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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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POWER UPRATES SUBCOMMITTEE

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OPEN SESSION

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THURSDAY

APRIL 26, 2012

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 8:30 a.m., Sanjoy Banerjee, Chairman, presiding.

COMMITTEE MEMBERS PRESENT:

SANJOY BANERJEE, Chairman

SAID ABDEL-KHALIK

J. SAM ARMIJO

DENNIS C. BLEY

HAROLD B. RAY

JOY REMPE
MICHAEL T. RYAN
STEPHEN P. SCHULTZ
WILLIAM J. SHACK
GORDON R. SKILLMAN

CONSULTANTS TO THE SUBCOMMITTEE PRESENT:
MARIO V. BONACA
THOMAS DOWNER (via telephone)
GRAHAM B. WALLIS

NRC STAFF PRESENT:
WEIDONG WANG, Designated Federal Official
ALLEN HOWE
TRACY ORF
JENNIFER GALL
SAM MIRANDA
BEN PARKS
JOHN PARILLO

ALSO PRESENT:

STEVE HALE

RICH ANDERSON

RUDY GIL

JACK HOFFMAN

JAY KABADI

TODD HORTON

DAVE BROWN

STEVE FLUIT

LIZ ABBOTT*

CHRIS WASIK

TIM LINDQUIST*

CHRIS ALLISON*

BERT DUNN*

CONTENTS

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

8:29 a.m.

CHAIR BANERJEE: The meeting will now come to order. Are the microphones and everything -- you can hear? All right. This is a meeting of the Power Uprates Subcommittee, a standing committee of the ACRS.

I'm Sanjoy Banerjee, the chairman of the subcommittee. The ACRS members in attendance are William Shack, Gordon Skillman, Sam Armijo, Stephen Schultz, Said Abdel-Khalik, Harold Ray and Joy Rempe. As well as Mike Ryan, sorry.

MEMBER RYAN: It's all right.

CHAIR BANERJEE: Our ACRS consultants, actually former ACRS chairman -- sorry, Graham Wallis and Mario Bonaca. Also, consultant Dr. Thomas Downer will be participating on the phone. So he will be on the phone.

MR. WANG: I believe he's on there now.

CONSULTANT DOWNER: I am, Sanjoy.

CHAIR BANERJEE: Thanks. Weidong Wang of the ACRS staff is the Designated Federal Official for this meeting.

In this meeting the subcommittee will review St. Lucie 1 License Amendment Request for

Extended Power Uprate. We will hear presentations from the NRC staff and the representatives from the applicant Florida Power & Light Company.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

For the agenda items on safety analyses and thermal conductivity degradation issues the presentation will be closed in order to discuss information that is proprietary to the applicants and its contractors pursuant to 5 U.S.C. 552.b.C.4.

Attendance at this portion of the meeting dealing with such information will be limited to the NRC staff and its consultants, Florida Power & Light Company, and those individuals and organizations who have entered into an appropriate confidentiality agreement with them. Consequently, we need to confirm that we have only eligible observers and participants in the room for the closed portion.

The subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions as appropriate for deliberation by the full committee. The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register.

A transcript of the meeting is being kept and will be made available as stated in the Federal Register notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee. The participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard.

We will now proceed with the meeting and I'll turn it over to Alan Howe of NRR to take it forward.

MR. HOWE: Thank you and good morning. I'm Alan Howe, Deputy Director, Division of Operator Reactor Licensing in the Office of Nuclear Reactor Regulation.

I appreciate the opportunity to open the staff's presentation for the St. Lucie Extended Power Uprate to the ACRS Power Uprates Subcommittee this morning. Later the NRC staff will discuss the results of our safety and technical review of the licensee's application.

Our review was supported by pre-application meetings and public meetings, audits and several conference calls with the licensee. Through these numerous interactions with the licensee technical concerns were identified and resolved in a timely manner.

Some of the more challenging review areas that you'll hear about today include safety analyses of inadvertent opening of a PORV, inadvertent ECCS and CVCS actuation, feedwater line break, control element assembly withdrawal of power, and boron precipitation.

And like the emerging issue regarding fuel thermal conductivity underprediction that may affect the best estimate upper tolerance limit of peak cladding temperature for PWR large-break LOCA accidents, licensee will provide information on how this issue impacted the ECCS evaluation for the St. Lucie EPU and its resolution for this issue. The staff will also be available to address any questions.

A draft Safety Evaluation was provided to the ACRS on March 30th. Overall, I'm pleased with the depth and the breadth of the staff's review. In evaluating this Extended Power Uprate Application the staff addressed a diverse set of technical issues which required extensive interaction with the licensee.

We'd also like to thank the ACRS staff who assisted us in the preparations for this meeting, especially Weidong Wang. Thank you.

MR. WANG: Thank you.

MR. HOWE: At this point I'll turn over the discussion to our NRR project manager, Tracy Orf, who will introduce the discussion. Tracy?

MR. ORF: Thank you. Good morning. My name is Tracy Orf and I am the NRR project manager assigned to St. Lucie. Today we will hear presentations from Florida Power & Light and the NRC staff. The objective of that presentation is to provide you sufficient information related to the details of the EPU application and the evaluation supporting the staff's reasonable-assurance determination that the health and safety of the public will not be endangered by operation of proposed EPU.

Before I continue with the discussion of today's agenda I would like to present some background information related to the staff's review of the St. Lucie Unit 1 EPU.

On November 22nd, 2010, the licensee submitted its license amendment request for the St. Lucie Unit 1 EPU. The proposed amendment will increase the unit's licensed power level from 2,700 megawatts thermal to 3,200 -- 3,020 megawatts thermal. This presents a net increase in licensed core thermal power of 12 percent, including a 10 percent power uprate and a 1.7 percent measurement uncertainty recapture. This is an 18 percent increase from the original licensed thermal power.

The staff's method of review was based on Review Standard RS-001 which is the NRC's review plan for EPUs. As you know, it provides a Safety Evaluation template as well as matrices that cover the multiple technical areas that the staff reviews.

CHAIR BANERJEE: Tracy, remind me because I don't remember, but have we reviewed a power uprate of this magnitude for Combustion a few years ago, or is this the first? I don't know.

MR. ORF: I don't have that history.

MR. HOWE: I don't have the statistics but we'll track that down and try to bring that back to you later today.

CHAIR BANERJEE: Okay.

MR. ORF: There are no associated --

MR. HALE: If I could, this is Steve Hale, Florida Power & Light. No, there have not been an uprate of that magnitude for CE NSSS.

CHAIR BANERJEE: Thanks, Steve.

MR. ORF: There were no associated or linked licensing actions associated with this EPU application. There were numerous supplements to the application responding to multiple staff RAIs. There were approximately 85 supplemental responses that supported our draft Safety Evaluation. Also, the staff completed several audits to complete its review and resolve open items.

This slide lists the topics for today's discussion. FPL will begin by providing an overview of the EPU and then present materials on steam generator. FPL and the NRC staff then will each make their presentations on fuel and core and safety analyses. The NRC staff will then present on dose analysis.

At the conclusion of the meeting, as needed, we can discuss any additional questions in preparation for a full committee meeting.

As mentioned before, there will be closed portions of this meeting during the afternoon session and those portions are scheduled to begin at around 2:15 p.m. If there is any proprietary information that needs to be discussed it can be deferred to the designated closed session.

This concludes my presentation as far as the introduction. Unless there are any questions I would like to turn over the presentation to Mr. Rich

Anderson and FP&L. Mr. Rich Anderson is the site vice president for the St. Lucie Nuclear Power Plant.

MR. ANDERSON: Good morning. My name is Rich Anderson. I'm the site vice president for St. Lucie Station. I want to thank the subcommittee for the opportunity to speak on behalf of Florida Power & Light for the St. Lucie Unit 1 Extended Power Uprate and the information we're providing to you.

Here today to share information about St. Lucie Extended Power Uprate are Jack Hoffman, licensing manager for the Extended Power Uprate, Chris Wasik, licensing manager, and Jay Kabadi, manager of Nuclear Fuels Group for St. Lucie.

This is a significant undertaking that will not only increase the output of the plant but will provide equivalent upgrades to improve the plant availability and reliability for a long-term, safe, reliable operation. Jack Hoffman will discuss some of these changes later.

The St. Lucie site is located on Hutchinson Island southeast of Fort Pierce, Florida, and is a primary electrical generation source for St. Lucie County. It is a Combustion Engineering pressurized water reactor nuclear steam supply system. We have a Westinghouse turbine generator with one high-pressure and two low-pressure turbines. The original architectural engineer was Ebasco and our nuclear fuel supplier is AREVA. The current output of the station is approximately 950 megawatts-electric gross.

With respect to some of the key milestones and major equipment replacements for St. Lucie Unit 1 the original operating license was issued in 1976. Due to corrosion issues steam generators were replaced in 1998 with B&W series 67 steam generators. In 2003 a renewed operating license was issued for Unit 1 extending the operation of the unit until 2036. Also in 2003 a new single-failure-proof crane was installed to support our dry fuel storage operations.

During the 2005 refueling outage the reactor vessel, head and pressurizer were replaced to address Alloy 600 issues. And finally, we have begun long-term equipment reliability plans which include replacements of the reactor coolant pump motors to be completed by 2015.

MEMBER SKILLMAN: Rich, before changing may I ask you a question, please?

