E19 n/cm^2 (E>1.0
5 MeV). So obviously every other parameters in
6 developing pressure temperature limits remaining
7 constant so their current pressure temperature limit
8 is bounding, and so there is no impact whatsoever in
9 terms of pressure limits.
10 Is there any question on that?
11 MEMBER WALLIS: So the fluence of the EPU
12 is less than --
13 MR. RAY: Yes, I know somebody will ask
14 that question.
15 MEMBER WALLIS: Is this because they've
16 used a different method or something?
17 MR. RAY: Well, there are two
18 possibilities. One is you have to keep in mind this
19 pressure limit they've allowed several years ago. At
20 that time from that point onwards they probably have
21 low leakage goal,number one.
22 Number two, they have a different
23 procedure in calculation. They've withdrawn the
24 capsule so the dosimeter, everything put together they
25 are ready for -- it kind of surprises most of the

1 people, but it does happen all the time.

2 MR. WROBEL: Again, George Wrobel from

3 Ginna.

4 We did use the Reg. Guide 1.190

5 methodology which is more accurate we think.

6 MR. RAY: Yes.

7 MR. WROBEL: But you know the original

8 methodology was a lot more conservative than that. So

9 it looks like we have a lot margin that we gained.

10 MR. RAY: Yes. Okay. So that's what I

11 did, don't have to do anything with the PT limits. It

12 will be applicable up to 28 year EFPY and prior to

13 that, they have to generate new PT limits, which will

14 be applicable probably up to 54 year period or so.

15 MR. WROBEL: Yes. We've currently done

16 the analysis out to 32 already. We haven't submitted

17 that, but that's been completed.

18 MR. RAY: Okay. Now regarding upper shelf

19 energy, except two particular waves -- waves are

20 always a problem, as we all know, for upper shelf

21 energy and PT issues. And in this case they have

22 intermediate-to-lower shell girth weld and the

23 intermediate-to-nozzle shell. Both of them dropped

24 below 54 pounds based on Reg. Guide. So as you all

25 know that there is a ASME Code, Section XL Appendix K

1 calculation that always gives you green signal and you
2 move ahead. That's exactly what they did and that's
3 perfectly all right. So there is no upper shelf
4 energy problem. That's in a nutshell. And we verified
5 their calculation as well.
6 Pressurized thermal shock. Well, again,
7 because of the increasing fluence there end of life,
8 again 54 or up to extended life, was 270.6. Now it
9 increased to 273 using the EPU fluence which is no
10 nevermind, because our screening criteria all software
11 needs 300. So they have enough margin there.
12 So PTS is also not a problem.
13 Now regarding the reactor internal and
14 core support materials, currently they are following
15 ASME Section XI inservice inspection program with PT1
16 and PT3 procedures. And they committed that they will
17 participate and follow whatever comes out of the EPRI
18 MRP program, which we are all anxiously waiting for at
19 this moment. We don't know what will come out. But
20 they committed, they will follow through and they will
21 let us know. And that perfectly fulfills our Review
22 Standard RS-001.
23 So in conclusion we looked into the areas
24 that the reactor vessels and internals and it looks,
25 all of them, pretty good in a satisfactory margin.

1 There is no significant that concern us that we can
2 think of. So I think they're in good shape.
3 Any questions, any part of that
4 discussion? Thanks.
5 CHAIRMAN DENNING: Thank you.
6 MR. MIRANDA: Tim?
7 MR. STEINGASS: Good afternoon. My name is
8 T.K. Steingass. I was introduce as Timothy, and I
9 haven't been called that in about 30 years.
10 I'm a material engineer in the Flaw
11 Evaluation and Welding Branch.
12 I want to talk about the reactor coolant
13 pressure boundary, how the EPU effects or I evaluated
14 how or what effect the EPU may have on the reactor
15 coolant pressure boundary.
16 The review covered the specification
17 compatibility of the reactor coolant, fabrication and
18 processing, material susceptibility to degradation,
19 the degradation management programs that were in
20 effect -- that will be in effect, EPU impact on
21 failure mechanisms and leak before break analyses.
22 The degradation mechanisms that I looked
23 at were under austenitic stainless steels and the
24 reactor coolant pressure boundary, what impact EPU may
25 have on the acceleration or impact on IGSCC. Of

1 course, we're concerned with the sensitized
2 microstructure and the effect of the EPU on the hot
3 leg is only 8.6°F.
4 Transgranular and stress corrosion
5 cracking, through the introduction of halogens that
6 may aggravate that failure mechanism. So, as I said
7 before, the 8.6 degree increase and the slightly
8 elevated chemistry of 3.5 ppm lithium is still within
9 EPRI guidelines. Therefore, those two failure
10 mechanisms are not accelerated or aggravated through
11 the EPU.
12 For alloy 600 and 82 and 182 welds, what
13 the major concern is PWSCC as we've seen in the Davis-
14 Besse head. For Ginna the reactor head was replaced
15 in 2003 with alloy 690 material which will probably
16 start cracking further on down the line than the first
17 one did.
18 Other susceptible program or other
19 susceptible components like the thimble tubes, welds
20 in the bottom head, they're still going to be
21 susceptible to PWSCC, of course. But again, the EPU
22 does not introduce any new failure mechanisms or
23 accelerate that. So consequently there's still going
24 to be cracking, but under the license renewal
25 application process I looked at whether or not there

1 were existing programs that would manage or aging
2 management programs to assure that these components
3 will still remain operable and perform their design
4 function.
5 These programs were approved by the staff,
6 these aging management programs, under NUREG-1786.
7 Consequently, I came to the conclusion that the
8 effects of PWSCC will be adequately managed.
9 MEMBER SIEBER: Now when you talk about
10 increase in temperature is 8.6 degrees in the hot leg.
11 MR. STEINGASS: Yes, sir.
12 MEMBER SIEBER: That's an increase in the
13 nominal temperature based on what their operating
14 parameters are now planned to be as opposed to the
15 maximum that they could be allowed, I take it?
16 MR. STEINGASS: That's correct.
17 MEMBER SIEBER: On the other hand, there's
18 nothing that would prevent the operators of the plant
19 from moving to a higher hot leg temperature and still
20 be within the bounds of the approved EPU?
21 MR. STEINGASS: Due to a power excursion
22 or just --
23 MEMBER SIEBER: No. I mean as a regular
24 way of operation, day-to-day operation. Because you
25 know they've been given a range of values where they

1 can operate and they have chosen ones that give them
2 a T_{Hot} temperature of 609, but they could go as high
3 as, what, 617?
4 MR. DUNNE: This is Jim Dunne.
5 During a cycle that won't happen. I mean,
6 we have a --
7 MEMBER SIEBER: Well, that's because you
8 chose to operate --
9 MR. DUNNE: Yes.
10 MEMBER SIEBER: -- where you're at.
11 MR. DUNNE: Yes. They can --
12 MEMBER SIEBER: But there's nothing in our
13 rules that would prevent you from increasing that.
14 MR. DUNNE: We could increase up to the
15 576 number with a value with a nominal dead band
16 around that, which is nominally I believe 2 degrees.
17 But we wouldn't be able to go in and say we're going
18 to start operating the plant at 578 normally, because
19 that would be outside the span that we've done the
20 analysis for. We'd have to reanalyze the plant for
21 going to a Tavg temperature greater than 576.
22 MEMBER SIEBER: Okay. I'll have to think
23 about that for a little bit. But it just seems to me
24 that you could change Tavg and your ultimate T_{Hot}
25 without additional interaction with the Staff. And if

1 you had 82, 182 weld buttering someplace that could
2 accelerate, it's aging.
3 MR. WILSON: This is David Wilson, Ginna.
4 If we made changes like that, our
5 commitments under license renewal requires us to
6 reevaluate the programs also and evaluate whether or
7 not the conclusions of the Staff agreed to our
8 extended operating license were still valid. And
9 perhaps even have to go back and get approval to do it
10 because of the license renewal programs.
11 MEMBER SIEBER: Okay. Well, like I said
12 before, that's something that I would have to check
13 on.
14 Does the Staff agree that they would have
15 to come back?
16 MR. WILSON: Well we'd start under the
17 5059 process, of course.
18 MR. MIRANDA: That's what I was going to
19 say. Even though they had some margin in the band of
20 what they could operate to --
21 MEMBER SIEBER: Right.
22 MR. MIRANDA: -- if they did decide to it,
23 that their 5059 process drives them to have to
24 evaluate it, the license renewal commitments are part
25 of the licensing basis of the plant and that would

1 dictate, you know, whether or not there's a need for
2 prior NRC approval.
3 MEMBER SIEBER: Okay. Under my postulate
4 circumstances, would they be required to come back?
5 MR. MIRANDA: I couldn't answer that right
6 now.
7 MEMBER SIEBER: Okay.
8 MR. STEINGASS: Another thing I looked at
9 was the leak before break analyses. Does what these
10 people do and what these people pretend to do have any
11 impact on the existing leak before break analyses.
12 So I looked to determine if the analyses
13 were impacted by the EPU under WCAP-15837. The leak
14 before break analysis of the primary loop piping and
15 reactor coolant pump casing was performed in 2002 for
16 Ginna under their license renewal application. The
17 people at Ginna evaluated the impact of the EPU on the
18 conclusions reached in their 2002 leak before break
19 analysis, which was approved by the Staff in NUREG-
20 1786.
21 The review summary 001 lists under SRP
22 Section 3.6.3 the following acceptance criteria for a
23 leak for break analysis. A margin of 10 on leak rate;
24 a margin of 2 on critical flaw size, and; a margin of
25 1 of loads.

1 The evaluation done by the licensee showed
2 that they met the acceptance criteria. For EPU they
3 had a margin of ten, on critical flaw size a margin of
4 2 and a margin of 1 for loads.
5 Consequentially, I came to the following
6 conclusion. The licensee has adequately evaluated the
7 effects of EPU or reactor coolant boundary materials.
8 No new failure mechanisms have been incorporated due
9 to the EPU.
10 The licensee has appropriately identified
11 aging management programs to address effects of
12 changes in system operating temperatures. And this was
13 done on a license renewal application process.
14 The licensee has demonstrated that a leak
15 before break analysis remained valid under EPU
16 conditions. Consequently per the review summary 001
17 Matrix 1 design criteria 1.-4,-14, -31, 10 CFR 50
18 Appendix G and 10 CRF 50.55(a) requirements have been
19 met. And that's all I have.
20 MR. MIRANDA: All right thank you.
21 MR. STEINGASS: You're welcome.
22 MR. MIRANDA: Okay. Continuing on to the
23 next area is Kamel Manoly. He's the Chief of the
24 Mechanical Engineering Branch.
25 MR. MANOLY: Good afternoon. I'm Kamel

1 Manoly, Chief of the Engineering Mechanics Branch in
2 Division of Engineering.
3 And we have Dr. John Wu, the leader
4 reviewer for the power uprate.
5 Okay. The first slide basically shows the
6 components that were evaluated in the Ginna power
7 uprate. Typically it would be the vessel and
8 internals and the nozzle and supports.
9 Like to note that the vessel was designed
10 to ASME 1965 edition and the NSSS was designed to the
11 ANSI 1967 with '73 addenda. So the NSSS did not have
12 the traditional fatigue analysis as the more recent
13 plants do.
14 We also looked at the replacement steam
15 generators and the reactor coolant pump, pressurizer
16 and supports and vessel BOP piping system and supports
17 and also the components, valves, MOVs, AOVs and SRVs.
18 We typically evaluate the methodology and
19 the loads applied, and calculated the stresses and
20 usage factors. The primarily one would be for the
21 vessel because explicit fatigue analysis whereas for
22 the other components the NSSS of you use then ANSI
23 1967 then the '73, it doesn't have explicit cumulative
24 uses factor like Class 1 components.
25 We also looked at the functionality and

1 impact of EPU on the three major GL 89-10 and 95-07.
2 And I believe also we looked at on GL 96-06, I
3 believe.
4 And we also looked if there's any conflict
5 between the EPU and the license renewal and the
6 evaluations covers the 60 year span.
7 And finally then NSSS and BOP piping
8 systems and supports.
9 I'd like to note that Ginna's approved for
10 the leak before break criterion, which eliminate pipe
11 breaks ten inches and larger. So the limiting break
12 sizes were obviously in the smaller lines 3 inches and
13 2 inches. A specific evaluation was done for the
14 safety injection line, the hot leg and the 4 inch
15 upper plenum injection line connected to the vessel.
16 The finite element analysis using the
17 ESTDYN code, I believe that's a Westinghouse code, and
18 compared the stresses using the ANSI B31.1 limits and
19 ASME what are applicable.
20 CHAIRMAN DENNING: Could you speak up just
21 a little bit.
22 MR. MANOLY: Okay.
23 CHAIRMAN DENNING: Thanks.
24 MEMBER WALLIS: I'm sorry. These
25 calculated stresses were stresses all calculated by

1 the licensee?

2 MR. MANOLY: Yes.

3 MEMBER WALLIS: What did you do to satisfy

4 yourself that they had done this correctly?

5 MR. MANOLY: We looked at the summary of

6 the analyses. We did not do -- we don't do an

7 additional analysis to verify what they have done. We

8 just look at the results and see if it's reasonable

9 and --

10 MEMBER WALLIS: You look at the basis for

11 the results?

12 MR. MANOLY: Yes. Yes. And, obviously,

13 every power uprate has it's own uniquenesses. And for

14 this power uprate probably the things that comes to

15 mind the most is vibration issues of the components

16 and the steam line. And that's where we did the most

17 focus on areas where we expect, you know, issues can

18 come up.

19 We note that the result of the EPU, the

20 licensee upgraded nine supports and added one support

21 in main steam line. And added also one support in the

22 feedwater line to address the effect of increased

23 flow.

24 I think the first bullet points that we

25 verified that they account for 60 years of operation

1 to show that the fatigue limits does not exceed the
2 value of one.
3 We looked at the effect of flow on
4 vibration on the steam separators because it's
5 expected to increase the EPU. And it was found
6 acceptable. The concerns in the boiling water
7 reactors is very different than for the pressurized
8 reactors. The flow here is pretty much parallel to the
9 primary tubes so you don't get the cross flow that
10 would invite flow induced vibration issues.
11 And also the separators are basically a
12 very rugged which are not going to be amenable to the
13 flow induced vibration as you would expect in the
14 steam dryers and the boilers.
15 CHAIRMAN DENNING: When you said "judge to
16 be acceptable," what quantitative guidelines did you
17 use?
18 MR. MANOLY: Well, we know that that
19 design of a generator has been used before. They did
20 the testing of the new dryer I think the facility in
21 Canada. So they did testing of that dryer itself. And
22 there are several plants that use the same design at
23 a higher velocity coming from the restricting nozzle
24 than from Ginna. And there hasn't been really any
25 issue. So operation really is the best test of a

1 component.