MR. ANDERSON: Certainly.

MEMBER SKILLMAN: Those steam generators have now been in service for approximately 15 years.

What is their status in terms of plugging and overall material condition, please?

MR. ANDERSON: Steve or Rudy?

MR. HALE: Hi, this is Steve Hale, Florida Power & Light. Yes, Mr. Skillman, we'll be covering the steam generator performance as a separate topic. Rudy Gil will go over that. But just to let you know we have approximately 15 tubes plugged in the two steam generators since they began operation in `98. And I don't think we've plugged a tube in the last two cycles, so the performance has been excellent.

MEMBER SKILLMAN: Thank you. One more question on hardware, please. You changed two reactor coolant pump motors. Why?

MR. ANDERSON: As part of the long-term motor plan across the site we have spaced out the large capital replacements of not only reactor coolant pump motors, but other large motors. We do have predictive monitoring programs. They have shown that for the long-term reliability and the extended operating license these motors will need to be replaced and refurbished through that period.

MEMBER SKILLMAN: Rich, thank you. Steve, thank you.

CHAIR BANERJEE: It was not to try to also get a little more flow? Or that had nothing to do with it?

MR. ANDERSON: No.

CHAIR BANERJEE: You are getting more flow in the uprate.

MR. KABADI: I think the more flow is actually only in the analysis. Our an actual flow is more than 410,000 right now. We are just increasing the flow in the analysis portion, but we are not replacing the actual flow in the plant.

CHAIR BANERJEE: I see. So the actual flow is higher than --

MR. KABADI: Yes.

CHAIR BANERJEE: -- in the original analysis.

MR. KABADI: Yes. When we measured flow the last two cycles we have been measuring 410 approximately.

CHAIR BANERJEE: Okay.

MR. HOFFMAN: Most replacements are like for like.

MEMBER REMPE: While we are discussing the steam generators, that's considerably different than the performance of the Unit 2 replacement steam generators, correct?

MR. ANDERSON: Yes, it is.

MEMBER REMPE: And could you share any insights either now or perhaps later this afternoon on why there's such a difference?

MR. GIL: This is Rudy Gil with FPL. I can certainly cover that during my presentation on steam generators.

MEMBER REMPE: Great.

MR. GIL: So we can go over what some of those differences are.

MEMBER REMPE: Okay, thank you.

MR. ANDERSON: The original licensed power for Unit 1 was 2,560 megawatts thermal. An approximate 5 and a half percent stretch power uprate was implemented in 1981 increasing the licensed core output level to 2,700 megawatts thermal. This was accomplished with relatively few hardware modifications to the plant.

The Extended Power Uprate we are discussing today will increase the licensed core level power level of Unit 1 to 3,020 megawatts thermal. This represents approximately 100 megawatts electric of clean nuclear energy.

Are there any questions? Okay, this completes the topics that I intended to cover. Now

I'll turn it over to Jack Hoffman who will summarize the changes to the plant.

MR. HOFFMAN: Thank you.

CHAIR BANERJEE: Excuse me, sorry. You're doing both a MUR and an uprate together.

MR. ANDERSON: That is correct.

CHAIR BANERJEE: In this amendment. Okay.

MR. ANDERSON: Okay.

MR. HOFFMAN: Good morning. My name is Jack Hoffman and I'm the licensing manager for the St. Lucie Unit 1 Extended Power Uprate Project. As stated earlier, Florida Power & Light has submitted a license amendment request for an approximate 12 percent licensed core power increase for St. Lucie Unit 1. This proposed power increase consists of a 10 percent uprate from the current power level of 2,700 megawatts thermal to a power level of 2,970 megawatts thermal. In addition, the amendment request includes a 1.7 percent core power increase as a result of a measurement uncertainty recapture. Together, these power increases raise the licensed core power to 3,020 megawatts thermal.

One important aspect of the proposed uprate is the treatment of emergency cooling system pump net positive suction head, or NPSH. For the EPU pump NPSH was analyzed using classic analytical methods and sufficient NPSH margin exists at EPU conditions without taking credit for containment overpressure.

As part of the uprate project a grid system stability impact was performed to evaluate the impact of the EPU on the reliability of the electric power grid. The study was performed for the most limiting configuration of both St. Lucie units, that's Unit 1 and Unit 2, at the proposed EPU power levels. Results of the grid simulations indicate acceptable grid performance for the most extreme event. And final modifications to support operation of the St. Lucie Unit 1 EPU are being implemented in the year 2012.

As was mentioned previously by the NRC, the St. Lucie EPU license amendment request was developed using the guidance contained in RS-001. The St. Lucie EPU addressed lessons learned from previous pressurized water reactor EPU submittals, including Ginne, Beaver Valley, Comanche Peak, Point Beach and Turkey Point. Note that these last two PWR EPU licenses for Point Beach and Turkey Point are also part of the Florida Power & Light Nuclear Division. And our St. Lucie Unit 1 EPU project took direct advantage of those resources as part of this licensing effort.

In accordance with RS-001, the St. Lucie EPU analyses and evaluations were performed consistent with the St. Lucie current licensing basis. The impact of the EPU on license renewal was also evaluated in each license report section. These analyses and evaluations addressed system structures and components subject to new aging effects due to changes in their operating environment, system structures and components that had been added or modified to support operation at EPU conditions, and finally, the impact of the EPU on the license renewal time-limited aging analyses was performed and included as part of the application.

As I mentioned previously, the proposed uprate includes a measurement uncertainty recapture. This MUR submittal follows the guidance of NRC Regulatory Issue Summary, or RIS 2002-03. And the St. Lucie Unit 1 MUR methodology is essentially identical to the uprate recently approved for Turkey Point Units 3 and 4.

Comprehensive engineering analyses were performed on all affected primary side and secondary side system structures and components that are impacted by the proposed EPU. The analyses were performed at the most limiting EPU design conditions. The secondary side heat balances were developed assuming a bounding NSSS power level of 3,050 megawatts thermal which is consistent with the power level assumed in the EPU safety analyses.

Detailed hydraulic analyses were performed for the feedwater condensate and heater drain systems of this bounding NSSS power level. In addition, structural analyses of the feedwater condensate, heater drain and main steam systems were performed for EPU and the dynamic response to events such as fast valve closures was analyzed.

Also, an analytical model of the St. Lucie primary and secondary control system was developed for EPU. This model was used to evaluate the plant's response to EPU normal, off-normal and transient conditions. EPU control system changes are based on the model results.

The licensing process used by St. Lucie included a detailed review of operating experience for each license application section, including a review of other uprate license applications, the industry uprate RAI database, industry operating experience and INPO guidance.

MEMBER SKILLMAN: Jack, before you change, let me ask a question, please.

MR. HOFFMAN: Sure.

MEMBER SKILLMAN: In the balance of plant I noticed that the emergency feedwater inventory has been changed and increased significantly. I would ask where else on the secondary side has the uprate pushed the unit to its edge. For instance, you've retained the same feedwater pump motor.

MR. HOFFMAN: That's correct.

MEMBER SKILLMAN: You retained the same heater drain pump.

MR. HOFFMAN: That is correct.

MEMBER SKILLMAN: So it appears as though you had built-in capacity from original design.

MR. HOFFMAN: That is correct.

MEMBER SKILLMAN: But with the change that you are making in the power uprate where in the secondary system are you pushed closest to the edge?

MR. HOFFMAN: Actually, the limiting component for the extended power uprate for St. Lucie Unit 1 is the main generator. The main generator has been uprated to 1,200 MVA for the uprate and that's the maximum allowable rating that we can achieve with the existing frame of the generator.

MEMBER SKILLMAN: Did you change the rotor?

MR. HOFFMAN: We changed the rotor and we rewound the stator. And we increased hydrogen pressure.

MEMBER SKILLMAN: Got it. Thank you.

MR. HOFFMAN: And there were other things, including hydrogen coolers and quite a bit of modifications performed to the main generator.

MEMBER SKILLMAN: Will we talk about this later, or is it --

MR. HOFFMAN: Yes.

MEMBER SKILLMAN: We will?

MR. HOFFMAN: Briefly and we'll answer any questions you have.

MEMBER SKILLMAN: Thank you.

MR. HOFFMAN: Sure.

MEMBER RAY: Along the same line you referred to a model having been created to provide an integrated analysis of the plant in the uprate condition. It brings to mind the question, well, how critical is that model to the results that you have here and how is it qualified?

MR. HOFFMAN: Actually, the model that was used is the Combustion Engineering CENTS simulation model, and that's a very detailed model that includes both the primary system, the core, steam generators, the feedwater, condensate and main steam systems.

MEMBER RAY: So it wasn't created for this project?

MR. HOFFMAN: No sir, it's an approved code that Westinghouse -- that Combustion Engineering uses. And we also benchmarked that code. We did extensive benchmarking as part of the EPU process to five actual events at St. Lucie, plus we did benchmarking of the control system modifications to the CENTS model as part of the factory acceptance testing. So, quite rigorous.

MEMBER RAY: It sounded to me like you'd created this model and I --

MR. HOFFMAN: No.

MEMBER RAY: I misunderstood. Okay.

MR. HOFFMAN: All right. This table provides a comparison of the primary and secondary plant parameters for St. Lucie Unit 1.

As Rich Anderson noted, St. Lucie Unit 1 was originally licensed in 1976 at a core power level of 2,560 megawatts thermal. An approximate 5 and a half percent stretch power uprate was approved and implemented in 1981.

The proposed EPU consists of a 320 megawatt thermal core power increase above the current power level of 2,700 megawatts thermal. The thermal design flow is increased to 187,500 gallons per minute per reactor coolant system loop, and this flow increase provides additional EPU margin and response to postulated events. It's noted that the core bypass flow is also increased to 4.2 percent for the EPU.

The proposed EPU cold leg temperature is being increased by 2 degrees Fahrenheit to a value of 551 degrees Fahrenheit. This temperature increase results in an EPU-predicted steam generator pressure close to that experienced at today's power level.

A bounding hot leg temperature of 606 degrees Fahrenheit is predicted for the EPU. This EPU hot leg temperature is well below the industry experience for similar PWR uprates.

MEMBER SKILLMAN: Jack, just a nit.

MR. HOFFMAN: Yes.

MEMBER SKILLMAN: In the Safety Evaluation that number, T-hot, is identified as 608.2 and your chart shows 606. Small difference, but words matter. Is there something in that that we should be aware of?

MR. HOFFMAN: These values here come from what's known as the Performance Capability Working

Group Analysis performed by Westinghouse. And it's part of their approved methodology that they use consistently for EPUs. There was additional conservatism added as part of the Chapter 15 safety analyses that would predict temperatures that would be above that predicted by the PCWG code. Difference in analytical methods and conservatisms.

MEMBER SKILLMAN: Thank you.

MEMBER ABDEL-KHALIK: At the new power and reduced exit sub-cooling would this be considered a high-duty core?

MR. KABADI: No, this is still well below our other units operating.

MEMBER ABDEL-KHALIK: High-duty in terms of EPRI standards for CIPs.

MR. KABADI: No. Right now St. Lucie 1 has left a pretty much clean core. And as part of this we will be evaluating cycle by cycle by cycle. But right now steaming rates and these are below our other units which have industry experience. So we are not going outside the industry experience space. But we will follow that up as part of your inspections.

MEMBER ABDEL-KHALIK: But on that scale where does this core fall?

MR. KABADI: We still, for the first cycle we will still fill in the load. And we'll be measuring the crud levels and all that we operate every cycle. And we'll take right action and we'll put that out so we know our core design. And then that's why we'll reduce peaking in some cases. We will not increase our kilowatt per foot. And that's all to maintain steaming rates as low as possible. We'll be increasing compared to the current, but we still expect to be not going outside the industry experience base to go into the high-risk area.

MEMBER SKILLMAN: Okay, thank you.

CHAIR BANERJEE: So the power-to-volume ratio that you have which is around -- for the core reactor vessel is around 0.36 whereas for one of your other plants, some of your others plants it's below 0.3. So is 0.36 higher than industry experience or is it not?

MR. KABADI: The power ratio you are talking about --

CHAIR BANERJEE: Volume ratio.

MR. KABADI: This is based on the RCS volume you are talking about?

CHAIR BANERJEE: Yes. Checking the RCS volume, yes. Your RCS volume is 8,303 feet cubed and your power is going to be 3,029 megawatts thermal.

MR. KABADI: Yes, but when we look inside the vessel we are not going outside. Now, 8,303 feet cubed you are talking about is the complete RCS. Our total RCS volume even without pressurizer is actually in the range of about 10,000.

CHAIR BANERJEE: Well, then I have the wrong number here perhaps.

MR. KABADI: Our St. Lucie RCS volume including pressurizer goes in the range of about 11,000 cubic feet.

CHAIR BANERJEE: What is this 8,303 number then?

MR. WANG: That number basically -- I just searched the Safety Analysis Report -- I mean, the license amendment request, and I found it somewhere. It said RCS volume, maximum volume somewhere.

CHAIR BANERJEE: Anyway, let's clarify. In comparison to industry experience what is your power-to-volume ratio actually? You know, not our calculations but your calculations.

MR. KABADI: We have looked in terms of what happens in the core, like our RCS volume, RCS flow and all these -- flow to the power ratio is actually higher so that's why we don't get as high exit temperatures as some of the other units in our fleet. But we will look at what you said, total volume, because we have not used that as one of the parameters for any particular analysis.

CHAIR BANERJEE: Okay. So we'll come back to it.

MEMBER ARMIJO: Yes. As far as fuel duty, do you track a core power density kilowatts per liter for this upgraded core compared to the typical PWRs that are running at uprated power?

MR. KABADI: And one of the things you will see later is we have not increased our peak kilowatt per foot. Actually we are slightly reducing.

MEMBER ARMIJO: Spread it out.

MR. KABADI: Right. Exactly. So the power goes up, our peak kilowatt per foot limit actually, the way we designed, the limit will go down.

MEMBER ARMIJO: Okay.

MR. KABADI: That falls below even our other units. Like Turkey Point also, peak kilowatt per foot is higher than what St. Lucie.

CHAIR BANERJEE: But the fuel is different. This is 14 by 14, correct?

MR. KABADI: Yes.

CHAIR BANERJEE: What is your -- we'll come back to this, but undoubtedly you'll tell us what the stored energy is at some point, right?

MR. KABADI: Yes, I think that's one of the topics in the closed session.

CHAIR BANERJEE: Yes.

MR. KABADI: We will talk about that.

CHAIR BANERJEE: We can follow that up.

MEMBER REMPE: Before you leave this slide, I keep bringing in St. Lucie 2 but their current thermal design flow is like 116. In the documents that were submitted to us for an upcoming uprate has that the thermal design flow is 167.500 gallons per minute per loop and it's going through the EPU also to the same value. What's the difference? Why is the flow lower currently for Unit 2? Or is that a typo?

MR. HOFFMAN: I can take that. There's history. For example, Unit 1, if you go back to the original power level of 2,560 and see the thermal design flow of 185 that was actually maintained for the stretch power uprate.

However, over time because of the degradation of our steam generators and tube-plugging, the thermal design flow in the technical specifications was reduced. And even for St. Lucie Unit 1 it was reduced to a value of 145,000 gallons a minute years back.

New generators were put in, we recovered that flow margin and the current tech specs for St. Lucie Unit 1 increased that flow value back to 182500. And as Jay Kabadi mentioned, our actual measured flow per loop is approximately 205,000 gallons per minute. So we're taking advantage of that as part of the EPU project and margin in the safety analyses.

MEMBER REMPE: Okay. Thank you.

MR. HOFFMAN: Okay? Chris, if you could just go back to the slide. One additional thing I wanted to point out with the hot leg temperature again. We do note that it's 606 degrees and did extensive EPU analyses for the impact of this temperature on the existing Alloy 600 program. And we've concluded that the existing program is more than sufficient to manage the potential aging effects at EPU operating conditions.

MEMBER SKILLMAN: Jack, before changing please, why would there be core bypass percentage increase from 3.9 to 4.2?

MR. KABADI: Actually, there is no real physical change to this value. It was just to provide a little more flexibility in case in the future any minor change could occur. So actually the current bypass flow could have been retained. It just makes the analysis a little more conservative. We are not doing any physical change.

MEMBER SKILLMAN: Okay. Please confirm what I believe I just heard. I think you said that the measured core flow is over 200,000 gallons per minute. You are using as an uprate design flow 187,500. Is that accurate?

MR. HOFFMAN: That is correct, because that does maximize the hot leg temperature and that's what the appropriate analyses were based on. We expect the actual uprate hot leg temperature to be around 601.8 degrees.

MEMBER SKILLMAN: Because of a higher flow?

MR. HOFFMAN: Exactly.

MEMBER SKILLMAN: Now, hold that thought. What does that do to moderator temperature coefficient in some of the other nuclear parameters?

MR. KABADI: Yes, and I think I'll go a little bit over that, but our moderator temperature coefficient we didn't have to increase. Our current value is -32 and we are maintaining the same. And all the core designs we have done represented -- actual we can meet that without any major concern to increase that.

MEMBER SKILLMAN: Thank you.

MEMBER ABDEL-KHALIK: I believe you just indicated that the core bypass flow you simply increased from 3.9 to 4.2 percent to give you a little more flexibility. There is no change. How was that calculated? How was the original core bypass flow calculated?

MR. KABADI: I think in the original design all the bypass areas were evaluated from the delta P considerations and was calculated.

MEMBER ABDEL-KHALIK: Right.

MR. KABADI: According to that any changes were evaluated for deltas. Like for example, when we put the hafnium assemblies in some cycles, at that time the flow was slightly reduced because that provided some additional resistance to the flow. Then we removed that so it came back. So, our original value is actually, like Jack pointed out, was very close to 3.7. It didn't change much based on the fuel design. We made a fuel design change also going from original combustion fuel to AREVA fuel.

There were some minor, minor changes, but the actual calculation was done based on the original design and then we just calculated the --

MEMBER ABDEL-KHALIK: You're changing fuel?

MR. KABADI: Right. So that had just been -- first time was made when we moved from CE fuel to the AREVA fuel. And every time we did a fuel design change there was no major change to the bypass.

MEMBER ABDEL-KHALIK: So how do we know that this new sort of out-of-thin-air value 4.2 percent is consistent with the new fuel design?

MR. KABADI: No, we are not changing fuel design.

MEMBER ABDEL-KHALIK: So, again, where does 4.2 come from?