2 CHAIRMAN DENNING: Incidently, that type

3 of insight helps us quite a bit in evaluating

4 statements like this.

5 MR. MANOLY: Yes. I can tell you the steam

6 velocities through the flow restrictors after the EPU

7 are lower than steam velocities at similar plants like

8 Byron, Braidwood, McGuire and Catawba. So there

9 hasn't been any issue there, so I wouldn't expect that

10 to have any issue here.

11 MEMBER WALLIS: So these notes that you're

12 referring to, are they part of the public record or

13 are they your own private notes that --

14 MR. MANOLY: No, this was in application.

15 MEMBER WALLIS: So the numbers you're

16 quoting to us are from their application?

17 MR. MANOLY: You mean the velocities? I

18 didn't really give numbers. I'm just saying the

19 number was lower than.

20 MEMBER WALLIS: Yes, but those numbers

21 you've just given us, is that document you're reading

22 from, is that part of the public record?

23 MR. MANOLY: Yes. This is from the

24 application itself.

25 MEMBER WALLIS: From the application?

1 MR. MANOLY: Yes. Yes.

2 MEMBER WALLIS: So it's not something

3 that. you dug out yourself?

4 MR. MANOLY: No. No. Well, RIAs back and

5 forth. But that's also in the public record.

6 MEMBER WALLIS: Well I just wonder when

7 the Staff has all these judge to be acceptable

8 statement and we don't know why, there is a paper

9 trail somewhere that it could be investigated if

10 necessary.

11 MR. CARUSO: Yes, there is.

12 MEMBER WALLIS: There is.

13 MR. MIRANDA: We have the application, we

14 have all the RAIs.

15 MEMBER WALLIS: And you have all the RAIs?

16 And that includes everything that justifies this

17 "judged to be acceptable" statement?

18 MR. MIRANDA: Everything that's been

19 publicly documented, yes.

20 CHAIRMAN DENNING: But there's no trace

21 line, though, that --

22 MEMBER WALLIS: Is there a trace line of

23 your rationale somewhere?

24 MEMBER SIEBER: No, it doesn't say why.

25 MEMBER WALLIS: It doesn't say why. Then

1 why is the key question, though, isn't it?

2 MEMBER SIEBER: Yes.

3 MR. MANOLY: Sometimes the why is it meets

4 the code limits, sometimes why is -- like here for the

5 monitoring after the operation going to using OM

6 standard. If they meet the OM standard for vibration,

7 that will be the reason.

8 CHAIRMAN DENNING: But if it isn't the

9 SER, then there really isn't a --

10 MR. MANOLY: Oh, no, definitely. I mean

11 we say that -- where it meets certain code limits or,

12 you know, vibration testing limits, those are the

13 basis that constitute acceptance.

14 CHAIRMAN DENNING: Continue. Oh, you

15 mentioned there's a slight increase in flow rate and

16 induced vibration in the U-bend tubing?

17 MR. MANOLY: Yes. Yes. But they evaluated

18 that and found the -- see, the acceptance limit here

19 is the stability ratio is less than one. So if it

20 shows it's less than one, then that will be

21 acceptability. I mean, that is the criterion for

22 acceptance based on analysis that was done.

23 MR. WU: This is John Wu.

24 About flow in this vibration evaluation,

25 normally we looked at the flow induced vibration, you

1 know, the -- what the maximum is and what it's close
2 instabilities is going to have close -- and I don't
3 know why it's look at -- you know, even it's low but
4 sometimes you look at the past experience because it's
5 the operating experience compared to, you know, the
6 seeing the prints and we do that.
7 For this one like the four separator, you
8 look at that-- this can do, I think it's B&W Canada,
9 they were similar plants, about 44 steam generator in
10 Canada, about 34 in United States, it's a similar
11 plant. And there's no failure, no records of any
12 indication at all. So this is very sturdy.
13 And I talk about showing this vibration
14 normally we look at instability like -- instability
15 through such a instability number. And which is normal
16 in their criterion is pretty low, probably -- maybe --
17 you know, normally we look at less than one and that
18 is instability. Less than one where we would consider
19 acceptable. And also you look at -- like vortex
20 shedding and like turbulence goes through. But here
21 because the flow is parallel to the separator so it's
22 minimal. There's no shedding. And even there's
23 shedding, it's very small at all. Very small. Like
24 tubing, tubing has -- so there's more shedding and
25 more shedding. So I think sometimes they have a

1 criteria and something like 15 -- like you know two
2 percent of the allowance, something like that. But the
3 2 percent is based on the fix/fix type of -- fix/fix
4 type.
5 But the idea is try to keep the trace
6 level below the endurance limits so no matter how you
7 shake, it won't break even for --
8 MEMBER WALLIS: So the best argument is
9 that there is a lot of experience with similar steam
10 generators?
11 MR. WU: Yes.
12 MR. MANOLY: Yes. Yes.
13 MEMBER WALLIS: Because the predictability
14 of flow induced vibration from -- is not that good, as
15 we know from some other experiences. There are some
16 vibrations which sometimes occur as a surprise?
17 MEMBER SIEBER: But I think you're right,
18 you can't tell the basis just from reading the SER.
19 MR. MIRANDA: Well, you can't tell the
20 specific basis, I'll agree with you. The fact is that
21 each section of the Staff's evaluation provides a
22 detailed list of the regulatory requirements that the
23 Staff had to assess against along with, you know,
24 whether there were GDCs or whether there were some
25 other type of regulation. And in addition, the Staff

1 reviewed the licensee's application against both the
2 Review Standard itself and that in part called out a
3 lot of the original SRP sections. Albeit it that it
4 may not say it at the end as to what specifically --
5 would it specifically came for a conclusion against
6 each one of the issue. The fact of the matter is is
7 they did review each section against those. And if
8 they didn't, I guess the answer is in the negative.
9 They didn't find anything in those areas so it was
10 acceptable.
11 MEMBER WALLIS: Is there some record, a
12 form of notebooks kept by the Staff member that sort
13 of says that on a certain day I sat down to review
14 this thing and I checked off this, this and this and
15 I was satisfied and after five minutes I went away, or
16 is there something that says I spent three weeks doing
17 it and these are the things I did, and it's all
18 written down somewhere?
19 MR. MIRANDA: No, it is not. That is not
20 part of the --
21 MEMBER WALLIS: So if it were a legal case
22 and somewhere were trying to find out the basis for
23 these decision, how would they be determined?
24 MR. MANOLY: Well, depending on the
25 complexity of the subject. I mean, there are certain

1 areas where we might even do confirmatory analysis and
2 some areas where you have a routine type review, it's
3 not really cost effective to question things that we
4 pretty much know the answers are pretty reasonable.
5 So it depends on -- but the basis always has to be in
6 the SER. Whether it's standards -- meets standard ASME
7 limits, it's in the ASME limits or OM limits. There is
8 always some limit that ultimately we have to point to.
9 MEMBER WALLIS: But what can you do? I
10 mean if the applicant says we calculated 2921 and the
11 ASME limit is 3000, let's say, do you just accept
12 that?
13 MR. MANOLY: Well, this --
14 MEMBER WALLIS: What else can you do?
15 MR. MANOLY: But they describe the
16 analysis. Now when we read the description of what
17 they have done, if it seems reasonable, I'm not going
18 to ask --
19 MEMBER WALLIS: So you look at their
20 notebooks or their calculation sheets or something?
21 MR. MANOLY: No, no, no.
22 MEMBER WALLIS: No?
23 MR. MANOLY: Sometimes we look at the
24 calculation if we suspect something that doesn't seem
25 to add up. But if it seems reasonable --

1 MEMBER WALLIS: Don't you do some random
2 spot checks where you do audits at plants and you say
3 show me your calculation sheet and --
4 MR. MANOLY: No, no. That comes in RAI.
5 I mean, we can ask questions in RAIs that we ask for
6 specific documents that we need to review further. We
7 did not do that in this application because we didn't
8 feel the need to. I mean this --
9 MEMBER WALLIS: So your justification --
10 I mean, we have to rely on your judgment I think in
11 many cases then, don't we?
12 MR. MANOLY: Well, I mean, and I think you
13 learn -- when -- I mean for boiling reactors do you
14 know what have been happening at steam dryers. So
15 when we run into that we do a lot of audits. You
16 know, John just came from an audit of Quad Cities'
17 dryers. He's still -- you know, even though they had
18 the license, but he's still auditing the calculations.
19 We've been doing that for the last, probably year and
20 a half or two because there is a cause for that.
21 And I think the effort, we put the effort
22 where we can get maximum return out of the time we
23 spend.
24 CHAIRMAN DENNING: You may continue.
25 MR. MANOLY: All right. I think John

1 pretty much covered this slide.

2 I think the first bullet basically, the

3 reliance on the first bullet on the load downs that

4 are going to be done prior to the power uprate is the

5 baseline and then get evaluation that weren't

6 continued observation of the steam line where they

7 think that potentially there to be increased

8 vibration.

9 The second bullet basically addresses that

10 the flow is primarily parallel to the axis of the

11 tubes. And the possibility of FIVs is respect to --

12 of vortex shedding is apparently very low.

13 And that pretty much covers this slide.

14 The next one is the specifics about the

15 separators. Inspections on fatigue for flow induced

16 vibration did not reveal any issues in previous

17 separators. We know the design of this one is fairly

18 rugged in the new design, so it minimizes the chances

19 for FIV. And the velocity, as I mentioned, is fairly

20 low. And also the -- they have a flow -- I guess like

21 a nozzle that would capture anything of any size that

22 potentially can break loose before it goes to the

23 turbine.

24 And if anything breaks, it potentially it

25 an get caught at the support plate inside the steam

1 generator. This is just one of the scenarios.

2 But we didn't really feel that there was

3 any concern about the separators in this plant.

4 CHAIRMAN DENNING: Tomorrow we're going to

5 hear about the power ascension testing. Based upon

6 your assessment of potential for vibration do you make

7 recommendations as to what kind of monitoring you

8 think should be done or where monitoring should be

9 done to detect vibrations if they should be

10 encountered as the power level increases?

11 MR. MANOLY: Well, they identified the

12 systems, the lines that they're going to be monitoring

13 in the application. The licensee. And they're going

14 to do baseline walkdown first at 100 percent power,

15 current 100 percent and then they're going to be

16 monitoring certain locations. So we agree with the

17 list with what they identified. They're going to meet

18 OM code, OM3 is very conservative criteria for

19 vibration.

20 CHAIRMAN DENNING: Yes. What about lack of

21 monitoring the steam lines, is that an issue?

22 MR. MANOLY: They are monitoring the steam

23 lines.

24 CHAIRMAN DENNING: What's that?

25 MR. MANOLY: They are monitoring the steam

1 lines, I believe.

2 CHAIRMAN DENNING: Well it's my

3 understanding they weren't, but it might have been a

4 misinterpretation.

5 MR. MANOLY: No. I think the licensee can

6 say. The application says they're going to monitor

7 the steam lines. They're going to determine the

8 portions within the steam lines that they're going to

9 monitor.

10 CHAIRMAN DENNING: Can you respond to that

11 from the plant?

12 MR. DUNNE: This is Jim Dunne.

13 Basically based on the -- we've agreed

14 with the NRC that we should be monitoring certain

15 locations in the plant, probably primarily main

16 feedwater and main steam piping. We're going to use

17 our baseline visual walkdown that we did last week to

18 identify specific locations in both systems that we

19 think we should monitor going forward. We haven't

20 identified those points yet. But the plan is that

21 there will be some monitoring of main steam line and

22 feedwater locations based upon the visual walkdown.

23 MR. MIRANDA: A number of the issues that

24 you're asking about if you look through the history of

25 some of the later requests for additional information

1 you'll see it where we ask questions with regard to
2 the post-EPU conditions, whether they be flow or
3 otherwise in comparison to industry norms and things
4 like that. And in the course of the RAIs and
5 discussions via teleconferences and others, we
6 determined whether or not or we agreed with the fact
7 that their program is focusing towards the right
8 systems and components and stuff.
9 So what you're asking is is we did do it
10 and we did it outside of the initial application
11 review.
12 CHAIRMAN DENNING: Okay.
13 MR. MANOLY: I think this is the last
14 slide. Yes, it's the last slide. Components.
15 Mechanical components.
16 MR. MIRANDA: So that concludes the
17 engineering mechanics portion. If there aren't any
18 other questions, Greg Makar is going to talk about
19 flow accelerated corrosion and some other --
20 MR. MAKER: Thank you.
21 Yes. I'm going to talk about five systems.
22 I'm going to talk about flow accelerate corrosion,
23 steam generator tube integrity, the steam generator
24 blow down system, the chemical and volume control
25 system and finally paint and other organic materials.