MR. KABADI: This is just an additional margin we put. If you do a fuel design change we will be evaluating based on the actual delta P calculations to see whether 4.2 is okay or not, and then we have to adjust accordingly. Right now we put it as the additional margin in the analysis so that all the V&V analysis are analyzed a little more than what they should be. So then if we do some changes and that does increase the bypass flow, and if it still falls below 4.2 then our analysis would be okay. But if it exceeds 4.2 then we have to redo the analysis.

MEMBER ABDEL-KHALIK: Okay. We'll talk

later I guess.

MEMBER SHACK: Just come back to your Alloy 600. Most of your remaining Alloy 600 is in cold leg locations. What's the temperatures on those things?

MR. HOFFMAN: For EPU?

MEMBER SHACK: Yes.

MR. HOFFMAN: As you can see from the slide, the current cold leg temperature is 549 degrees. T-cold. And we're increasing that. Actually, we run a little bit lower than that. We run about 548.5 and for EPU we're increasing that 2 degrees to 551.

MEMBER SHACK: And the hot leg locations are on this order of the 606?

MR. HOFFMAN: That's correct. That's a conservative number on the high side that we evaluated the impact to the Alloy 600 program.

MEMBER SHACK: And is there any mitigation on those hot leg locations?

MR. GIL: This is Rudy Gil. Yes, the -- what we have done with all of our hot leg locations is we have mitigated all of them. We've either implemented weld overlays, the mechanical stress improvement, or wherever it was feasible actually for the smaller locations we have actually replaced the weld and gone to all stainless steel. So obviously the larger ones that was not feasible so we've -- but we have mitigated all of our hot leg locations, including replacement of the pressurizer. Because that one had a significant number of heater sleeves, so when we evaluated the options that was actually the best way to address really the area with the most susceptibility to the Alloy 600 concerned.

MEMBER ABDEL-KHALIK: Now, with the actual measured core flow, what is going to stay constant, T-ave?

MR. HOFFMAN: T-cold.

MEMBER ABDEL-KHALIK: T-cold is going to stay constant.

MR. HOFFMAN: This is a Combustion Engineering designed plant and they operate based on a constant T-cold.

MEMBER ABDEL-KHALIK: Okay. Just for the desired steam pressure.

MR. HOFFMAN: Correct. Delta-t, T-ave. Correct.

MEMBER SKILLMAN: If you lose a reactor coolant pump, what do your analyses indicate and what do your procedures require?

MR. KABADI: This is Jay Kabadi. I think by tech specs we cannot operate with less than all four pumps operating. So we cannot operate with less than four pumps.

MEMBER SKILLMAN: How do you handle the reverse flow transient?

MR. KABADI: Our -- I think those will come into play only for fuel accidents and our pumps have anti-rotation device.

MEMBER SKILLMAN: How about the mechanical components in the reactor coolant system that are now saying T-hot versus T-cold?

MR. KABADI: You're asking in terms of structural analysis?

MEMBER SKILLMAN: You get flow reversal in one loop. If you lose the reactor coolant pump, how is that analyzed?

MR. KABADI: What I can say right now, and you can get more details, is our reactor internals did take into account all the flow conditions. But I think what flow exactly in the anti-reverse direction --

MEMBER SKILLMAN: I'm not really interested in the flow. I'm really interested in the transient reactor vessels and the nozzles. We can talk about that later.

MR. KABADI: Right, yes.

MR. HORTON: Excuse me, this is Todd Horton, FPL. I do oversee the operating crews. I don't know if it was clear in the communication, but on the loss of the one reactor coolant pump there is a reactor protection system automatic trip associated with that. And that would mitigate the transient at that point.

MEMBER SKILLMAN: You certainly have reverse flow.

MR. HORTON: That is correct.

MEMBER SKILLMAN: And you do have a thermal transient that accompanies that reverse flow. And I'm curious if that's --

MR. HORTON: I just wanted to clarify that point.

MEMBER SKILLMAN: Yes. Got it. Let's come back to this. I'd like to know that that transient is --

MR. KABADI: Understood. I think from the structural point of view I'd like to know how that is handled. But from the safety analysis point of view, as Todd mentioned, the reactor trip and the safety analysis to take into account, but your concern mainly is to see how it's handled in terms of reactor internals and the flow reversal takes place.

MEMBER SKILLMAN: Delta P versus time on the loop that's gone idle, yes. Thank you.

MR. HOFFMAN: Okay, next slide. There have been several EPU modifications as shown on this slide that have a beneficial safety impact.

The first modification I'd like to point out is an increase in the safety injection tank design pressure. This change allows St. Lucie Unit 1 to increase the technical specification safety injection tank operating pressure. This change has a positive impact on the EPU safety analyses and in particular the small break LOCA event.

The next modification I'd like to discuss adds the capability for remote purging of the containment atmosphere to accommodate a reduction in the maximum initial containment pressure allowed by plant technical specifications. This change again provides a margin benefit to the EPU loss-of-coolant accident and main steam line break containment pressure in temperature analyses.

The last modification I'd like to point out is at the bottom of the slide. That's where for EPU we are raising our reactor protection system, steam generator low low-level trip setpoint, not because of safety analysis reasons. All of our Chapter 15 safety analyses are performed using the current low-level steam generator trip setpoint. However, as part of EPU, our probabilistic risk assessment identified that some risk improvements could be made by changing this trip setpoint and increasing the time that the operators have to make decisions for once-through cooling upon a total loss of feedwater, you know, beyond design basis type event. Okay.

For the balance of the plant a number of changes are being implemented in the steam path. In particular, both the high-pressure and low-pressure steam paths are being replaced by EPU and a modernized turbine control system is also being implemented to replace the existing obsolete system.

MEMBER ABDEL-KHALIK: I'm sorry. Back to the previous slide.

MR. HOFFMAN: Sure.

MEMBER ABDEL-KHALIK: The last point you made. This is the low low level in the steam generator?

MR. HOFFMAN: Yes. That is correct.

MEMBER ABDEL-KHALIK: Right. And would

this be the first trip signal that would trip you on a loss-of-feedwater event?

MR. HOFFMAN: Yes.

MEMBER ABDEL-KHALIK: It is?

MR. HOFFMAN: Yes.

MEMBER ABDEL-KHALIK: And is it the same first trip signal that would trip you on a steam line break?

MR. KABADI: This is Jay Kabadi, Florida Power & Light. For a steam line break typically we trip on low pressure.

MEMBER ABDEL-KHALIK: Low pressure on the primary side.

MR. KABADI: On the --

MEMBER ABDEL-KHALIK: Secondary side?

MR. KABADI: We have both the trips, primary side and secondary side, for the limiting events. It depends on the -- we analyze steam line break two different ways. One is we call pre-scram event and one is a post-scram event.

MEMBER ABDEL-KHALIK: But back to the loss of feedwater. Are you supposed to take credit for the very first trip signal, or are you assumed to -- are you required to assume that the second trip signal is what is going to trip you?

MR. KABADI: No, there is no requirement to skip that. We do take credit for the first trip for the loss of normal feed which is the low-level trip.

MEMBER ABDEL-KHALIK: Thank you.

MEMBER SKILLMAN: The third bullet from the bottom, the EQ radiation shielding.

MR. HOFFMAN: Yes.

MEMBER SKILLMAN: Is this unique for the power uprate, or is this a catchup for EQ?

MR. HOFFMAN: This is unique. The dose analyses performed or the actual radiological analyses performed for EPU for inside containment, we did bump up the amount of radiation for the containment atmosphere. And this particular modification involves the two dampers with our shield-building ventilation system. So it deals with the actual increase in the dose of the containment atmosphere.

And these components that we actually are shielding two dampers in that ventilation system were close to exceeding the EQ threshold pre-EPU, and with the EPU -- and the EPU dose assumptions that we made they bumped over the limit so we made the decision to shield them strictly for EPU.

MEMBER SKILLMAN: Thank you.

MEMBER SCHULTZ: What drove the modification in the spent fuel pool with respect to the addition of neutron absorption to the racks, and how extensive was that?

MR. KABADI: Yes, that's the major change in terms of criticality. We did the criticality analysis for two reasons. One is we are slightly increasing the enrichments of the fuel, not much, but our current limit is 4.5 and we are changing it to 4.6 just to have more flexibility.

And secondly, we are trying to meet our new analysis, meet the new standards. Our old analysis had -- some of the assumptions within the current standards of the industry with the staff issues raised plus even other concerns, new data available, we had to make a lot of additional changes to the analysis which goes in the non-conservative directions compared to the old. So we had to put new observers inside racks and those are the available observers we are put in which is called Metamic.

MEMBER SCHULTZ: Thank you.

MR. HOFFMAN: Okay, in addition to the steam path modifications that I discussed the main feedwater pumps are also being replaced as part of the EPU project. And as noted earlier the break horsepower requirements for the new pumps are within the horsepower ratings of the existing motors. So the existing motors will be retained for EPU.

We've also made modifications to the main feedwater regulating valves and the valve actuators, and we've also replaced the number 5 high-pressure feedwater heater as a result of increases in the extraction steam pressure being realized at EPU.

MEMBER SKILLMAN: Quick question. You're changing the electrohydraulic control system. Is that a complete replacement of the front standard, or is that just a box that has a bunch of wires that's connected to the front standard?

MR. HOFFMAN: It is a complete replacement. We've gotten rid of the old mechanical overspeed trip devices on the front standard and we've upgraded to the new Westinghouse Ovation design. That's the system that's been approved for the AP1000 units. It's also used at Byron and Braidwood and also several fossil applications. But it's state of the art, fault-tolerant, redundant, diverse, much more reliable and does provide us some benefits and probability space with respect to missile analysis. So I consider it a good modification for the power plant because it's getting rid of some obsolete equipment that we've had trouble with over the years.

MEMBER SKILLMAN: Okay, thank you. Thank you.

CHAIR BANERJEE: What upgrades did you do on the main condenser?

MR. HOFFMAN: The main condenser modifications are really minimal. We did extensive analyses of the main condenser and they were more than adequate to meet the uprate conditions. We did extensive walkdowns with subject matter experts of the internals of the condenser as part of that evaluation.

The modifications for EPU are pretty straightforward. We're adding additional tube stakes for tube vibration and we've also made some improvements to the air ejection or air removal system that's been problematic over the years.

CHAIR BANERJEE: So it will be handling a higher heat load, clearly.

MR. HOFFMAN: Correct.

CHAIR BANERJEE: And what you found was the original condenser had sufficient --

MR. HOFFMAN: That's correct.

CHAIR BANERJEE: -- over-design for you to handle that.

MR. HOFFMAN: That's correct. Obviously

the delta T across the tube bundle is increased, but within our limits, environmental limits that we've maintained with the state.

CHAIR BANERJEE: Is there any shared services with Unit 2 on this?

MR. HOFFMAN: From a safety-related point of view, no. Although we do have a cross-tie between the Unit 1 and the Unit 2 condensate storage tanks that's there as a part of the original missile criteria differences between the units. So that's a normally isolated feature that was added as part of the license for Unit 2 so that Unit 2 could provide additional condensate storage tank inventory to Unit 1. But beyond that there are no additional safety-related common systems. We do have cross-ties between the main steam systems for operational flexibility in starting up the units up. Dave or Todd maybe, you can mention some of the other shared systems we have.

MR. HORTON: A couple of other systems that we utilize between the two units. The condensate polisher system has the ability to be lined up to either unit to help clean up during startup. As Jack mentioned, the main steam systems have the ability to be cross-tied. For St. Lucie Unit 1 just recently we cross-tied steam with Unit 2 to be able to draw steam into the secondary draw vacuum. Those two are the most primary systems that we utilize between the two.

CHAIR BANERJEE: And none of this was affected in the EPU.

MR. HOFFMAN: No.

CHAIR BANERJEE: You just left it as is.

MR. HOFFMAN: That's correct.

CHAIR BANERJEE: And there are no other shared systems, essentially these.

MR. HOFFMAN: That's correct.

CHAIR BANERJEE: Okay.

MEMBER ABDEL-KHALIK: You indicated that you intend to or have replaced the hydrogen coolers for the generators.

MR. HOFFMAN: They've been replaced actually on both units. We'll get to the electrical modifications shortly.

MEMBER ABDEL-KHALIK: Have you experienced any hydrogen leakage?

MR. HOFFMAN: No. Actually, for EPU we're implementing the modifications in phases, and for St. Lucie Unit 2 we made the main generator modifications during the last outage. Even though we're not at uprate conditions we just -- that was the --

MEMBER ABDEL-KHALIK: But historically

have you had any hydrogen leakage?

MR. HOFFMAN: No. Well, with the new hydrogen coolers, maybe Todd, you can explain how we've been experiencing hydrogen performance on Unit 2 with the change-out.

MR. BROWN: This is Dave Brown with FPL. As Jack mentioned earlier we changed out the generator hydrogen coolers and exciter coolers on Unit 2 in SL-219. Performance up to this date has actually been improved over what we had had in the past and in the hydrogen there's been very low cubic feet per -- that's the same modification that we just repeated several months ago for Unit 1. This obviously we're at 30 percent operating now and hydrogen leakage shows to be very low.

MEMBER ABDEL-KHALIK: But prior to the replacement had you experienced hydrogen leakage?

MR. BROWN: Over the history of Plant St. Lucie --

MEMBER ABDEL-KHALIK: Right.

MR. BROWN: -- at different times we had had problems with the seals that we had modified over a period of time to correct cases where we had exceeded the standard which is about 700 cubic foot per month. We had exceeded that at different times and we had to do some --

MEMBER ABDEL-KHALIK: Per day.

MR. BROWN: I'm sorry, you're right. Per day, I'm sorry. And that was quite a ways back. We had made changes over a period of time, so at the present going into this we would not have a problem.

MEMBER ABDEL-KHALIK: Okay, thank you.

MEMBER SKILLMAN: Let me ask a question here. The idea of sharing polishers or startup steam between the units. What accidents are sensitive to that sharing?

MR. KABADI: This is Jay Kabadi. From a safety analysis point of view there is none. None of those depend on these -- that's mainly from the operational point of view. From the accident analysis in Chapter 15 there is no impact on that.

MEMBER SKILLMAN: Somehow I see a headline that says, "Inadvertent operation, Unit 2 is heating Unit 1 and guess what happened. Oh, gee whiz." I take it from your answer that your gut feel is that there is no threatening scenario.

MR. KABADI: If that initiates any other thing like -- and that will be covered through the design basis. If any of the change initiates some event that event, unless there is some event which is not currently analyzed, but anything happens on the secondary side, extreme cases have been analyzed. Like this particular condition at least to my knowledge, I don't know what other event it could initiate. It's not in the current design basis, anything that can be initiated through that particular feature.

MEMBER SKILLMAN: Thank you.

CONSULTANT BONACA: You have made no changes to the auxiliary feedwater system so that means that you had excess capacity of the auxiliary feedwater pumps, or have you reduced the level of redundancies in the system?

MR. HOFFMAN: For EPU there were no changes to the auxiliary feedwater system or the flow requirements that we assume in safety analyses. What -- St. Lucie's auxiliary feedwater system consists of two 100 percent capacity motor-driven pumps, and what we consider a greater than 100 percent capacity steam-driven pump. The aux feedwater systems are not shared between the units. And classic Chapter 15 safety analyses would take out a single pump as a result of a postulated accident and the two remaining pumps are obviously more than capable of removing decay heat at EPU levels.

Now, there is an additional event that we looked at as part of the EPU, the feed line break, that does pull into play an event where we have to rely on one auxiliary feedwater pump for decay heat removal and we've performed that analysis as part of the EPU and get acceptable results.

CONSULTANT BONACA: Your feeling was in generator, yes. So, when you talk about in the text full capacity, that means 100 percent ability to remove decay heat.

MR. HOFFMAN: That is correct.

CONSULTANT BONACA: With one pump.

MR. HOFFMAN: That's correct.

CONSULTANT BONACA: Thank you.

MEMBER SKILLMAN: If Dr. Bonaca had asked system change would you have added to your answer?

MR. HOFFMAN: For the auxiliary feedwater system?

MEMBER SKILLMAN: Yes.

MR. HOFFMAN: The only change to the auxiliary feedwater system is the tech spec change for the inventory requirements of the condensate storage tank which is typical for an uprate. No physical modifications.

MEMBER SKILLMAN: Thank you.

MR. HOFFMAN: Regarding the heater drain system, the heater drain pump internals are being replaced as part of the EPU project. And as mentioned earlier --

MEMBER ABDEL-KHALIK: Can I ask a question about aux feed?

MR. HOFFMAN: Sure.

MEMBER ABDEL-KHALIK: Is the ability to handle a feed line break at the uprate conditions with one aux feedwater pump, is that dependent on the change in the setpoint for the low-low steam generator level on which the aux feedwater pumps are started?

MR. KABADI: This is Jay Kabadi from FPL. No, we did not have to take credit for that although that's additional margin we have. The way we ran the analysis, if we applied harsh environment to the current setpoint and we took it all the way to almost 1 percent level in the generators. So we did not directly take credit for that new low flow -- low steam generator level trip setpoint in that analysis. But we did identify that there is additional margin now since we are changing the trip setpoint to the higher level.

MEMBER ABDEL-KHALIK: Okay.

MR. HOFFMAN: Again, as I mentioned, the

heater drain pump internals are being replaced but the motors are retained for those pumps, similar to the feedwater pumps. And we've also made selected heater drain valve and heater drain valve control changes as part of EPU, both because they were required for EPU and also to address some what I'll call legacy issues with some of the existing heater drain control valves.

One modification I'd like to point out is that the project is also resolving a longstanding low margin issue for St. Lucie Unit 1. The existing turbine cooling water heat exchangers have marginal heat removal capability at the current plant power level, and during summer months when the ultimate heat sink temperature which is the ocean water is elevated.

And to resolve this margin issue the EPU project is replacing these heat exchangers with heat exchangers having approximately 50 percent more heat transfer capability. We've also made some hydraulic changes to the intake cooling water system above and beyond the heat exchanger change-out to deliver more intake cooling water to those heat exchangers. And as part of the modification also we've made some material changes that are going to improve the long-term reliability of those components.

MEMBER SKILLMAN: You haven't identified

any ventilation systems in this. Is there a reason for that?