1 And I'd like to start with flow
2 accelerated corrosion or FAC. FAC is a corrosion
3 thinning mechanism that, as you heard from Jim Dunne,
4 it involves an interaction between several variables,
5 including the temperature, flow rate, the moisture
6 content and the alloy of the components. So what's
7 going on in the pipe and what the pipe is made of.
8 And we focused our evaluation on where
9 there are changes. Because some components will
10 experience changes in some of these parameters.
11 MR. MIRANDA: You want to go up one slide.
12 MR. MAKER: Thank you.
13 What we look for is scoping first of all,
14 that the license was looking at the changes due to the
15 EPU and seeing what effect that would have on
16 components and whether they needed to add components
17 into their FAC program.
18 And they did. They evaluated those
19 parameters, temperature, etc. And they found, for
20 example, cases of inlet nozzles in the feedwater
21 systems where they had high flow rates and now they
22 were increasing the temperature from below the
23 threshold of about 212°F to above that threshold. And
24 those things were added into the program.
25 So after the scoping, the CHECWORKS, the

1 EPRI CHECWORKS program is one of the tools that they
2 used to monitor FAC and manage FAC. This program
3 allows for -- since it models system, it allows for
4 changes and they are updating these models for the
5 uprate conditions and provided us with -- well, you
6 saw a table of increases in corrosion rates and
7 thicknesses of pipes due to the EPU. And we saw
8 changes in the corrosion rates. They increased from
9 about 3 percent to 24 percent. And the actual
10 corrosion rates themselves up to about five mils per
11 year.
12 And this group of components that they
13 evaluated and showed us the evaluations for covered a
14 variety of component types and sizes and operating
15 conditions.
16 So this was our basis for concluding that
17 at EPU conditions their program will continue to
18 manage FAC. The scoping, the fact that they used
19 CHECWORKS and the result that they showed us.
20 And next I'll talk about steam generator
21 tube integrity. The Ginna plant has replacement steam
22 generators, replaced in 1996 with steam generators
23 with alloy 690 thermally treated material. They also
24 have stainless steel tube support materials.
25 In addition to these material changes,

1 there are also some design changes. For example the
2 support structures for the tubing to minimize
3 vibrations and also thermal treatment and design
4 features to reduce stressed in the U-bends relative to
5 other older steam generator designs.
6 The operating parameters, of course will
7 change for the tubing. For example, the after
8 temperature inside will be hotter. But even at the
9 increased T_{Hot} this will still be within the range of
10 other steam generators already operating in the fleet.
11 There are others with higher temperatures that have
12 been operating longer. And for this reason, although
13 the higher temperature will increase the rate of
14 degradation mechanisms, we don't feel it will be
15 significant and it will be managed by their program.
16 The vibrations and wear of the tubes,
17 you've heard that this has been evaluated and there is
18 not an expectation of a lot of tube wear, but tube
19 wear is part of the steam generator tube integrity
20 program it includes degradation assessments that
21 include wear and evaluations of wear if they're found.
22 And so based on the main guidelines we
23 use, which are the NEI 97-06 and the associated EPRI
24 evaluation guidelines, we judge that their inspection
25 program will continue to manage the integrity of the

1 tubes.

2 The steam general blowdown system supports
3 tube integrity by removing impurities from the
4 secondary coolant. And at EPU conditions there will
5 be increases in flow rate of the system. This is going
6 to increase from about 40 to 80 gallons per minute to
7 40 to 100 gallons per minute. This is below design
8 limits and it's also equivalent to what they operated
9 with until about 1990. The temperature and pressure
10 are also increasing, but remaining within the design
11 limits. This is true for the piping and the
12 containment isolation valves.

13 And we also note that this system steam
14 generator blowdown system is monitored within the FAC
15 program. And so we concluded that the power uprate
16 would not effect the ability to remove impurities from
17 the secondary system.

18 On the Chemical and volume control system
19 there's several functions related to water inventory
20 and water quality. The license told us about there is
21 an expectation that there will be need for increase
22 boration and also there is a possibility of increased
23 crud buildup. These increases are within the design
24 limits. The increases in temperature in the system
25 are small and will not effect the operation of the

1 heat exchanges, so therefore not the system in
2 general. And so based on these small changes and all
3 remaining within design, we just that acceptable.
4 Finally, paints and other organic
5 materials. The plant was constructed prior to
6 Regulatory Guide 1.54, which is our guidance now for
7 the application of coatings. The coatings were
8 applied according to Westinghouse and plant
9 specifications. And since then the coating program
10 has also been evaluated under the Generic Letter and
11 license renewal processes. So we are focusing on
12 changes in the coatings from the power uprate.
13 The license provided some temperature
14 containment with pH, spray pH values and radiation
15 dose values and compared that to the values at which
16 those coating were qualified. And so those will all
17 remain within the qualification parameters for normal
18 operation design basis accidents and post-accident
19 operations.
20 So on that basis we don't expect any
21 effect on the adhesion or degradation of the coatings.
22 Not that there isn't degradation, but the effect of
23 the degradation on the plant and other debris is being
24 evaluated under the Generic Letter 2004-02 process.
25 And that includes the effect of power uprate.

1 Now there other organic materials in
2 containment such as --
3 MEMBER WALLIS: Did anyone inspect the
4 coatings at the plant?
5 MR. MAKER: Yes. There are coatings.
6 There's a program for coatings.
7 MEMBER WALLIS: Are they in good shape?
8 Are they all in good shape?
9 CHAIRMAN DENNING: Do you mean as part of
10 power uprate and are you both in agreement here?
11 MEMBER SIEBER: No.
12 MEMBER WALLIS: Well, I think there was a
13 license renewal that probably inspected the coatings.
14 I was wondering what -- I mean, there's a statement
15 that coatings do not detach from the substrate during
16 a design basis LOCA. And I just wondered if their
17 present state when you look at them indicates that
18 they look like the kind of coatings that wouldn't
19 detach. It's a very superficial inspection, but at
20 least --
21 MR. WROBEL: George Wrobel from Ginna.
22 Yes, well we started as a result of
23 Generic Letter 98-05 response, we did a pretty
24 thorough walkdown of containment. And we did another
25 one for IEEE for looking at the protective coatings on

1 the liner. And then every year when we do our
2 containment cleanliness walkdown we do an inspection
3 of the coatings.
4 There is some coatings that are not there.
5 I mean, you know some of the floor there's wear marks
6 and things like that, but we haven't noticed any large
7 layers of coatings being removed. And we did do an
8 assessment of the adhesion of the coatings and there's
9 not any large amounts of coatings that are coming off.
10 There are coatings that are off --
11 MEMBER WALLIS: Because coming off in a
12 design basis LOCA is rather different. They're being
13 bombarded --
14 MR. WROBEL: We didn't do it during a
15 design basis LOCA, I'll give you that.
16 MEMBER WALLIS: So I just wonder what the
17 basis was for asserting that they do not detach from
18 the substrate during a design basis LOCA. Because we
19 know that in some plants that they're bad enough that
20 you may even see some of them detach without any LOCA
21 at all.
22 MR. WROBEL: That's based on the
23 qualification, the original qualification testing.
24 MEMBER WALLIS: The qualitification says
25 they won't happen, that's right.

1 MR. WROBEL: And we have assessed the
2 current coatings against the original coatings that
3 were applied --
4 MEMBER WALLIS: Well, there's no
5 instruction technique which sort of --
6 MR. WROBEL: Not during a LOCA, no.
7 MEMBER WALLIS: -- tests how well they're
8 adhered now. No.
9 MEMBER MAYNARD: Have you ever done any
10 pull test on it or anything? There are tests you can
11 do for coatings to basically glue and see how much--
12 MR. WROBEL: We haven't done comprehensive
13 pull tests, but we have walked down coatings and you
14 can kind of tell if things are adhering. In fact, a
15 few years ago we did do scrapings of the coatings to
16 try to get them off because we want to assess them
17 against -- you know, make sure they were still
18 consistent with the original coating composition. And
19 we actually had a lot of trouble getting coatings off
20 most areas of the plant. Now, again, there were a few
21 areas that was gone already, so we didn't get any
22 coatings.
23 MEMBER MAYNARD: Yes. There are some
24 things you can do besides just looking at that.
25 MR. WROBEL: Yes.

1 MEMBER MAYNARD: And it sounds like you
2 have done some of those.
3 MR. WROBEL: A little bit. It's not a huge
4 comprehensive program yet, but I think this 2004-02 is
5 going to be bringing more.
6 MR. MAKER: Well, I'll finish up with the
7 other organic materials, things like cable insulation
8 that could generate hydrogen and other inorganic acids
9 because of higher temperatures and radiation dose.
10 And the increases will be insignificant. There won't
11 be significant gas generation.
12 CHAIRMAN DENNING: Thank you.
13 MR. MAKER: Okay. You're welcome.
14 MR. MIRANDA: I'd like to introduce Raul
15 Hernandez. He's from our Balance of Plant Branch. And
16 he's going to be talking more in the systems area and
17 the EPU effects and our evaluation of the EPU effect
18 or EPU conditions on a number of the balance of plant
19 systems.
20 MR. HERNANDEZ: My name is Raul Hernandez,
21 like he said. And I'll be discussing the review of
22 the balance of plant section.
23 Our review is based on Review Standard 001
24 Matrix 5. There's over 20 systems in Matrix 5. These
25 systems can be summarized as internal hazards, fission

1 product control, component cooling and decay heat
2 removal, balance of plant system, waste management
3 system, emergency diesel fuel oil storage and light
4 loads. And also we review test consideration for
5 certain balance of plant systems.
6 For the purpose of this presentation we
7 are going to emphasize the spent fuel pool cooling,
8 the service water system and the ultimate heat sink,
9 the auxiliary feedwater system, the condensate and
10 feedwater system. But you can ask questions of any
11 system if you have them.
12 For the spent fuel pool system, the
13 licensee performed a heat load analysis and determined
14 that the heat load would not be exceeded for the spent
15 fuel pool cooling system. And they will maintain
16 administrative control to make sure of this. They will
17 be delaying the full core upload until they have
18 assurance that they have enough cooling capability.
19 The licensee has commit to make some
20 material changes to the tech spec to reflect this new
21 thermal analysis that they have performed.
22 During the evaluation --
23 MEMBER WALLIS: What is this alternate
24 source?
25 MR. HERNANDEZ: What?

1 MEMBER WALLIS: What is the alternate
2 source in the second bullet?
3 MR. HERNANDEZ: Yes. This is for the
4 worst case scenario boil up rate. The licensee has a
5 make up source with -- that is going to be higher that
6 this worst case boil up rate. They have in addition to
7 that an alternate make up water source for the spent
8 fuel pool which has the capability of 50 gallons per
9 minute. This is slightly below the worst case boil up
10 rate of 52.8 gallons per minute. The licensee has
11 done an evaluation and have determined that in the
12 time that it would take for the boil up rate to drop
13 to 50 or below gallons per minute, the spent fuel pool
14 would have lost less than or almost 2 inches of water.
15 The staff determined that based on all the
16 conservatism in the calculations, that this was
17 acceptable. And the licensee has committed to update
18 the USR to include this justification.
19 MEMBER WALLIS: This alternate source is
20 something that's installed and comes on automatically
21 with some signal or something?
22 MR. HERNANDEZ: Well, for the worst case
23 this is if they lose all cooling for the spent fuel
24 pool, they have the capability of providing makeup
25 water for the spent fuel pool from the condensate

1 storage -- excuse me. Let me just make sure.

2 MEMBER WALLIS: So it requires some

3 operator action? It requires some operator action?

4 MR. HERNANDEZ: Yes. Yes. It will take

5 some operator action. It's not an automatic system.

6 The preferred one is the RWST --

7 MEMBER WALLIS: But the operator action is

8 opening valve, it's not laying a line or something?

9 It's not actually installing a hose or something? The

10 hose is already there. It's just opening an valve?

11 MR. MIRANDA: A valve line.

12 MEMBER WALLIS: Right.

13 MR. HERNANDEZ: The alternate source is

14 the CBCS.

15 MR. DUNNE: Yes. The alternate source is

16 our charging system. The other thing is the boiler

17 over which you're going to lose this 2 inches, it's on

18 the order of 19 hours. So that's more -- well before

19 that time we'd have alternate source water available.

20 MEMBER WALLIS: This isn't really an EPU

21 issue anyway, is it?

22 MR. DUNNE: It basically changed because

23 we did an more conservative analysis for EPU than we

24 have presently. And the two inch number we gave the

25 NRC was also a conservative analysis. We basically

1 assumed that we instantaneously offload the entire
2 core at the minimum time, that we instantaneously heat
3 the pool to its limit at that point in time and then
4 we instantaneously lose decay heat, and then we got a
5 boil off. And so there's conservatism in the analysis.
6 MR. HERNANDEZ: Next we're going to be
7 discussing the service water system and the alternate
8 heat sink. For Ginna Lake Ontario is the alternate
9 heat sink.
10 The service water system evaluation has
11 determined that the system has enough capability to
12 handle the decay heat at EPU conditions. Flow rates
13 are capable to handle EPU during the safe shutdown and
14 injection phase only one service water pump is
15 required. But like for, like as I mention here, post-
16 LOCA mitigation recirculation phase, two service water
17 are required. The licensee has committed to revise the
18 tech specs to include this into the tech specs.
19 And like I already mentioned, no
20 modifications are required due to the EPU.
21 For the aux feedwater systems there's some
22 -- over here that you see that the preferred flow --
23 that the preferred AFW required flow has increased 5
24 gallons per minute. There was some confusion in some
25 statement on the application. We discussed this with

1 the licensee and what they discussed before, that the
2 required flow hasn't change, that is acceptable and
3 that was their original intent.
4 CHAIRMAN DENNING: We talked before the
5 break and since then I've had an epiphany and
6 remembered where the numbers came from.
7 Basically Westinghouse for exit analysis
8 basically asked for a minimum AFW flow rate and a
9 maximum AFW flow rate to use. And for whichever
10 analysis if it's conservative to use the minimum, they
11 used the used the maximum if it's conservative to use
12 the maximum, they used the maximum.
13 So right now the way AFW system is
14 designed when it gets automatically initiated is a
15 control valve that throttles back and will stop
16 throttling once the AFW flow gets between a range of
17 200 to 230 gpm.
18 So previously we had always used 200 gpm
19 as our minimum number and 230 gpm as the maximum.
20 For EPU, again this is one of those areas
21 where our instrumentation people would like to have
22 more margin for uncertainty analysis, we decided that
23 we would increase the maximum number from 230 to 235.
24 So for any analysis that Westinghouse did where they
25 need to maximize AFW flow to a steam generation for a

1 particular transient, they are now using a max flow of
2 235 gpm for any analysis. Where it's conservative to
3 use minimum numbers, they're using the existing,
4 they're using the 200 gpm number, which is the
5 capability of the system.
6 So the reality is the way the table is in
7 the submittal it's somewhat confusing to interpret and
8 it does mean you need to increase AFW flow to 230 to
9 235 or a 5 gpm increase. We basically are saying that
10 we are using a conservative up or down for max flow of
11 235 gpm in lieu of 230 gpm for the present licensing
12 basis. So we've added some conservatism to our
13 analysis of record.
14 MR. HERNANDEZ: For the standby AFW
15 systems, the licensee has acknowledged that the
16 required flow has increased. It's supposed to reach 35
17 gallons per minute.
18 The Staff finds this acceptable based on
19 the testing that is going to be performed on the
20 system. Part of the power uprate testing, they're
21 going to perform a test to verify that the system can
22 provide the required flow as it's supposed to.
23 For the condensate and feedwater system
24 the Staff have determined that no safety challenges
25 have been created. There are some major modifications

1 to the system which includes a feedwater regulatory
2 valve, feedwater pumps and the condensate booster
3 pumps.
4 To decrease the severity of certain vents
5 the licensee is performing some system tuning. The
6 ones that we mention here is main feedwater pumps,
7 suction pressure setpoint, main feedwater pump, NPSH
8 calculator setpoint and delays have been added to the
9 low pressure heater bypass value open circuit.
10 Basically this modifications add to reduce the
11 severity of a loss of condensate pump, loss of
12 condensate booster pumps or heat or drain pump.
13 During power accession and during some
14 limited transient, the licensee is going to monitoring
15 the performance of the main feed system to verify
16 their modeling of different areas and to verify the
17 setpoints that they have used.
18 As a summary, the Balance of Plant Staff
19 has determined that the EPU is acceptable with respect
20 with the Balance of Plant area. This is based on the
21 evaluations of the licensee's submittal and their
22 results, the commitments that the licensee has agreed
23 on and the results from the power ascension and
24 transient testing program.
25 Any question?