MR. HOFFMAN: The only ventilation system change that we made for the uprate is the change to the containment mini-purge system where we changed that system from a manual system to a remote automatic isolation system to give us the capability to purge the containment online. And those valves of course do receive containment isolation signals now. And it provides additional flexibility. It's very similar to the design we have on St. Lucie Unit 2 and does provide operations with a better means to control containment pressure.

MEMBER SKILLMAN: Does the uprate impact or negatively affect your ultimate heat sink calculations and temperature?

MR. HOFFMAN: No.

MEMBER SKILLMAN: No?

MR. HOFFMAN: No. We still use a 95 degree ocean water temperature as our ultimate heat sink design temperature. History shows that that number gets up to about 88, maybe even 89 degrees, under the most extreme summer conditions. So there's margin.

MEMBER SKILLMAN: Thank you.

MR. HOFFMAN: Okay. Next slide. On the electrical side as we mentioned earlier the main generator stator is being rewound and the rotor is being replaced. Also, the main generator hydrogen pressure is being increased for the EPU to allow the rating to be increased to what we call the limiting component rating of 1,200 MVA for the uprate.

There are a number of additional modifications that we made to the main generator and as we mentioned, all of these were implemented in the previous Unit 2 outage. And we've had excellent experience with the current cycle with those modifications in place.

We also -- as part of the grid stability studies it was recommended that we install a power system stabilizer to our main generator for both Unit 1 and Unit 2, and those modifications are complete for both units. That does improve the reliability of the performance of the grid.

I'd also like to point out another low-margin issue that has been problematic over the years that has been resolved as part of the EPU project. It has to do with our voltage margin at our 480 volt bus level. Currently we have limited margin between the degraded voltage relay setpoint and the calculated bus voltage during the most limiting electrical loading event. And for EPU we've made a number of additional electrical system modifications to increase that voltage margin.

MEMBER SKILLMAN: What have you done?

MR. HOFFMAN: What have we done? For -- this is the -- the limiting event is the power systems branch, the PSB1 scenario, where the switchyard or the grid is at the minimum voltage level and you have an event such as a loss-of-coolant accident without loss of offsite power and you challenge your degraded voltage relays which for us are at the 480 volt level. And we had about 2 volts of margin pre EPU for the reset of those relays, and we've made a number of modifications to increase that margin up to about 22 volts.

We've replaced the current limiting reactors in that electrical string to reduce the impedance. We've also added similar to St. Lucie Unit 2 some trips on safety injection on some of our non-essential switchgear. It makes the two units similar, provides us additional margin there. We also trip the main feedwater pumps and the heater drain pumps. They would be isolated anyway because main feedwater isolation comes into play during the accident. So basically what we've done is added some additional SIAS trip, safety injection trips to house loads to increase that margin and provide us, you know, substantial margin to ensure we stay on the preferred power source which is offsite power. And not swap to the diesels during that limiting event.

MEMBER SKILLMAN: Thank you.

MR. HOFFMAN: Okay. Unless there are any other questions for me I'd like to turn the presentation over to Rudy Gil who will discuss the EPU evaluations performed for the St. Lucie 1 steam generators.

MR. GIL: Good morning. My name is Rudy Gil. I am the programs engineer and manager for FPL. As Jack indicated, I'll be presenting a summary of the steam generator analysis associated with the power uprate for St. Lucie Unit 1.

The information selected for this presentation is based really on areas of interest pointed out by ACRS committee during our vast experience with Point Beach and Turkey Point power uprates.

I would like at this point to try to address the question relative to St. Lucie Unit 2. I guess in more simple terms they are different manufacturers so we have a B&W Canada design for St. Lucie Unit 1, an AREVA design for St. Lucie Unit 2. Obviously significant wear indications that we've experienced on St. Lucie Unit 2. We have completed a very extensive root cause evaluation in order to understand the consequences.

And without getting into a lot of details on Unit 2 specifically, it really comes down to manufacturing issues. So concerns during manufacturing process that affected the very important gap distribution between the tubes and the tube supports. So having that knowledge, obviously we can look at Unit 1 to ensure that we don't have that same concern.

I'll speak to performance on Unit 1 a little more, but obviously that unit has been in operation for over a decade now with very good performance.

MEMBER SHACK: And this is a stainless steel egg crate tube support plates?

MR. GIL: Yes, it is.

MEMBER SHACK: And all the supports, the anti-vibration stuff, everything is stainless steel. There's no carbon steel anywhere?

MR. GIL: That is correct. Yes and of

course this is Alloy 690. So it's obviously all the latest lessons learned from the industry. We're still trying to get the wear right.

MEMBER REMPE: On Unit 2 how did you resolve it if it was manufacturing difficulty? You're still running Unit 2. Apparently you've lowered the flow.

MR. GIL: Yes. The -- we have already conducted two inspections on Unit 2 and based on the root cause that we found the -- so based on the root cause and really operating experience in the industry since the beginning associated with wear our expectation is continued attenuation of that wear. And we saw significant reductions from our first inspection to our second. And of course because of the -- I mean, when we do our operational assessments and we show significant margin with respect to tube integrity over the cycle.

In addition to that we actually, even beyond what the probabilistic analysis tells us we actually plug more conservatively in that. Especially during the first cycle until we were able to complete our root cause evaluation. So, the -- really our main plan is that, as you know, for the newer designs we could -- if everything goes well we could do, skip cycles. We are not obviously taking advantage of that for St. Lucie Unit 2. You know, and we'll continue to inspect until we're confident that this mechanism has attenuated to a point where we are comfortable.

MEMBER SHACK: Did you ever get enough wear that you couldn't pass your pressure test at the end of a --

MR. GIL: No. We have not had anywhere near integrity concern. On Unit 2 the highest wear was right at the 40 percent level. And of course that's -- really we plugged that because that's your tech spec limit, but it's not because there was anywhere near -- we have criteria that would trigger us to do an in situ pressure test and we were nowhere near that. Any other questions relative to that comparison?

MEMBER REMPE: No. Maybe later when we're talking Unit 2.

(Laughter)

MR. GIL: I'll have a lot more for you at that time.

CHAIR BANERJEE: Since we are not that familiar with the B&W steam generator, could you tell us a little bit about how it's built and you know, what -- is it a square pitch, a triangular pitch, how those tubes are supported? Just give us a little sort of overview of the design.

MR. GIL: I do have Steve Fluit here from B&W who was involved in that design. It is a tri-pitch type design.

CHAIR BANERJEE: Is that a triangular?

MR. GIL: Triangular, with a fan bar design in order to provide the support for the --

CHAIR BANERJEE: If this is proprietary information we can do it under closed session. But I don't have a clear picture of what this -- is it like a CANDU steam generator maybe?

MR. GIL: Steve, can you provide a little more information?

MR. FLUIT: Yes. Steve Fluit from Babcock & Wilcox Canada. So the tube support structure, if you're familiar with the CANDU steam generators --

CHAIR BANERJEE: Is it both plates?

MR. FLUIT: -- Darlington. No, it's more similar to the latest newer CANDU steam generators such as Darlington. The tube supports in the straight leg region of the tubes are lattice grid type supports so it's kind of similar to an egg crate design arrangement of flat bars. And then up in the U-bend we have what are called fan bar assemblies. So again, there's flat bar strips, there's fan bar/flat bar strips, and then there's a more or less horizontal collector bar that the fan bars are welded to.

And when the steam generator is tubed it's tubed with the tube ends in a horizontal plane. And the bundles built up by inserting the tubes in one plane and then the fan bars are laid on top, and then the next plane of tubes is laid in. So as a result of that manufacturing process the positioning of the fan bars, the U-bend supports, is assured. And then the fan bars are supported by an external structure that sits outside the U-bend and ties all the ends of the various layers of fan bars together with an external skeletal arrangement.

CHAIR BANERJEE: Do you have a sketch you could show us in a closed session or something?

MR. FLUIT: Yes. I can get one.

CHAIR BANERJEE: Yes, you can get one. That's great. And the size, are these steam generators let's say about the size you built before or are they bigger?

MR. FLUIT: Well, we've built several of the CE replacement steam generators, so there's Millstone, St. Lucie and Calvert Cliffs. So, those designs are all similar and they are the largest in diameter of all the steam generators that we've built.

CHAIR BANERJEE: And do you have velocity conditions which, you know, after the uprate? Have you had any of these steam generators exposed to similar velocity conditions in the U-bend regions?

MR. FLUIT: I guess we'll be getting to that in a minute, but in terms of the CE 67 replacement steam generators with the power uprate then St. Lucie Unit 1 will be operating with a higher velocity, slightly higher velocity than the other plants which have not been in operation.

CHAIR BANERJEE: So, you're pushing the experience band with this if I understand it?

MR. FLUIT: It's -- yes. It's a modest increase I guess of --

MEMBER RAY: Can you go to the next slide as long as we're talking about modest increases? Thank you. Look at the top right box there, Sanjoy.

CHAIR BANERJEE: Okay.

MEMBER RAY: I mean, he's right. The next slide calls it a slightly higher, but it's -- I think the question is to what extent is the experience being extended. And I think it's shown here. Because I would surmise that may be as high as you've -- well, I'll ask the question. Have you seen anything as high as that in anything that you've been responsible for?

MR. FLUIT: Rho v squared on itself is one parameter, but you also have to look at the number of supports in the support spacing.

MEMBER RAY: That's right. I gather your answer's no.

MR. FLUIT: I'd have to look and see the numbers.

MEMBER RAY: Okay.