1 MEMBER SIEBER: Thank you.

2 CHAIRMAN DENNING: Thank you very much.

3 Okay. Let's talk just a little bit about

4 tomorrow, because I think we're done for the day,

5 right?

6 MR. MIRANDA: Right. We are done for

7 today.

8 CHAIRMAN DENNING: As far as tomorrow is

9 concerned, my guess is that we probably will be

10 finishing up an hour before the scheduled time, but

11 it's a little bit hard to interpret now. With regards

12 to what kinds of surprises we might have for you

13 tomorrow and who you ought to have around, I think we

14 ought to talk about that just a little bit.

15 It's conceivable that over the night we

16 might decide we want to talk a little bit more about

17 safety analysis. Do you think that's likely, Graham?

18 I don't know. I don't know whether you're wondering

19 what people should I have here tomorrow and is there

20 anybody that you'd like to dismiss and send home and

21 we could discuss now whether we think that we might

22 miss them.

23 I mean, it's up to you. I don't know

24 whether -- as far as you're concerned, I mean there's

25 a lot of money involved in this whole thing and you

1 might want to just keep them here just in case. But my
2 guess is there's some set of your staff that could
3 really go home, but I don't how to advise you.
4 MR. FINLEY: Right. And we'll be prepared
5 to discuss further safety analysis questions if you
6 have those. As far as our electrical folks and
7 materials, we intended to send them home tonight.
8 CHAIRMAN DENNING: I see absolutely no
9 problem with that.
10 MR. FINLEY: Okay. Then we're fine I
11 think.
12 CHAIRMAN DENNING: Okay. You're fine?
13 Okay. Very good.
14 Then did you have any other comments or
15 questions?
16 MR. MIRANDA: No, I don't.
17 CHAIRMAN DENNING: No? Okay.
18 MR. MIRANDA: So similarly, you would like
19 to have our Staff, our safety analysis staff here
20 also?
21 CHAIRMAN DENNING: I think that would be
22 a good idea. Because --
23 MR. MIRANDA: Just the reactor systems
24 portion or the dose consequences people? Just the
25 reason systems?

1 CHAIRMAN DENNING: Just the reactor
2 systems people.
3 MR. MIRANDA: Okay.
4 CHAIRMAN DENNING: I think we're pretty
5 comfortable with the dose.
6 MR. MIRANDA: Yes, dose came out pretty
7 good.
8 MEMBER WALLIS: Your people in response to
9 our questions earlier today in the reactor systems
10 area, are they preparing anything that they might want
11 to bring in as an illustration of an example of how
12 thorough their investigation was or something? Or are
13 they just leaving it open in case we might ask
14 something? Are they preparing anything.
15 MR. FINLEY: No, they are not preparing
16 anything.
17 MEMBER WALLIS: They're not preparing
18 anything.
19 MR. MIRANDA: No.
20 MEMBER WALLIS: Sometimes that happens
21 when we ask questions, they say oh I wished I'd
22 actually been able to present something, and they --
23 CHAIRMAN DENNING: But I'm not suggesting
24 that you now initiate --
25 MEMBER WALLIS: I'm not suggesting. I'm

1 just asking if -- I'm just asking if they had that on
2 their agenda. I wasn't soliciting it. I was just
3 curious if they --
4 MEMBER SIEBER: It might not be a bad
5 idea, though, to pick some aspect of the review and go
6 through it carefully with us to show what the basis
7 is, what things you reviewed from the licensee and how
8 you draw your conclusions, what kind of calculations
9 if any do you make on your own as confirmatory. And
10 a way to describe the basis for a conclusion that says
11 everything is okay. I think if we just ran through
12 that once, perhaps it would help us.
13 CHAIRMAN DENNING: But if you want to
14 defer that until we meet again in a month, you can do
15 that. It makes more sense than trying to --
16 MEMBER SIEBER: You probably couldn't put
17 it together for tomorrow.
18 MR. MIRANDA: Yes. Basically what it would
19 be is an ad hoc discussion --
20 MEMBER SIEBER: That wouldn't do.
21 CHAIRMAN DENNING: Okay. In that case we
22 are adjourned until tomorrow.
23 (Whereupon, at 4:53 p.m. the Subcommittee
24 was adjourned, to reconvene at 8:30 a.m. on March 16,
25 2006.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards Subcommittee on Power Uprates Meeting

Docket Number: n/a

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Charles Morrison
Official Reporter
Neal R. Gross & Co., Inc.

ACRS Subcommittee on Power Uprates

NRC Staff Review of Extended Power Uprate Application
For
R.E. Ginna Nuclear Power Plant

March 15 - 16, 2006

Introduction

Patrick D. Milano
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Divsion of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Topics for March 15

- Background for Application
- Overview of the Application
- Fuel and Core Design
- Safety Analyses
  - Reactor Systems
  - Dose Consequences
- Risk Evaluation

Topics for March 15

- Electrical Impacts
  - Grid and Power Delivery
- Mechanical and Materials
- RV and Boundary Materials
- Vibration, Corrosion, and Erosion
- Mechanical Systems

Topics for March 16

- Overview of Operations and Testing
- Human Factors Review
- Power Acension and Testing

Introduction

- Pre-application Submittals
  - Relaxed Axial Offset Control
  - Main Feedwater Isolation Valves
  - Revised LOCA Analyses
- Application with supplements
  - July 7, 2005 application
  - Licensing Report
- Schedule and implementation
- Open Items

Ginna EPU Reactor Systems

PWR Systems Branch
Division of Safety Systems

- Kent Wood, Reactor Systems Engineer
  - Fuel Assemblies and Nuclear Design
  - Thermal-Hydraulic Design
- Samuel Miranda, Reactor Systems Engineer
  - Transient Analyses, Overpressure protection, Non-LOCA accidents
  - ATWS, New and Spent Fuel Storage
- Leonard Ward, Sr. Reactor Systems Engineer
  - Large-Break LOCA
  - Small-Break LOCA

Ginna EPU Reactor Systems

Fuel and Reactor Systems Evaluation
Fuel Assemblies

- Changing Fuel Design
  - Current - Optimized Fuel Assembly (OFA) with ZIRLO cladding
  - New - 14X14 422V+ with ZIRLO Cladding
- Notable Differences between OFA and 422V+
  - 14X14 422V+ assemblies have more fuel
  - 14X14 422V+ fuel rods are bigger
  - 14X14 422V+ RCCA position is different
- NRC Staff Focus
  - Transition Effects
  - SRP 4.2 Acceptance Criteria

Ginna EPU Reactor Systems

Fuel and Reactor Systems Evaluation
Nuclear Design

- Changing Nuclear Design Parameters
  - Nuclear Enthalpy Rise Hot Channel Factor
  - Heat Flux Hot Channel Factor
  - Shutdown Margin
  - Moderator Density Coefficient
  - Total Rod Worth
- Acceptablity Shown by Transient Analyses
- Continuity: WCAP- 9272-P-A, "Westinghouse Reload SafetyEvaluation Methodology"

Ginna EPU Reactor Systems

Fuel and Reactor Systems Evaluation
Thermal-Hydraulic Design

- Changing Fuel Design from OFA to 14X14 422V+
- Notable Differences between OFA and 422V+
  - 14X14 422V+ Assembly Loss Coefficient is 20% less
  - VIPRE-01 replaces THINC IV Codes
  - Transition Core DNBR Penalty
- Notable Similarities
  - RTDP and WRB-1 DNB Correlation
  - STDP and W-3 DNB Correlation
  - DNBR Limits

Ginna EPU Reactor Systems

Fuel and Reactor Systems Evaluation

Transient Analyses

- Overpressure Protection
  - During Power Operation
    - Licensee performed acceptable RETRAN analyses to SRP 5.2.2 criteria
    - NRC staff verified conculsions with LOFTRAN. Peak RCS pressure, after reactor trip on 2nd signal (OTΔT), is 2725 psia.
    - Safety valves continue to be adequate under EPU conditions
  - During Low-Temperature Operation
    - Following reviewed and accepted during May 2004 License Renewal
    - RV Materials Surveillance Program
    - P-T Limits and USE
    - Pressurized Thermal Shock
    - Overpressure Protection during low-temperature operation
  - EPU will Increase Decay Heat
    - Heat addition transient is very fast, so decay heat increase has negligible effect
    - Mass addition transient, the limiting transient, not affected by decay heat increase

Ginna EPU Reactor Systems

Fuel and Reactor Systems Evaluation
Non-LOCA Accidents

- Basically followed the guidelines of RS-001
- Analysis results satisfied the applicable GDCs
- Most events analyzed with RETRAN and VIPRE; not LOFTRAN and THINC
- Important to analyses and evaluations:
  - 1817 MWt (19% uprate) assumed in analyses to allow for a future MURP
  - Steam generators replaced in 1996
  - License renewal in 2004 (term extended to 2029)
  - Fuel transition concurrent with EPU
  - Full-power Tavg operating window (564.6 °F to 576.0°F)
  - Assumed up to 10% tube plugging in steam generators

Ginna EPU Reactor Systems

Analyzed Events:

- Boron Dilution
- Feedwater System Pipe Breaks
- Flow Coastdown Accident
- Increase in FW Flow
- Loss of Normal Feedwater Flow
- RCCA Drop
- RCCA Ejection
- Steam Generator Tube Rupture
- Uncontrolled RCCA Withdrawal at Power
- Combined SG ARV and Feedwater Control Valve Failures
- Emergency Core Cooling System and LOCAs
- Inadvertent Opening of a Pressurizer Safety or Relief Valve
- Locked Rotor Accident
- Loss-of-External-Electrical Load
- Loss-of-Offsite-ac-Power to the Station Auxiliaries
- Rupture of a Steam Pipe – HFP and HZP Core Responses
- Uncontrolled RCCA Withdrawal from a Subcritical Condition

Ginna EPU Reactor Systems

- Evaluated Events:
  - CVCS Malfunction
  - Decrease in FW Temp
  - Excessive Load Increase
  - Inadvertent Opening of a SG Relief/Safety Valve
  - Loss of Condenser Vacuum
  - Startup of an Inactive RCL
  - Steam Pressure Regulator Malfunction
  - Turbine Trip

Ginna EPU Reactor Systems

Fuel and Reactor Systems Evaluation

- ATWS
  - 10 CFR 50.62 does not require Ginna to install a Diverse Scram System
  - Re-analyzed at 1817 MWt and replacement steam generators
  - Analyzed using LOFTRAN, with primary-to-secondary HT input from NOTRUMP
  - Peak RCS pressure (3193 psig) lower than the ASME Service Level C limit of 3200 psig

- New and Spent Fuel Storage
  - Satisfies each of 8 criteria in 10 CFR 50.68(b), issued in November 1998.
  - Amendment No. 79 (December 2000) permits a credit for soluble boron in the spent fuel pool, and requires that keff be < 1.0 in unborated water and < 0.95 in borated water

Ginna EPU Reactor Systems

- Large-Break LOCA
  - Analysis results for a double-ended guillotine break at the pump discharge:

Parameter	422V+	OFA	10 CFR 50.46 Limits
Cladding Material	ZIRLO™	ZIRLO™ (Cylindrical)	Zircaloy or ZIRLO™
Peak Clad Temperature	1870 F	1814 F	2200 F (10 CFR 50.46(b)(1))
Maximum Local Oxidation	3.4 %	2.5 %	17.0% (10 CFR 50.46(b)(2))
Maximum Total Core-Wide Oxidation (All Fuel)	0.30 %	0.30 %	1.0% (10 CFR 50.46(b)(3))

Ginna EPU Reactor Systems

- Small-Break LOCA
  - Staff's review is not yet complete
  - Results will be provided next month
- Long-term Cooling and Boron Precipitation
  - Staff's review is not yet complete
  - Results will be provided next month

Source Terms and Radiological Consequences Analyses

Brian Lee
Reactor Systems Engineer
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Division of Risk Assessment
Office of Nuclear Reactor Regulation

Source Terms for Radwaste Systems Analysis

- RS-001 Matrix 9, EPU SE Section 2.9.1
- Radiation sources in reactor coolant analyzed for EPU conditions
- Continue to meet requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and GDC-60

DBA Radiological Consequences Analyses

- RS-001 Matrix 9, EPU SE Section 2.9.2
- Previously implemented Alternative Source Term (AST)
  - AST full-scope implementation per 10 CFR 50.67
  - Amendment #87 issued February 25, 2005
- Revised dose analyses assumed proposed EPU conditions
  - 1811 MWt (102% of 1775 Mwt)
- Followed RG 1.183 guidance

DBA Dose Analyses in EPU Submittal

- LOCA, FHA, and TMA (Tornado Missile Accident)
  - Revised analyses were performed due to the sources in the fuel increasing as the power increased
- MSLB, SGTR, LRA, and REA
  - Revised analyses were performed due to change in mass and energy release
- Control room isolation assumed for all DBAs
  - 5400 cfm filtered recirculation
  - 300 cfm unfiltered inleakage

DBA Radiological Consequences Analyses

Conclusion

- Licensee has adequately accounted for the effects of the proposed EPU
- All DBAs meet 10 CFR 50.67 and SRP 15.0.1 dose acceptance criteria both offsite and in the control room
- The staff finds the proposed EPU acceptable with respect to the radiological consequences of DBAs

Ginna EPU Risk Evaluation

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PRA Licensing Branch A
Divsion of Risk Assessment
Office of Nuclear Reactor Regulation

Conclusion on Ginna EPU Risk Review

- Licensee adequately modeled and addressed potential risk impacts of the proposed EPU
  - Most complete EPU risk evaluation this reviewer has seen (see last bullet)
- Risks are acceptable (i.e., within RG 1.174 risk acceptance guidelines)
- The proposed EPU does not create "special circumstances"
- Licensee used their risk evaluation to identify potential changes that would offset any risk increase due to the proposed EPU