CHAIR BANERJEE: I guess there are two aspects to this. One is of course the rho v squared, but the other as you say is related to geometric parameters, supports and sizes and things like that. And does Darlington or any of these other steam generators have velocities at rho v squared in this range?

MR. FLUIT: I think the better parameter to look at is the results of the flow-induced vibration analysis. So, if you look at the fluid-elastic instability ratio or the random turbulence amplitude response because that takes everything into count. That looks at your velocities, your densities and your support spans and the flexibility of the tubes and everything. And in that regard the operated St. Lucie values are not anything different than what we typically see for other analyses of steam generators.

MEMBER RAY: The real question, I'm sure it's occurred to you as well, is are we going beyond our ability to make that calculation accurately that you're just now referring to.

MR. FLUIT: I would say no. I mean, the parameters that we're operating in are not substantially different from the typical industry parameters.

MEMBER RAY: Well, that's what we're trying to look at in this table here, for example.

MEMBER SKILLMAN: Isn't it accurate to communicate that your operating year now, the real change is the density as a result of increasing T-hot. But if you're still, if you're running 200,000 gallons per minute per loop then your generators are already seeing this mass flow rate because you're changing motors but not rotating elements. So you're getting the same mass flow rate through these generators today that you will get when you are approved for a power uprate. The real difference is you're changing your T-hot density. It's decreased. You're almost there.

So, wouldn't it be more accurate to communicate we're doing this right now and have been doing it for some number of years because we didn't change the rotating elements in the reactor coolant pumps. Isn't that accurate?

MR. KABADI: That is correct. From the primary side flow the only change would be as you mentioned in the density. The flow --

MEMBER RAY: I'm not sure how that affects vibration though, Dick.

MR. GIL: Yes, this is really -- obviously the issue -- the main driver for the concern with vibration would be on the secondary side. And that's what these numbers that we've been discussing --

CHAIR BANERJEE: And perhaps in the U-bend reason.

MEMBER RAY: Yes, for sure.

CHAIR BANERJEE: The concern that we have.

MEMBER RAY: Well, your prior slide, if you go back to that one, I think shows your results are as you characterized them within the range that you consider acceptance criteria. I think the only point of the discussion here now is whether it's outside the range of experience that the calculation is able to confidently make. And that's why I was asking the questions that I did. Because I think that this rho v squared, you know, you can call it slight if you want, but it could take one beyond your range of experience, conceivably anyway.

MR. FLUIT: If I could just clarify the point I made before. These values here are definitely within the range of our experience.

MEMBER RAY: Well of course, but these are calculated values, right?

MR. FLUIT: Right.

MEMBER RAY: Okay.

MR. FLUIT: So is rho v squared.

MEMBER RAY: It is, but I have a lot more confidence in the rho v squared calculation than I do this calculation which is another stage of uncertainty involved. Nobody's implying that it's not correct, I'm just saying is there experience for calculating these results given that rho v squared number that you have there and the others that go with it. That's all that's being asked about.

CHAIR BANERJEE: So just to put something in context. In comparison to the San Onofre steam generators, are these about the same size or are they smaller?

MR. FLUIT: I believe the San Onofre steam generators are larger.

CHAIR BANERJEE: Larger, okay.

MR. FLUIT: I'm not personally that familiar with the San Onofre steam generator design.

MEMBER RAY: Rudy, in the winter, from 600 to 690 in the replacements, what happened to the -- you had to increase the surface area presumably.

MR. GIL: Yes.

MEMBER RAY: How was that accomplished? Longer tubes, more tubes, closer spacing? How did it get --

MR. GIL: I understand that was more tubes, but Steve, do you have the details on that?

MR. FLUIT: Yes. I believe the tube-free lane was made a bit smaller. So there were some extra tubes added there. And I believe the tube --

MEMBER RAY: Did they remove their support post or is there still a support post?

MR. FLUIT: St. Lucie still has the state cylinder, yes.

MEMBER RAY: State cylinder.

MR. GIL: One of the other things I'd like to add, obviously we have confidence in the analysis that's been performed and the comparisons to the industry. However, we will be performing a steam generator inspection at the end of the cycle. In fact, in this case it will not be a full cycle of operation under extended power uprate conditions. So of course, it'll be sufficiently long enough to let us know whether there's any abnormalities.

CHAIR BANERJEE: Can you just go over your inspection schedule? Perhaps that would be useful to know.

MEMBER SCHULTZ: Here also, Rudy, what is the inspection plan? What is being done specially to look at the generator after the first partial uprate cycle?

MR. GIL: Okay. So the history on the inspection, to start with that question. As required at the time we did inspect the first two cycles after the steam generators were replaced. And then after that we went to a skip cycle where we went three cycles in between inspections. And that was of course once we were comfortable with the performance of the steam generators.

And even with that what we've been doing because, as you saw, there was some slight wear that we saw early on which is not atypical necessarily for steam generators. But we actually plugged in very conservative values. We didn't leave anything in service above 20 percent just to make sure.

And then during the last inspection which was in 2008 there were no issues. All the early wear issues that we saw that had led to the plugging that we had done had all attenuated to very acceptable levels. As I said, the next inspection will be right after the first cycle of extended power uprate operation.

CHAIR BANERJEE: It will be what period of time?

MR. GIL: The last inspection was in 2008.

CHAIR BANERJEE: When will the next one be?

MR. GIL: That'll be fall of 2013.

CHAIR BANERJEE: That'll be about a year after you operate under uprated conditions. Roughly.

MR. GIL: I don't know exactly what our -- based on -- probably we're going to get probably sufficient time to be able to assess that condition during the inspection. But obviously shorter than a full cycle.

To answer the second question, what we do especially since our practice has been to go to skip cycles, we do 100 percent bobbin inspection. And as you know, for wear type indications bobbin is the qualified method. Of course, so we look very careful at all of that data, but we do 100 percent bobbin inspections. If there's anything out of the ordinary we see then we proceed to a rotating type inspection. But again, the bobbin is a very good accurate method for this type of indication.

MEMBER SKILLMAN: Would it be your intention to install some not safety grade, but just some commercial grade listening equipment?

MR. GIL: Well, from a -- I mean from -- we do have loose part monitoring that is in place.

MEMBER RAY: It's a pretty noisy environment.

MR. GIL: That's for other conditions. But we have not had -- as far as from an inspections standpoint these tubes are very good, very low noise and so we do get very good inspections.

MEMBER RAY: Well, if tube-to-tube contact is the mechanism it's basically nothing until it happens and then it can be at a high rate. So, the precaution of doing a thorough inspection after the first cycle is appropriate.

MR. GIL: Yes, and in fact one of the things that we do is we use frequencies with the analysis techniques in order to ensure that if there is any tube-to-tube contact that we are able to address that. With these larger steam generators, proximity is always a concern in the outer areas. So from the beginning we've always been looking for that and have the right frequencies and techniques in order to look for that. And obviously, since the SONGS event that's something we're, you know, further taking a look at.

MEMBER ABDEL-KHALIK: Your steam flow rate, your current steam flow rate is 11.8 million pounds per hour. And at the EPU conditions the steam flow rate is 13.42 million pounds per hour, which is a 14 percent increase. Your steam conditions haven't change. The steam pressure hasn't changed, your moisture carryover hasn't changed, your recirculation ratio probably hasn't changed. So why doesn't the volumetric flow rate scale by the same ratio?

MR. GIL: Steve, will you?

MR. FLUIT: Yes, I can answer that. The circulation ratio does change in the steam generator. As a result of having more steam flow going through the steam generator that increases the pressure drop through the lattice grids and the support plates which tends to have a reducing effect on the circulation ratio. So the circulation ratio decreases from 4.3 at the current power conditions down to 3.89 for EPU conditions. So that offsets the impact of the increased steam flow.

MEMBER ABDEL-KHALIK: Okay, thank you.

MEMBER SCHULTZ: We heard that the fluid-elastic instability velocity ratio is something that you want to pay attention to with regard to the tube performance. And we have the result here that meets the acceptance criteria. But how has that changed?

MR. GIL: The previous value was 0.69 so the increase was approximately 0.05.

MEMBER SCHULTZ: Thank you.

MR. GIL: I think I've covered some of the items that were in the presentation.

CHAIR BANERJEE: So how does -- does B&W have its own proprietary sort of database and evaluation methodology that is used to evaluate the behavior of these increased flow conditions?

MR. FLUIT: Yes. So the methodology that we use is based on standard approaches that are published in the industry. We look at fluid-elastic instability, random turbulence excitation and vortex shedding.

The code that we use to actually crunch the numbers is a B&W proprietary code, but the methodology and the inputs that go into the code, for example, with respect to calculating damping and forcing functions are based on information that's publicly available in the literature.

And the velocity and density profiles are based on our 3D thermohydraulic calculations using the ATHOS program.

CHAIR BANERJEE: So you use ATHOS as a basis for that.

MR. FLUIT: Yes, we do.

CHAIR BANERJEE: And is there any change in the version of ATHOS, or is it sort of the standard version?

MR. FLUIT: B&W has a version of ATHOS that we've made a few changes to. The version that we're using for the EPU analysis is the same as the version that was used for the original St. Lucie steam generator analysis. And the modifications that we've made to the ATHOS program have gone through the, you know, the QA process and meet all the QA requirements for this type of analysis.