EPU Risk Evaluations

- EPU submittals are not risk-informed
- Per RS-001, Rev. 0, "Review Standard for Extended Power Uprates," Matrix 13, "Risk Evaluation," licensees perform risk evaluations to:
  - Demonstrate that risks are acceptable, and
  - Determine if "special circumstances" exist (as defined in SRP 19, Appendix D)
- To date, the staff has not identified any "special circumstances" related to a licensee's proposed EPU, including BWR uprates as high as 20% and PWR uprates as high as 16%

Ginna EPU Risk Evaluation

- Ginna PSA Level I covers:
  - Internal Events, including Internal Floods
  - External Events
  - Shutdown Operations
- Ginna PSA uses a simplified containment event tree to evaluate LERF
  - Follows NUREG/CR-6595 for PWRs with a large dry containment

Identifed Risk Impacts

- Total CDF increases by 12% (to 7.1E-5/year)
- Total LERF increases by 10% (to 5.4E-6/year)

Post-PU Dominant Impacts by Initiating Event Category

	CDF		LERF	
	/yr	% Increase	/yr	% Increase
Internal	1.5E-5	16%	1.5E-6	19%
Flood	1.2E-5	5%	5.5E-7	7%
Fire	3.1E-5	8%	2.9E-6	5%
Shutdown	1.3E-5	21%	4.0E-7	17%

- EPU risk increase driven by:
  - Human actions (63% of increase)
  - Initating events (27% of increase)

Licensee's Use of EPU Risk Information

- Licensee used the Ginna EPU risk evaluation to gain insights and proposed plant modifications and operational improvements that could reduce risk
- 5 risk and cost beneficial changes identified that would likely completely offset EPU risk increase
  - Optimize use of safety injection pumps during fires
  - Mechanically limit RHR HCVs from failing completely open
  - Provide backup air supply to charging pumps
  - Relocate charging pump control power disconnect
  - Install local controls for the turbine-driven auxiliary feedwater pump discharge motor-operated valve

Ginna EPU Risk Review Conclusions

- Licensee adequately modeled and addressed potential risk impacts of the proposed EPU
  - Most complete EPU risk evaluation this reviewer has seen (see last bullet)
- Risks are acceptable (i.e., within RG 1.174 risk acceptance guidelines)
- The proposed EPU does not create "special circumstances"
- Licensee used their risk evaluation to identify potential changes that would offset any risk increase due to the proposed EPU

Going Forward

- Licensees will need to continue to perform the risk evaluations per RS-001
- To better utilize staff resources, future staff EPU risk reviews may be condensed -confirming that the licensee's proposed EPU does not create "special circumstances"
- The staff highly commends Ginna for their risk evaluation and their use of the risk evaluation to identify potential changes that would improve the plant's risk profile
  - The staff recommends that other licensees follow the excellent example set by Ginna

Reactor Vessel, Reactor Internal And Core Support Materials

Neil Ray
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Office of Nuclear Reactor Regulation

Outlines

- Reactor vessel (RV) integrity include:
  - Surveillance capsule program
  - Effects of radiation embrittlement on reactor vessel integrity
- RV internals and core support materials

Surveillance Capsule Program

- Maximum RT_{NDT} using the EPU fluence is greater than 200 ^{0}F and requires five capsules withdrawal, which remains same as current numbers
- Fifth capsule is planned for withdrawal at 5.45 E19 n/cm^2 (E > 1.0 MeV) which is between one to two times the peak EOL fluence

Reactor Vessel Radiation Embrittlement

- Three analyses affected by radiation embrittlement:
  - Pressure-Temperature Limits (P-T)
  - Upper Shelf Energy (USE)
  - Pressurized Thermal Shock (PTS)

Pressure-Temperature Limits

- Current P-T limits are applicable to 28 effective full power years (EFPY) and is based on adjusted reference temperature (ART) using cumulative fluence of 3.11 E19 n/cm ^{2} (E>1.0 MeV)
- Peak reactor vessel EPU fluence at 28 EFPY is 2.91 E19 n/cm^2 (E>1.0 MeV)
- Thus current P-T limits will be valid until 28 EFPY (present ART values are limiting)

Upper Shelf Energy

- All beltline materials are expected to have USE greater than 50 ft-lbs through the end of renewed life except the intermediate-to-lower shell girth weld and the intermediate-to-nozzle shell girth weld
- Analysis shows that the ASME Code, Section XI, Appendix K acceptance criteria have been satisfied for levels A, B, C, and D service loadings
- Staff performed independent analysis and confirmed applicant's conclusions

Pressurized Thermal Shock

- RT_{PTS} value for the limiting circumferential weld will increase from 270.6 °F to 273 °F using EPU fluence
- Thus RT_{PTS} values for the beltline region is within the screening criteria

Reactor Internal and Core Support Materials

- The licensee is following ASME Section XI inservice inspection (ISI) program
- In addition, the licensee made commitments to participate in the industry's research program and will develop an inspection program for the RV internals that is based on the recommendations of the industry initiatives
- These commitments are consistent with Table Matrix-1 of Review Standard RS-001, Revision 0

Conclusions

- The staff has concluded that EPU will not significantly impact the safety margins for the following structural integrity assessments:
  - RV surveillance program
  - P-T limits for the reactor vessel
  - USE assessments for the reactor vessel
  - PTS assessment for the reactor vessel beltline materials
  - Structural integrity assessment of the reactor vessel internal components

Reactor Coolant Pressure Boundary Materials

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Flaw Evaluation and Welding Branch
Division of Component Integrity
Office of Nuclear Reactor Regulation

Scope

- Reactor Coolant Pressure Boundary (RCPB) defines boundary of systems/components that contain high pressure fluids in the reactor
- Review covered the following
  - Specification
  - Compatibility with reactor coolant
  - Fabrication and processing
  - Material susceptibility to degradation
  - Degradation management programs
  - EPU impact on failure mechanisms
  - LBB analyses

Degradation Mechanisms and Conclusions

- Austenitic SS
  - IGSCC - Sensitized Microstructure
  - TGSCC- Introduction of Halogens
  - 8.6°F increase in Reactor Coolant Hotleg temperature does not introduce a new failure mechanism
  - Slightly elevated chemistry within Li 3.5ppm within EPRI guidelines
- Alloy 600/82/182 Components
  - PWSCC-Sensitized Microstructure
  - Reactor Head replaced 2003 with Alloy 690
  - Other susceptible components will be monitored under LRA Aging Management Programs
  - Programs approved by staff in NUREG-1786
  - Effects of PWSCC will be adequately managed

Degradation Mechanisms and Conclusions

- Cast Austenitic Stainless Steels
  - Thermal Aging
  - WCAP-14575-A proposed programs for managing effects of thermal aging
  - Programs were reviewed and accepted under Section 3.3.3 of LRA SE NUREG-1786
  - WCAP-15837 performed a specific LBB flaw evaluation as structural design basis for LRA
  - Shown that maximum stresses at critical locations impacted <1%
  - 8.6°F increase had negligible effects on flaw stability analysis
  - WCAP-15837 accepted by staff SE in NUREG-1786

Leak Before Break

- Determined if RCPB LBB analyses were impacted by EPU under WCAP-15837
- LBB analyses of primary loop piping and RCP casing performed in 2002 for Ginna LRA
- Licensee evaluated impact of EPU on conclusions reached in 2002 LBB analysis approved by staff in NUREG-1786
- SRP Section 3.6.3 lists following:
  - Margin of 10 on Leak Rate (EPU -10)
  - Margin of 2.0 on Flaw Size (EPU- 2)
  - Margin of 1.0 on Loads (EPU - 1.0)

Conclusions

- Licensee has adequately evaluated effects of EPU on RCPB materials - no new failure mechanisms due to EPU
- Licensee has identified appropriate degradation management programs to address effects of changes in system operating temperatures
- Demonstrated that LBB Analyses remain valid under EPU conditions
- GDC-1, -4, -14, -31, 10 CFR Part 50, App. G, and 10 CFR 50.55a requirements met under Matrix 1 of RS-001

Mechanical and Civil Engineering
Components and Support Degradation Mechnaisms

Kamal Manoly
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Cheng-Ih (John) Wu
Senior Mechanical Engineer
Mechanical Engineering Branch

Mechanical and Civil Engineering

Components Evaluated

- Reactor Vessel, Internals, Nozzles, Supports
- Control Rod Drive Mechanisms
- Replacement Steam Generator, Reactor Coolant Pump, Pressurizer and Supports
- NSSS and BOP Piping Systems and Supports
- Safety Related Valves (MOVs, AOVs, and SRVs)

Mechanical and Civil Engineering

Scope of Review

- Methodology, Loads
- Stresses and Cumulative Usage Factors
- Acceptance Criteria, Codes and Addenda
- Functionality and Impact of EPU on GL 89-10 for MOVs, GL 95-07 for Pressure Locking and Thermal Binding for power operated valves
- Effects of EPU on License Renewal Evaluations
- NSSS and BOP Piping Systems and Supports

Mechanical and Civil Engineering

- Use of approved LBB criterion
  - Eliminates postulated breaks for piping greater than 10 inch lines
  - Limiting breaks considered for EPU are in the 3-inch pressurizer spray line on the cold leg, the 2-inch safety injection line on the hot leg, and the 4-inch upper plenum injection line connections to the vessel
- Finite element analysis performed using WESTDYN code for revised design loads
- Calculated stresses compared to ANSI B31.1 and ASME Code Section III limits.

Mechanical and Civil Engineering

- CUFs for pressurizer surge line piping calculated based on 60 years and compared to ASME limit of 1.0.
- As a result of EPU evaluation, licensee upgraded nine supports and added one support in MSL and added one support in FW line for the effects of increased flow rate.

Mechanical and Civil Engineering

Degradation Mechanisms

- FIV effect on steam separator is expected to increase at EPU. However judged to be acceptable based on the design basis steam flow rate of the replacement steam generator that is bounding for EPU.
- Slight increase in FIV on the U-bend tubing, but remains within allowable limits (i.e., maximum stability ratio less than the limit of 1.0)

Mechanical and Civil Engineering

Degradation Mechanisms

- Flow Induced Vibration
  - MSL and FW piping instrumented at critical locations to monitor vibration levels at current rated power and during EPU power ascension up to the full authorized power level. The vibration monitoring and collected data will be evaluated according to ASME OM3
  - FIV effect on steam separator expected to increase at EPU. However, judged to be acceptable based on the design basis steam flow rate of the replacement steam generator that is bounding for EPU
  - Slight increase in FIV on the U-bend tubing, but remains within allowable limits (i.e., maximum stability ratio less than the limit of 1.0)

Mechanical and Civil Engineering

Steam Generator Dryer/Separator

- **Flow rate and pressure used in testing bound EPU conditions**
- Past inspections performed in operating plants not found FIV fatigue
- Integrity of rugged steam separators improved in new SG design
- Low flow velocity makes potential for loose parts to enter main steam line unlikely
- Low velocity and high stiffness reduces potential for FIV
- Capability to identify degradation o Sgs through plant monitoring and outage inspections
- Filtering screen ensures collection of small parts in steam flow in unlikely event of degradation of SG internal components

Steam Generator Tube Integrity and Chemical Engineering Topics

Gregory Makar
Materials Engineer
Steam Generator Tube Integrity and
Chemical Engineering Branch
Division of Component Integrity
Office of Nuclear Reactor Regulation

Flow Accelerated Corrosion (FAC)

- Corrosion rates for FAC-susceptible components are determined by parameters such as temperature, flow velocity, moisture content, and component material.
- For some components, some of these parameters will change at EPU conditions.

Flow Accelerated Corrosion (FAC)

- Components have been added to the program based on the potential for increased FAC rate at EPU conditions (higher temperature and velocity)
- CHECWORKS computer models are being updated prior to implementing the EPU.
- At EPU conditions the FAC program remains consistent with industry guidelines.

Steam Generator Tube Inservice Inspection

- Ginna has replacement steam generators with thermally treated Alloy 690 tubes and stainless steel tube support components (1996)
- Operating parameters will remain within the range found at other plants with Alloy 690 steam generator tubes.
- The inspection program will continue to manage degradation effectively at EPU conditions.

Steam Generator Blowdown System (SGBS)

- At EPU conditions the SGBS flow rate is expected to remain in the historical range of 40 to 100 gallons per minute per SG.
- The ability of the SGBS to remove impurities from the secondary coolant will not be reduced at EPU conditions.
- Corrosion rates of SGBS components will continue to be monitored under the Flow Accelerated Corrosion Program.

Chemical and Volume Control System

- Changes in letdown, charging, and makeup rates may be needed due to:
  - Expected increase in boration requirement
  - Potential increase in crud buildup
- These changes are within the present capability of the system.

Protective Coatings (Paints) Organic Materials

- Original coating application predates RG 1.54 and ANSI N101.4. Coatings were procured and applied according to Westinghouse and plant specifications.
- Containment temperature, pressure, pH, and radiation dose at EPU conditions are bounded by the qualification conditions for coating degradation and adhesion.
- EPU conditions do not increase the amount of hydrogen and organic gases generated by organic materials under DBA conditions.

Balance-Of-Plant (BOP) Systems

Raul Hernandez
Reactor Systems Engineer
Balance of Plant Branch
Division of Safety Systems
Office of Nuclear Reactor Regulation

Scope of Review for BOP Systems

- Review per RS-001, Matrix 5
  - Internal Hazards
  - Fission Product Control
  - Component Cooling and Decay Heat Removal

Scope of Review for BOP Systems

- Review per RS-001, Matrix 5 (continued)
  - Balance-of-Plant Systems
  - Waste Management Systems
  - Emergency Diesel Fuel Oil Storage & Light Loads
- BOP test considerations

BOP Systems
Review Areas of Emphasis

- Spent Fuel Pool Cooling
- Service Water System/Ultimate Heat Sink
- Auxiliary Feedwater System
- Condensate and Feedwater System

Spent Fuel Pool Cooling

- SFP heat load will not exceed the cooling capability of the SFPC system (administrative controls are used).
- Reduced SFP make-up capability of the alternate source will continue to be adequate.
- Commitments:
  - Update TS to reduce number of fuel assemblies stored in the SFP.
  - Update UFSAR to reflect lower make-up capability.

Service Water System & Ultimate Heat Sink

- Lake Ontario is credited as the ultimate heat sink (UHS).
- For Post-LOCA mitigation (recirculation phase) two SW pumps are required operable instead of one.
- No modifications are required.

Commitment

- Revise TS to require two SW pumps to be operable in each train.

Auxiliary Feedwater System

- Preferred AFW required flow increased by 5 GPM , and the Stand-by AFW required flow increased by 25 GPM
- No modifications are required for the Preferred AFW
- Modified control valve trim for the Stand-by AFW system, to be verified by testing

Condensate and Feedwater System

- No safety challenges are created.
- Major modifications include the feedwater regulating valves, feedwater pumps, and condensate booster pumps.
- System tuning
  - MF pump suction pressure setpoint
  - MF pump NPSH calculator setpoint
  - A delay is added to the LP heater bypass valve open circuit
- Power ascension and some limited transient testing to be completed

BOP Systems - Summary

- The staff finds the proposed EPU to be acceptable with respect to BOP area, based on:
  - evaluation results
  - commitments
  - Power ascension and transient test program

Human Performance

Garry Armstrong, Jr.
Human Factors Engineer
Operator Licensing and Human Performance Branch
Division of Inspection and Regional Support
Office of Nuclear Reactor Regulation

Human Factors Engineering Evaluation

- Areas of Review
  - Programs, procedures, training, and human system interface design features that are related to operator performance
- Purpose
  - Assure that operator performance is not adversely effected by the proposed Extended Power Uprate (EPU)

Regulatory Criteria

- RS-001, "Review Standard for Extended Power Uprates Draft Review Standard for Power Uprates," Matrix 11
- 10 CFR 50.120
- 10 CFR Part 55
- Generic Letter 82-33

- Standard Review Plan Chapter 18.0, "Human Factors Engineering"

RS-001, Matrix 11, Standard Questions Related to Affects of EPU

- Emergency and Abnormal Operating Procedures
- Operator Actions Sensitive to Power Uprate
- Control Room Alarms, Controls, Displays
- The Safety Parameter Display System (SPDS)
- Operator Training Program and Control Room Simulator

Emergency and Abnormal Operating Procedures

- Some EOP automatic action verification steps will be streamlined in E-0 procedure to expedite diagnosis and plant stabilization
- Functional Restoration (FR) procedure FR-H.1, "Response to Loss of Secondary Heat Sink," will be revised to provide earlier initiation of the Standby Auxiliary Feedwater (SAFW) System to mitigate consequences of a high energy line break
- Appendix R mitigation procedures will be enhanced for effectiveness of operator actions and to incorporate the physical plant changes

Operator Actions Sensitive to Power Uprate

- EPU has minimal effect on operator responses to transients/accidents
- FR-H.1 procedure revised to direct operator to immediately initiate SAFW when normal AFW is lost
- Times were unaffected for overall operator actions, but procedure and plant modifications being made to maintain operator capability to perform actions in the established time
  - Example: S/G dryout under EPU conditions reduced from 50 minutes to 35 minutes. Operator is currently required to establish feedwater flow within 30 minutes. Several local valve manipulations being eliminated to ensure operator can establish feedflow to in tact S/G within 30 mins

Operator Actions Sensitive to Power Uprate (continued)

- All current operator actions times will be verified using the simulator and plant walk throughs prior to the EPU
- Operator actions related to Small Break LOCA under EPU conditions to be evaluated by NRC at a later time since the review is still in progress

Control Room Alarms, Controls, Displays

- Licensee provided detailed list of items that will have setpoint changes related to the EPU
- New controls added for the two new Main Feedwater Isolation Valves (MFIV)
- The main areas that the EPU will affect:
  - Instrument Loops
  - Alarm Response Procedures
  - Plant Process Computer System Setpoints
  - Controls and Control Systems
- Modifications will be completed using human factors review and operator input
- Training on modifications will be provided

Safety Parameter Display System (SPDS)

- Changes related to the EPU include:
  - RCS Subcooling margin to be reduced
  - Condensate Storage Tank minimum required level to be increased
  - Critical Safety Function status trees to be reviewed and revised
- Changes to SPDS will be made before EPU implementation
- Training will be conducted before EPU implementation

Operator Training Program and Control Room Simulator

- Training will cover plant modifications, procedure changes, start-up test procedures, and changes to parameters, setpoints, and scales in the control room
- Training and simulator changes will be completed before EPU implementation
- Simulator will be validated against expected EPU responses and operating data from start-up tests
- Simulator fidelity will be implemented in accordance with ANSI/ANS 3.5 1998 using RETRAN
- Appendix R procedure changes involving local manipulations will be validated using walk through simulations in the field

Conclusions

- The licensee has:
  - Accounted for the effects of the proposed EPU on available time for operator actions
  - Taken or has committed to take appropriate actions to assure that operator performance is not adversely affected by the proposed EPU
- The licensee will continue to meet applicable NRC requirements related to human performance
- The NRC finds the licensee's proposed EPU acceptable with respect to human factors except as noted regarding SBLOCA

Power Ascension and Test Program

Aida Rivera
Operations Engineer

Paul Prescott
Senior Operations Engineer

Quality and Vendor Branch
Divsion of Engineering
Office of Nuclear Reactor Regulation

EPU Test Program

- Standard Review Plan (SRP) 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," provides guidance for testing programs based on Regulatory Guide (RG) 1.68 and plant specific initial test program.
- EPU test program should include testing sufficient to demonstrate structures, systems, and components (SSCs) will perform satisfactorily at the requested power level.
- Staff guidance considers original power ascension test program and EPU related plant modifications.
- Staff guidance acknowledges that licensees may propose alternative approaches to testing with adequate justification.

EPU Test Program

- <u>Regulatory Guide 1.68 Testing "Objectives"</u>
  - Operator training and familiarization
  - Confirmation of design and installation of equipment
  - Benchmarking of analyses codes and models
  - Confirmation of the adequacy of emergency and operating procedures.

Ginna EPU Test Program

- Ginna will perform a manual turbine trip test at approximately 30% EPU power to verify the plant's dynamic transient response and control system settings.
  - pressurizer level and pressure control,
  - steam generator water level control,
  - steam dump control, and
  - rod control
- Acceptance criteria for this test will include:
  - verification that no reactor trip occurs,
  - that the pressurizer safety valves, main steam safety valves and pressurizer power operated relief valves do not open, and
  - that the plant dynamic response is stable and converging on a range that supports safe operation at low power.

EPU Test Program

- Previously accepted justifications for not performing LTT were applicable to Ginna EPU application.
  - The licensee's test program will monitor important plant parameters during EPU power ascension.
  - TS surveillance and post-mod testing will confirm the performance capability of the modified components.
  - Operating history and experience at other uprated LWRs.
  - LTT is not needed for Code analyses benchmarking.

EPU Test Program

Conclusion

- SRP 14.2.1 allows for justification for not performing EPU Power Ascension Tests.
- Fourteen domestic LWRs have implemented staff approved EPUs (up to 120% OLTP) without performance of LTT.
- Ginna will perform manual turbine trio test at approximately 30% EPU power to verify integrated plant response.
- Staff concludes that proposed test program provides adequate assurnace that plant will operate in accordance with design criteria and that SSCs affected by EPU will perform satisfactorily in service.

Constellation Energy

Ginna Extended Power Uprate

ACRS Thermal Hydraulic Phenomena Subcommittee Meeting

March 15, 2006

The way energy works.™

Mark Flaherty
Vice President – Nuclear Technical Services (Acting)
Introduction/Agenda Review

Ginna Extended Power Uprate

Agenda

• Introduction	Mark Flaherty
• Plant Changes	Mark Finley
• Process	Dave Wilson
• Fuel and Core	Gordon Verdin
• Safety Analysis	Mark Finley
• Risk Evaluation	Rob Cavedo
• Mechanical Impacts	Jim Dunne
• Electrical Impacts	Joe Pacher
• Operations and Testing	Roy Gillow
• Conclusion	Mark Flaherty

Introduction - Agenda

- Design and Operating History
- Preparations for Uprate
- Executive Oversight

Ginna Extended Power Uprate

Introduction – Design and History

- Westinghouse two-loop 1520 MWt NSSS design
- Commercial operation in 1970
- 1300 MWt original licensed power
- 1520 MWt licensed in 1972
- 1775 MWt Extended Power Uprate (1)

(1) Kewaunee is operating at 1772 MWt

Ginna Extended Power Uprate

Introduction – Preparations for Uprate

- Replaced steam generators 1996
- Replaced reactor vessel head 2003
- Experienced project team:
  Westinghouse, Stone & Webster, Siemens
- Executive oversight:
  corporate, vendor, industry experts

Ginna Extended Power Uprate

Introduction – Executive Oversight

- Constellation senior management closely involved
- Executive Oversight Committee (EOC) formed – has met eight times to date
- Industry experts engaged
- Necessary resources made available – e.g. risk beneficial plant changes

Mark Finley
Project Director
Plant Changes

Plant Changes - Agenda

- Operating Parameters
- Modifications
- License Amendments
- Use of Operating Experience

Ginna Extended Power Uprate

Plant Changes – Operating Parameters

	EPU		Pre-EPU		
	Condition	Enthalpy	Condition	Enthalpy	Change
Core Power (MWt)	1775		1520		+16.8%
Taverage	574°F		561°F [1]		+13°F
Tcold / h cold (BTU/lb)	541°F	536.1	532°F	525.1	+9°F
Delta T	66°F		58°F		+8°F
Delta h		87.1		74.0	+17.5%
Thot / h hot (BTU/lb)	607°F	623.1	590°F	599.1	+17°F
Coolant Mass Flow (lb/hr)	6.96E+07		7.01E+07		-0.7%
Pressurizer Pressure	2250 psia		2250 psia		
SG Power (MWt)	1781		1526		+16.8%
FW In / h in (BTU/lb)	432°F	410.5	425°F	402.9	+7°F
Delta h		788.8		797.2	-1.2%
Stm Out / h out (BTU/lb)	798 psia	1199.4	770 psia	1200.1	+28 psia
Stm Mass Flow (lb/hr)	7.71E+06		6.53E+06		+18.0%

(1) Taverage was 573.5°F prior to SG replacement in 1996

Ginna Extended Power Uprate

Plant Changes – Significant Modifications

- Fuel assembly
- Feed isolation valve actuators
- Standby AFW discharge valve internals
- High pressure turbine and turbine control valves
- Main feedwater and booster pumps, regulating and bypass valves
- Cooling for main generator, step-up transformer, isophase ducts and underground oil cables
- Moisture Separator Reheater relief system
- Various heater drain minor modifications
- Various BOP support minor modifications
- Risk beneficial modifications:
  charging pump backup air, charging and TD AFW controls

Ginna Extended Power Uprate

Plant Changes – License Amendments

Change	EPU	Current
Core Thermal Power	1775 MWt	1520 MWt
LOCA Methods	BE LOCA/ASTRUM	BE LOCA/SECY-83-472
Axial Offset Control	RAOC (Relaxed)	CAOC (Constant)
Max Boron – Accumulator / RWST	3050 ppm	2600 ppm
Min Volume – Accumulator	1090 ft^3	1111 ft^3
Min Volume - Condensate Storage Tank	24350 gal	22500 gal
Feed Isolation Time (Back-up Valve)	30 sec	60 sec
Safety Setpoints	Later in 'Safety Analysis'	Later in 'Safety Analysis'

Ginna Extended Power Uprate

Plant Changes – Industry Operating Experience

- Vibration induced failures
- Turbine rubs
- Turbine control – valves wide open
- Isophase bus duct air flow and cooling
- Step-up transformer cooling
- Power measurement
- Setpoint Operating Margin: Steam Pressure, T_{Hot} and ΔT

Dave Wilson
Licensing Lead
Process

Process - Agenda

- RS-001
- Additional Sections
- Staff Interactions
- Reviews

Ginna Extended Power Uprate

Process – RS-001

- RS-001

  Process was:

  Give them what they asked for

  <u>AND</u>

  Give them what they need

Process – Additional Sections

- Added sections to cover unique areas
  - Renewed Plant Operating License
  - Systematic Evaluation Program and the CLB
  - Licensing Report Introduction – road map/lessons learned

Ginna Extended Power Uprate

Process – Staff Interactions

- Timely, Frequent and Meaningful Staff Interactions
  - Pre-submittals for long lead time evaluations – Licensing Report written to account for LARs in queue
  - Lessons learned incorporated
  - No surprises, prompt communications followed by working through issues

Ginna Extended Power Uprate

Process – Reviews

- Reviews
  - Rigorous Owner Acceptance Reviews of Vendor Outputs
    - Acceptance reviews proceduralized
    - Quality Assessment reviews to verify correctly implemented
  - NRC Reviews
    - Questions relevant and meaningful
    - Line of reasoning (basis for question) provided to minimize miscommunication and delays

Gordon Verdin
Fuel Lead
Fuel and Core

Fuel and Core - Agenda

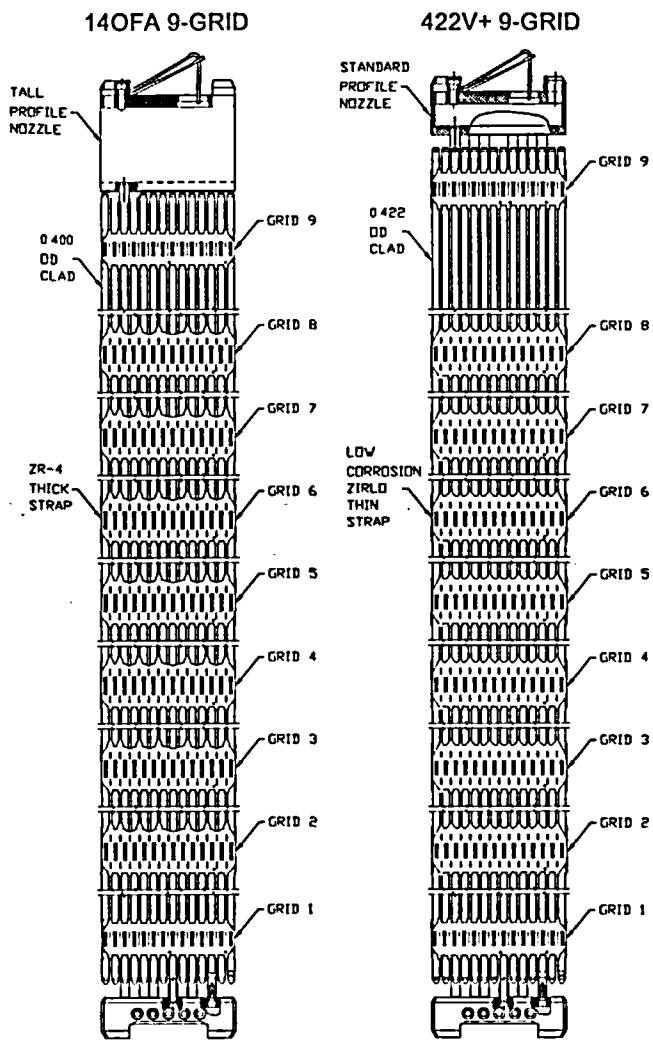
- Fuel Assembly Design
- Core Design
- Core Operating Limits

Ginna Extended Power Uprate

Fuel Assembly Design

Existing Ginna Fuel (OFA)

- 0.400" OD ZIRLO™ Clad
- 141.4" Fuel Stack
- 2.6% enriched annular axial blankets
- ZrB_2 burnable absorber
- Tall Top Nozzle
- RRB Top Grid
- OFA Zirc-4 Mid-grids (7) (0.026/0.032)
- HF Bottom Grid
- Double Dashpot Guide Thimbles
- 346 kgU



Uprate Ginna Fuel (422V+)

- 0.422" OD ZIRLO™ Clad
- 143.25" Fuel Stack
- 2.6% enriched annular axial blankets
- ZrB_2 burnable absorber
- Standard Top Nozzle
- RRB Top Grid
- 422V+ ZIRLO™ Mid-grids (7) (0.018/0.026)
- HF Bottom Grid
- Tube-in-Tube Guide Thimbles
- 396 kgU

Ginna Extended Power Uprate

Ginna 422V+ Fuel Assembly Design

- New assembly provides for additional Uranium loading and recovers DNBR margin for EPU
- 9-grid design based on field-proven 7-grid 422V+ design (Point Beach, Kewaunee) with several enhancements:
  - Balanced mixing vanes to reduce resonant self-excited vibration
  - Increased dimple contact areas to reduce wear rates
  - Tube-in-tube guide thimbles to simplify construction and reduce IRID probability
  - Modified grid material annealing to reduce hydrogen pickup and irradiation growth
  - 0.2" increase in fuel rod length, 0.75" reduction in fuel stack height to increase RIP margin

Ginna Extended Power Uprate

Ginna 422V+ Fuel Assembly Design

- Ginna 422V+ fuel assembly has undergone extensive testing
  - FACTS (vibration, hydraulic losses, forces)
  - VIPER (long-term wear testing with OFA partner)
  - VISTA (high-frequency grid strap vibration)

Ginna Extended Power Uprate

Core Design

- Ginna will have two transition core cycles which contain OFA fuel assemblies
- Probable 422V+ feed assembly quantities
  - 53 in Cycle 33 (first transition cycle)
  - 48 in Cycle 34
  - 45, 44, 45, 44, … (subsequent all-422V+ equil^{m} cycles)
- Low-leakage core loading patterns will continue to be used
- EPU analyses were performed for a T_{AVG} range from 564.6°F to 576°F; reload designs will use 574°F T_{AVG} to satisfy turbine throttle pressure requirements and ensure full-power capability with new HP turbine

Ginna Extended Power Uprate

Core Operating Limits

- Axial power distribution Technical Specification will transition from CAOC to RAOC with uprate
- No changes to thermal design flow, although actual volumetric flow is expected to increase marginally due to reduced hydraulic resistance of 422V+
- Nominal 100% RTP heat flux hot channel factor will increase from current limit of 2.45 to 2.6
- Nominal 100% RTP enthalpy rise hot channel factor will decrease from current limit of 1.75 to 1.72 (422V+); OFA limits are lower due to transition core penalties
- Shutdown margin requirements are reduced by addition of an additional feedwater isolation valve (1300 pcm versus 2400 pcm previously)

Mark Finley
Project Director
Safety Analysis

Safety Analysis - Agenda

- Safety Setpoints
- Control Settings
- Methods
- LOCA Events
- Non-LOCA Events
- Containment
- Dose Assessment
- Conclusion

Safety Analysis – Safety Setpoints (Analytical)

Setpoint	EPU	Current
High Flux Trip	≤ 115%	≤ 118%
Steam Line Isolation Hi-Hi	≤ 5.97×10^6 lbm/hr	≤ 3.70×10^6 lbm/hr
Steam Line Isolation Hi	≤ 1.50×10^6 lbm/hr @ ≥ 530°F	≤ 0.66×10^6 lbm/hr @ ≥ 543°F
Pressurizer Safety Lift Setting	≤ 2542 psig	≤ 2544 psig
Safety Injection	≥ 1700 psig	≥ 1715 psig
Containment Spray	≤ 33.5 psig	≤ 32.5 psig
P-8 Permissive (Single loop low flow)	≤ 35%	≤ 50%

Safety Analysis – Control Settings

Setting	EPU	Current
Pressurizer Level – Full Power - Zero Power	56% 20%	50% 35%
T_{Avg} – Full Power - Zero Power	574°F 547°F	561°F 547°F
Rod Control - Low Power Mismatch Gain - High	0.3 °F/% – 0.6 °F/% 1.5 °F/% - 3 °F/%	1.5 °F/% – 3 °F/% 5 °F/% - 10 °F/%
Steam Dump Modulation - Turbine Operating - Turbine Tripped	 4°F – 11°F 0°F – 11°F	 5°F – 20°F 0°F – 15°F
T_{Hot} Filter	4.5 sec	0 sec

Safety Analysis – Methods

Method	EPU	Current
Large Break LOCA	BE LOCA/ASTRUM	BE LOCA/SECY-83-472
Small Break LOCA	NOTRUMP	NOTRUMP
Non-LOCA	RETRAN	LOFTRAN
Control System Transients	LOFTRAN	LOFTRAN
Containment: LOCA MSLB	GOTHIC GOTHIC	GOTHIC COCO
Dose Assessment	AST	AST

Ginna Extended Power Uprate

Safety Analysis – Non LOCA

	Event	Criteria	Result
Overheating (Reduced Primary Cooling)	Loss of Flow (Cond II)	DNBR ≥1.38	1.385
	Locked Rotor (Cond IV)	Pres ≤2997 psia	2782 psia
Overheating (Reduced Secondary Cooling)	Loss of Load (Cond II) (Bounds Loss of Feed)	Pres ≤2748.5 psia	2747 psia (No pzr fill)
	Feed Line Break (Cond IV)	No T_{SAT} in HL	2°F subcool
	ATWS	Pres ≤3200 psig	3193 psig
Overcooling	MSLB @ Power (Cond IV) (Bounds Increased FW/ARV)	DNBR ≥1.38 LHR ≤22.7 kw/ft	1.39 22.67 kw/ft
Reactivity Addition	Rod W/D @ Power (Cond II)	DNBR ≥1.38 Pres ≤2748.5 psia	1.384 2748.1 psia
	Rod Ejection (Cond IV)	≤200 cal/gm	178 cal/gm

Ginna Extended Power Uprate

Safety Analysis – LOCA

- Large Break: PCT 1870°F
- Small Break PCT 1167°F

Ginna Extended Power Uprate

Safety Analysis – Containment

- LOCA: 54.2 psig
- MSLB: 59.6 psig
- Design: 60 psig (1)

(1) Structural Integrity Test done at 72 psig after SG replacement in 1996

Ginna Extended Power Uprate

Safety Analysis – Dose Assessment

- Ginna implemented AST and CREATS upgrades in 2005
- Two trains HVAC added with radiation monitors
- Tracer gas test completed with acceptable results (21 cfm actual with 300 cfm assumed)
- AST source terms consistent with RG 1.183
- Updated X/Qs with recent meteorological data
- Calculated doses for EPU are within guidelines of 10CFR50.67 for off-site and control room

Ginna Extended Power Uprate

Safety Analysis – Dose Assessment Results (Rem TEDE)

Accident	EAB Max. 2-hr	LPZ	Offsite Limit	Control Room (5 rem limit)
MSLB w/concurrent spike	0.45	0.12	2.5	0.58
MSLB w/pre-existing spike	0.07	0.03	25	0.17
Locked Rotor	1.16	0.35	2.5	1.87 (1)
REA (containment + secondary)	1.34	0.41	6.3	1.83
SGTR w/concurrent spike	0.17	0.03	2.5	0.22
SGTR w/pre-existing spike	0.44	0.06	25	0.94
LBLOCA (containment + ECCS)	3.1	1.2	25	4.6 (1)
FHA in containment	0.61	0.07	6.3	1.4
FHA in aux. bldg	0.17	0.02	6.3	0.12
TMA	0.03	0.01	6.3	0.63

(1) Change greater than 10% of remaining margin

Safety Analysis – Conclusion

- All safety analyses meet acceptance criteria
- NSSS and Emergency Safety Features are robust
- Results are consistent with Kewaunee

Rob Cavedo
Risk Lead
Risk Evaluation

Risk Evaluation - Agenda

- Scope
- Method
- Results
- Conclusion

Ginna Extended Power Uprate

Risk Evaluation - Scope

- Address Impact On:
  - Initiating Event frequency
  - Success criteria
  - Equipment failure rates
  - Operator response times and Human Reliability Analysis (HRA)
- To Calculate the CDF and LERF Changes On:
  - Internal events
  - External events
  - Shutdown

Risk Evaluation - Method

- Initiating Event Frequency
  - No new PSA initiators
  - Frequencies adjusted based on Engineering Evaluations
- Success Criteria
  - PCTRAN analyses to adjust success criteria as needed
  - Bleed-and-Feed Adjusted

Risk Evaluation - Method

- Equipment Failure Rates
  - Comprehensive reviews of equipment performed
  - Systems operate within allowable limits
  - No significant impact is expected to the likelihood of post-trip Equipment Failure Rates
  - Existing monitoring programs and model update will account for any additional system wear
  - Evaluated the Sensitivity of the Top Hardware Failure Likelihoods on the EPU Delta CDF

Risk Evaluation - Method

- Operator Response Times / HRA
  - PCTRAN analyses to determine available action times
  - Higher decay heat reduced operator action times
  - Most important impacts are:
    - Reduction in Time to Recover from a Loss of Shutdown Cooling during Reduced Inventory
    - Reduction in Time to Recover from a Loss of Decay Heat Removal during a Loss of Off-site Power
    - Reduction in Time to Recover the TD AFW Pump during a Control Room Complex Fire

Risk Evaluation - Results

Sample Human Action	Description	Base Time (Min)	EPU Time (Min)	Reduction in Time Available	SG Water Level at Trip (% NRWL)
AFHFDTDAFW	OP Fails to Manually Open Steam Valves to TDAFW Pump (No Fire)	25	17	31%	17%
RCHFPX1BAF	OP Fails to Align BAF given a Single PORV and No Charging Pumps	32	15	53%	17%
RCHFPX4BAF	OP Fails to Align BAF given Both PORVs Open	42	28	33%	17%
RCHFPX3BAF	OP Fails to Align BAF given a Single PORV and 75gpm Charging Flow	46	25	46%	17%
AFHFDSTART	OP Fails to Manually Start MDAFW Pump with No Auto Start Signal	84	65	23%	17%

From EPU Submittal: Table 2.13-12

Risk Evaluation - Results

Model	Pre-Uprate		Post-Uprate		Change	
	CDF	LERF	CDF	LERF	CDF	LERF
Internal	1.30E-05	1.27E-06	1.51E-05	1.51E-06	16%	19%
Internal Flood	1.17E-05	5.10E-07	1.23E-05	5.45E-07	5%	7%
Fire	2.83E-05	2.76E-06	3.07E-05	2.89E-06	8%	5%
Shutdown	1.07E-05	3.46E-07	1.30E-05	4.04E-07	21%	17%
Total	6.36E-05	4.88E-06	7.12E-05	5.35E-06	12%	10%

From EPU Submittal: Table 2.13-20

Risk Evaluation - Results

Case	Pre or Post Uprate	CDF	LERF	Optimize SI Pump in Fire	Limit RHR AOVs	Back-Up Air to Charging
Base	Pre	6.36E-05	4.88E-06	No	No	No
Base	Post	7.12E-05	5.35E-06	No	No	No
SI	Post	6.40E-05	4.73E-06	Yes	No	No
SDAOV	Post	6.59E-05	5.32E-06	No	Yes	No
BK-IA-CHG	Post	7.10E-05	5.20E-06	No	No	Yes
SI-AOV-IC	Post	5.85E-05	4.56E-06	Yes	Yes	Yes

From EPU Submittal: Table 2.13-21

C01

Risk Evaluation - Conclusions

The Plant Risk Level Pre-EPU without the modifications is higher than the Risk Level Post-EPU with modifications

Joe Pacher
System Engineering Director
Electrical Impacts

Electrical Impacts - Agenda

- Power Delivery
- Grid Impacts

Ginna Extended Power Uprate

Electrical Impacts – Power Delivery

- Electrical equipment continuous ratings verified
- Main transformer upgrades required
  - High-side bushings replaced
  - Additional cooling bank
- Main Generator Upgrades
  - Condensate cooler capacity increase
  - Installed additional condition monitoring equipment

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Electrical Impacts – Power Delivery

- Iso-phase Bus Duct Modification
  - Added third cooling fan
  - Increased motor ratings of existing fans
  - Additional temperature monitoring/inspections
- Oil Static Pipe Cables To Switchyard
  - Operate in oil recirculation mod
  - Additional monitoring installed

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Electrical Impacts – Grid

- Main generator can provide required reactive load to grid
- Grid can withstand Ginna trip from worst EPU conditions
- Operating limits on grid voltage and reactive load established to protect post-trip voltage on Ginna busses
  - Non-Uprate Reliability Enhancements
    - Circuit 751 Relocation/Upgrade
    - On-line contingency monitor being installed
- Four-hour station blackout coping capability is unaffected
    - No additional significant DC system loads due to uprate.
    - Battery capacity previously increased from 1200 to 1495 Amp-hrs for margin enhancement.

Jim Dunne
Project Lead Engineer
Mechanical Impacts

Mechanical Impacts - Agenda

- Steam Generator Vibration
- BOP Heat Exchanger Vibration
- Vibration Monitoring Program
- Flow Accelerated Corrosion
- Decay Heat Removal

Mechanical Impacts – Steam Generator Vibration

- Steam Generator - Vibration
  - Thermal-Hydraulic Analysis w/ATHOS
  - Vibration Potential in U-Bend & Tube Bundle Entrance
  - Fluidelastic Instability
  - Vortex Shedding (Tube Bundle Entrance)
  - Random Turbulence Excitation
  - Tube Wear (U-Bend Region)

Mechanical Impacts – Steam Generator Separators

- Steam Generator Steam Separators
  - 85 Primary/Secondary Separator Modules
  - Primary Centrifugal Type Separator
  - Secondary Centrifugal/ Cyclone Type Separator
  - Minimal Cross- Flow Velocities
  - Rigid Separator Bundle
  - Full Scale Testing of Separator Modules
  - Up-rate Flow Bounded by Tested Flow Conditions

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Mechanical Impacts - Vibration

- BOP Heat Exchangers - Vibration
  - Feedwater Heaters
  - Moisture Separator Reheaters
  - Condenser Tubing
- Vibration Monitoring Program
  - Pre-EPU Walkdown @ Full Power
  - Post EPU Walkdown (Pre- and Post-Full Power Levels)
  - Review Industry Operating Experience
  - Rotating Machinery Baseline

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Mechanical Impacts – Flow Accelerated Corrosion

- Flow Accelerated Corrosion (FAC)
  - Power Uprate effects evaluated using CHECWORKS
  - No component replacements required
  - Post Uprate Outage inspection sampling increased based on EPU conditions
  - Piping systems impacted will continue to be monitored to detect any deviation from predicted wear rates

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Mechanical Impacts – Cooling Systems

- SI and CS capable of removing accident heat load – no modification
- Preferred AFW flow adequate at 200 gpm/SG – no modification
- Standby AFW flow increased from 200 gpm to 235 gpm with discharge valve modification

Mechanical Impacts – Cooling Systems

- RHR capable of cooldown in required time for normal and accident conditions – no modification
- Component Cooling Water flow is adequate – no modification
- Service Water (from Lake Ontario) flow is adequate – no modification
- Spent Fuel Pool cooling – time to full core off-load will increase depending on lake temperature

Roy Gillow
Operations Lead
Operations and Testing

Operations and Testing - Agenda

- Human Factors
- Training
- Test Plan
- Large Transient Tests

Operations and Testing – Human Factors – App. R

- Increase in decay heat reduces available Appendix R response time for restoring AFW
- Reduction in post-trip pressurizer level reduces available Appendix R response time for restoring charging
- Necessary Appendix R response times reduced with plant modifications and procedure enhancements
- Plant modifications include charging and TDAFW local control and charging backup air for speed control
- Procedure enhancements include incorporation of modifications, change in priorities and streamlining

Operations and Testing – Human Factors – EOP/AP

- Revised FR-H.1 to ensure adequate SAFW flow in HELB
- Revised LOCA EOP to enhance boron precipitation guidance
- Revised procedures to reflect parameter, setpoint and alarm response changes

Operations and Testing – Training

- Classroom and Simulator Focus Areas
  - License Amendments (FIV, RAOC) and UFSAR Chapter 15
  - Control systems: Tavg, pzr level, steam dump, heater drains
  - BOP systems: condensate, feedwater, turbine
  - Appendix R procedures
  - Startup/shutdown and escalation testing
  - Abnormal and Emergency Procedures

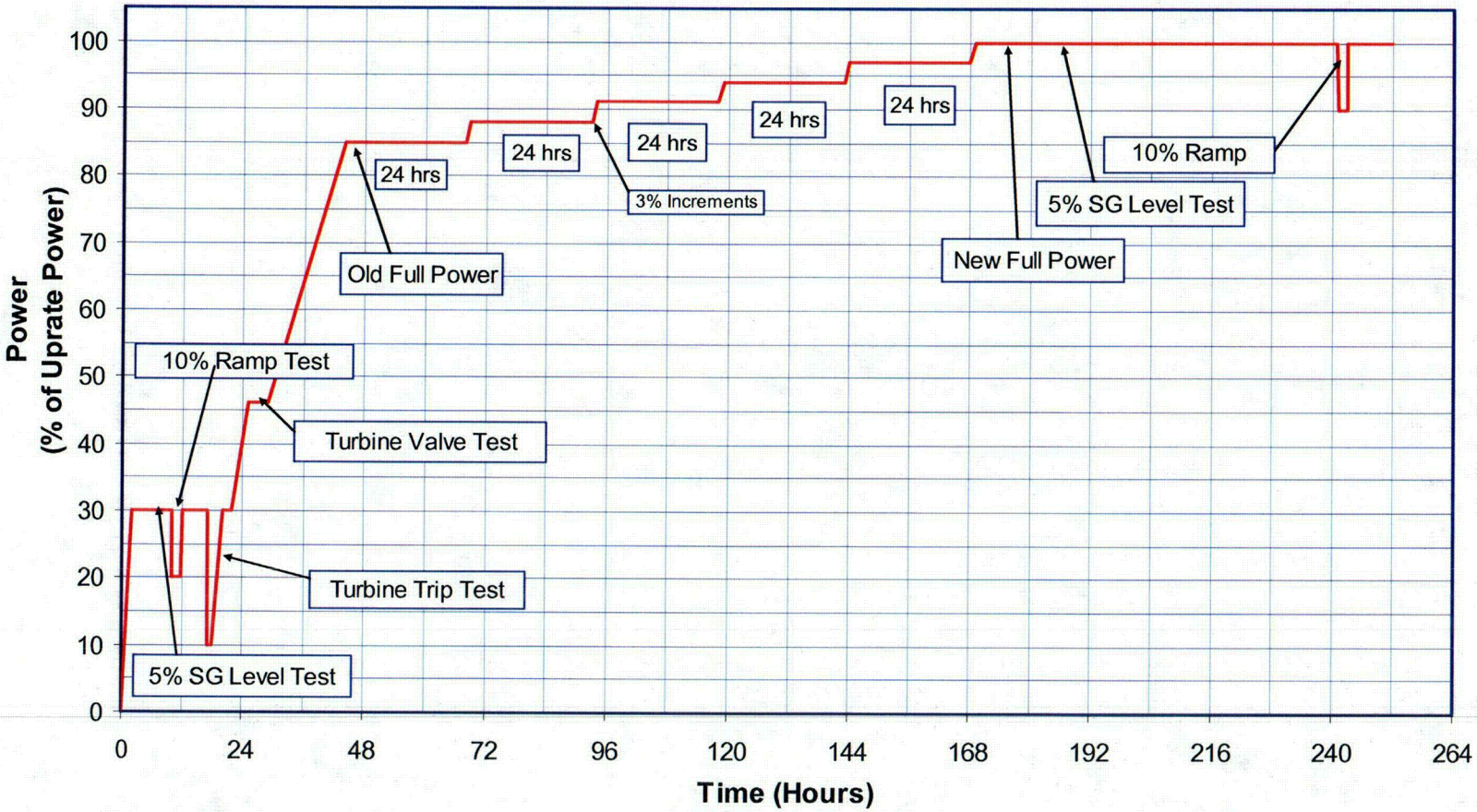
Operations and Testing – Test Plan

- Post modification tests
- Low power physics tests
- Steady state data review
- Transient tests
- Vibration monitoring
- 100% data review and surveys

Operations and Testing – Transient Tests

- Most benign tests run first:
  - +/-5% steam generator level demand at 30% and 100%
  - +/-10% power ramp at 30% and 100%
- Turbine manual trip at 30%
- Turbine control valve stroke at 46%

Operations and Testing – Power Escalation Test Plan



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Ginna Extended Power Uprate

Operations and Testing – Full Power Trip Test Unnecessary

- Full power turbine trip will cause reactor trip by design
- 30% turbine trip will have greater power mismatch and exercise rod control, steam dump control and pressurizer level control
- Proposed transient tests should identify system integration issues
- LOFTRAN code well benchmarked
- Industry experience good: events match simulation

Mark Flaherty
Vice President – Nuclear Technical Services (Acting)
Conclusion

Concluding Remarks

- Detailed and comprehensive reviews have been completed
- No safety issues were uncovered
- Comprehensive testing will be performed
- Ginna safety and reliability will be maintained through plant modifications, procedure changes and training

Table 2.8.5.0-1 Non-LOCA Analysis Limits and Analysis Results				
UFSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
15.1.1	Decrease in Feedwater Temperature	(1)	N/A	N/A
15.1.2	Increase in Feedwater Flow	Minimum DNBR (RTDP, WRB-1) (HFP) Minimum DNBR (STDP, W-3) (HZP)	1.38 (HFP) 1.613 (HZP)	1.60 (HFP) (2) (HZP)
15.1.3	Excessive Load Increase	Minimum DNBR (RTDP, WRB-1)	1.38	> 1.38
15.1.4	Inadvertent Opening of a Steam Generator Relief/Safety Valve	Bounded by Steam Line Break (UFSAR, section 15.1.5)	N/A	N/A
15.1.5	Steam System Piping Failure – Zero Power (Core response only)	Minimum DNBR (non-RTDP, W-3)	1.566	2.58
	Steam System Piping Failure – Full Power (Core response only)	Minimum DNBR (RTDP, WRB-1 correlation) (typical/thimble)	1.38/1.38 (422V+)	1.392/1.395 (422V+)
		Peak Linear Heat Generation (kW/ft)	22.7(3)	22.67
15.1.6	Combined Steam Generator ARV and Feedwater Control Valve Failures	Minimum DNBR (RTDP, WRB-1)	1.38	1.52
15.2.1	Steam Pressure Regulator Malfunction or Failure that Results in Decreasing Steam Flow	Bounded by Loss-of-External-Electrical Load (UFSAR, section 15.2.2)	N/A	N/A
15.2.2	Loss-of-External-Electrical Load	Minimum DNBR (RTDP, WRB-1)	1.38	1.61
		Peak RCS Pressure, psia	2748.5	2746.8
		Peak MSS Pressure, psia	1208.5	1208.0

Table 2.8.5.0-1 (cont.) Non-LOCA Analysis Limits and Analysis Results				
UFSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
15.2.3	Turbine Trip	Bounded by Loss-of-External-Electrical Load (UFSAR, section 15.2.2)	N/A	N/A
15.2.4	Loss-of-Condenser Vacuum	Bounded by Loss-of-External-Electrical Load (UFSAR, section 15.2.2)	N/A	N/A
15.2.5	Loss-of-Offsite-AC-Power to the Station Auxiliaries	Maximum pressurizer mixture volume, ft^3	800	635
15.2.6	Loss-of-Normal Feedwater	Maximum Pressurizer Mixture Volume, ft^3	800	537
15.2.7	Feedwater System Pipe Breaks	Margin to Hot Leg Saturation, °F	0.0	2
15.3.1	Flow Coastdown Accident – PLOF[4]	Minimum DNBR (RTDP, WRB-1) (typical/thimble)	1.38/1.38 (422V+)	1.601/1.597 (422V+)
	Flow Coastdown Accident – CLOF[5]	Minimum DNBR (RTDP, WRB-1) (typical/thimble)	1.38/1.38 (422V+)	1.489/1.491 (422V+)
	Flow Coastdown Accident – UF[6]	Minimum DNBR (RTDP, WRB-1) (typical/thimble)	1.38/1.38 (422V+)	1.385/1.392 (422V+)
15.3.2	Locked Rotor Accident	Peak RCS Pressure, psia	2997	2782
		Peak Cladding Temperature, °F	2700	1924.6 (422V+)
		Maximum Zirc-Water Reaction, %	16	0.53 (422V+)

Table 2.8.5.0-1 (cont.) Non-LOCA Analysis Limits and Analysis Results				
UFSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
15.4.1	Uncontrolled RCCA Withdrawal from a Subcritical Condition	Minimum DNBR Below First Mixing Vane Grid (non-RTDP, W-3 correlation) (typical/thimble)	1.447/1.447 (422V+)	1.987/2.238 (422V+)
		Minimum DNBR Above First Mixing Vane Grid (non-RTDP, WRB-1 correlation) (typical/thimble)	1.302/1.302 (422V+)	1.957/1.951 (422V+)
		Maximum Fuel Centerline Temperature, °F	4800[7]	2108 (422V+)
15.4.2	Uncontrolled RCCA Withdrawal at Power	Minimum DNBR (RTDP, WRB-1)	1.38	1.384
		Peak RCS Pressure, psia	2748.5	2748.1
		Peak MSS Pressure, psia	1208.5	1207.7
15.4.3	Startup of an Inactive Reactor Coolant Loop, (RCL)	No Analysis Performed (See Section Licensing Report 2.8.5.4.4)	N/A	N/A
15.4.4	Chemical and Volume Control System (CVCS) Malfunction (Boron Dilution)	Minimum Time to Loss of Shutdown Margin, Minutes	15	30.3 (Mode 1 manual)
			15	33.3 (Mode 1 auto)
			15	25.1 (Mode 2)
			30	32.0 (Mode 6)

Table 2.8.5.0-1 (cont.) Non-LOCA Analysis Limits and Analysis Results				
UFSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
15.4.5	Rupture of a Control Rod Drive Mechanism (CRDM) Housing (RCCA Ejection)	Maximum Fuel Pellet Average Enthalpy, cal/g	200	151.8 (BOC-HZP) 177.9 (BOC-HFP) 155.1 (EOC-HZP) 177.2 (EOC-HFP)
		Maximum Fuel Melt, %	10	0.00 (BOC-HZP)(8) 6.62 (BOC-HFP)(8) 0.00 (EOC-HZP)(9) 9.00 (EOC-HFP)(9)
		Peak RCS Pressure, psia	Generically addressed in Reference 15	
15.4.6	RCCA Drop	Minimum DNBR (RTDP, WRB-1)	1.38	> 1.38
		Peak Linear Heat Generation (kW/ft)	22.7(3)	< 22.7
		Peak Uniform Cladding Strain (%)	1.0	< 1.0
15.6.1	Inadvertent Opening of a Pressurizer Safety or Relief Valve	Minimum DNBR (WRB-1)	1.38	1.49
15.8	ATWS	Peak RCS Pressure, psig	3200	3,193

Table 2.8.5.0-1 (cont.)
Non-LOCA Analysis Limits and Analysis Results

UFSAR Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case

Notes:
1. Event bounded by the steam system piping failure at full power event. See LR section 2.8.5.1.1.
2. Bounded by zero power steam line break.
3. Corresponds to a UO_2 fuel melting temperature of 4700°F.
4. PLOF ≡ partial loss of flow (one-loop flow coastdown).
5. CLOF ≡ complete loss of flow (two-loop flow coastdown).
6. UF ≡ underfrequency (frequency decay of RCP power supply)
7. UO_2 fuel melting temperature corresponding to a burnup of ~48,276 MWd/MTU.
8. Fuel melting temperature = 4900°F
9. Fuel melting temperature = 4800°F