CHAIR BANERJEE: And the various criteria that you use, the literature version that ATHOS does primarily just the thermohydraulics calculations. You use ATHOS just for getting the velocity and the point distribution.

MR. FLUIT: Yes, that's correct.

CHAIR BANERJEE: And -- okay. Thank you. Let's keep on. But we will want to see a diagram of the steam generator.

MR. GIL: Okay. So we'll take an action to get a diagram for you. We can share that with you during the closed --

CHAIR BANERJEE: Right. Because it's sort of the first time we've seen one of these.

MR. GIL: Sure. Okay. As we've been discussing, the analysis performed for the steam generators has demonstrated acceptable tube wear at the proposed uprated conditions.

As shown on this table, the key acceptance criteria are satisfied with good margin. These criteria as discussed include the elastic -- fluid-elastic instability, vortex shedding and the -- of course the predicted end of life wear.

The analysis shows that the wear in the U-bend area increases only slightly so the results show an initially predicted 12.7 percent wear level. And that increases to 12.9 percent level.

Actually, overall the area with the highest predicted wear is the tube bundle entrance area, and this area really has not been affected. In fact, if anything it goes down by a couple of percent based on some of the discussions on the flow. Any other questions on this slide? Okay. Chris, next slide.

Okay, we've already touched on this slightly, but in addition to performing the required analysis we compared the various parameters under uprated conditions to those of other installed steam generators. As we discussed, we wanted to compare to obviously our current conditions and performance. And as Steve previously mentioned we compared to other B&W installed generators that have had substantial runtime. And those were the Millstone Unit 2 and both of the Calvert Cliffs steam generators.

So, in conclusion, the revised parameters that are affected by uprate -- as expected, they are affected by the increased levels but remain within what we consider to be comparable to industry experience. And as I mentioned before, you know, we will be providing verification of that when we do our inspection which is scheduled right at the end of the first cycle.

The St. Lucie steam generators have performed very well. Although rho v squared as discussed is slightly higher it is comparable with current experience and we're showing that the increase in the bundle wear rates only increase slightly and are well below the technical specification criteria of 40 percent which is a conservative number with respect to the total integrity of the tubes.

The industry has seen many years of operating experience with no indication of tube vibration problems with steam generators comparable to the models installed in St. Lucie Unit 1. Periodic steam generator tube inspections at St. Lucie Unit 1 have provided no indication of unusual wear. The steam generators performed very well with only 14 tubes plugged in steam generator 1A and one tube plug in 1B. The 1B wear was a result of a loose part. That part was removed during the outage when it was identified.

No tubes have been plugged since the inspection performed in 2004. And as I mentioned earlier, we have really applied a very conservative approach to plugging because of the -- our inspection process.

Although not anticipated by analysis, ongoing steam generator tube inspections will provide early indication of any problems. Steam generator inspections planned for the first refueling outage after operation under EPU conditions -- and as I mentioned, in this case it'll actually be a shortened cycle based on when we are implementing the actual uprate conditions.

That concludes my presentation pending any additional questions.

CHAIR BANERJEE: Okay. So, if we don't have -- if we have questions of course this is the time to ask them. If not, what I propose is that we take a 15-minute break. This is a natural time to do that. We are slightly ahead of schedule, but I think you know, with all the uncertainties facing us things may change as we go on. So, let's reconvene at 10:15, okay? So we'll take a break. Thanks.

(Whereupon, the foregoing matter went off the record at 10:00 a.m. and went back on the record at 10:15 a.m.)

CHAIR BANERJEE: We are back in session. Jay, I guess you're going to lead this.

MR. KABADI: My name is Jay Kabadi. I'm manager of Nuclear Fuel Engineering for St. Lucie. In the next few slides I will go over some of the implications of EPU on fuel design, core design, and also provide some results of EPU safety analysis.

For EPU, we did not implement any fuel design change. We will continue to use AREVA HTP 14 by 14 fuel. HTP is their high thermal performance fuel which we have been using for the last about -- more than 10-12 years.

MEMBER ARMIJO: Just background. What has the fuel performance experience been at St. Lucie 1 with this fuel?

MR. KABADI: St. Lucie in the last few years has been performing extremely well. We had some unrelated to actual core conditions but grit-rod type frettings before we had HTP fuel. Since HTP fuel has been introduced we have an excellent performance. No indication of any great -- fretting type issues. At the same time we do inspections every cycle at the end to see how the fuel behaves in terms of crud and we don't see anything, any type of issues.

MEMBER ARMIJO: Okay. And no other mechanisms that have been affecting your fuel reliability?

MR. KABADI: That is correct. We have been continuously improving our chemistry in order to do that, for all of our fleet, and we had excellent performance at St. Lucie Unit 1.

MEMBER ARMIJO: Thank you.

MEMBER SHACK: Do you do anything unusual with your chemistry?

MR. KABADI: We try to follow new guidelines coming from EPRI for example.

MEMBER SHACK: But you don't add zinc or anything?

MR. KABADI: Yes. We do a constant pH program in the last couple of cycles and tried to get to 7.2. And we introduced zinc injection I think about two cycled ago for St. Lucie 1.

MEMBER SHACK: Is that now fairly standard PWR water chemistry?

MR. KABADI: Yes. I think right now in the PWR people have been moving from the modified lithium or pH program to a constant pH program. Sometimes we get limited at the beginning of cycle based on the boron but we are trying to achieve that 7.2 and run it constantly through the fuel performance.

MEMBER ABDEL-KHALIK: Do you ultrasonically clean the bundles after each cycle?

MR. KABADI: Not at St. Lucie. That is correct.

MEMBER ABDEL-KHALIK: You don't do any cleanup of the bundles at all?

MR. KABADI: That is correct.

MEMBER ABDEL-KHALIK: You don't have any

crud issues?

MR. KABADI: That is correct. For St. Lucie we didn't have any crud issues. But we keep on tracking every cycle just to see how the fuel performs.

Although not required for EPU we have addressed in the EPU analysis two guide tube designs. One is the standard guide tube design which we currently use and the other is a MONOBLOC design with some minor changes, and that's mainly in the dashboard region. The thickness wall is likely greater to provide more sturdiness. It's pretty much insignificant from any analysis standpoint.

Assembly and the rod burnup limits remain unchanged. Our current rod peak burnup limit is 62,000 gigawatt-days per MTU and we'll maintain that same for EPU.

MEMBER SCHULTZ: What are you currently achieving in your designs with regard to rod and assembly burnups?

MR. KABADI: For our rod burnup limit is 62 and we tried to stay around 60. And same thing, we will continue for EPU.

MEMBER SCHULTZ: Thank you.

MR. KABADI: The core design for EPU we

are expecting to be similar to what our current core designs are. And to make sure that our safety analysis bounds all the EPU feature cycles we developed representative core designs right from the equilibrium -- for the transition cycle to the equilibrium cycle to get inputs to fit into the safety analysis and then just adjust them slightly to cover cycle-by-cycle variations.

From core design point of view, the limits we are changing slightly to offset some of the EPU impacts on the safety analysis. The main ones in the peaking factor area are the total integrated radial peaking factor F-r. In the CE terminology which is up to date what Westinghouse uses. That is being reduced from 1.7 to 1.65. And the peak linear heat rate we are reducing from 15 kilowatt to 14.7, and that's mainly dictated by small break LOCA.

MEMBER SCHULTZ: And again, with regard to your current operation have you been pushing those limits to the 1.7 and the 15 kilowatt per foot?

MR. KABADI: No. We have to design --

MEMBER SCHULTZ: Design --

MR. KABADI: Yes, we designed about 4 to 6 percent below that limit typically. And we'll follow, now we are reducing that and we'll design about 4 to 6 percent below those limits.

MEMBER SCHULTZ: So you're correspondingly reducing the limits. You really haven't operated to those limits.

MR. KABADI: That is correct. We --

MEMBER SCHULTZ: -- cycle design.

MR. KABADI: That's correct.

MEMBER SCHULTZ: You may be approaching the new limits more closely with the uprated design.

MR. KABADI: But we still -- the design, since our limit is 1.65 we'll design something like 1.57, whatever the 6 percent, between 4 and 6, that's what our target is. In fact we maintain at least 4 percent but as much as 6 percent margin to these new limits, so it will be reduced corresponding to 1.65.

MEMBER SCHULTZ: Thank you.

MEMBER ARMIJO: So, with the margins you use of your own margins what is your peak linear heat generation rate actual? What is your expected? Less than 14.7 then.

MR. KABADI: Yes. All the analysis used at the tech spec COLR limit. When the actual steady state linear heat rate is much lower. In the analysis we do all the -- within the operating band and verified that it stays below that limit. So actual steady state is a significant limit.

MEMBER ARMIJO: Yes, but what is your actual linear heat generation rate at operation?

MR. KABADI: Yes --

MEMBER ARMIJO: What do you believe it is?

MR. KABADI: No, no, that's generally in the range of about 11 to 11 and a half.

MEMBER ARMIJO: That's the point I was trying to get. It's actually --

MR. KABADI: For these -- when we operated it's around that range.

MEMBER ARMIJO: Okay.

MR. KABADI: To meet the increased energy needs for EPU we'll control them by a combination of feed enrichment and the batch size for fresh assemblies. As I think I mentioned briefly in response to some other question, the enrichment we are increasing from 4.5 to 4.6 just to allow more flexibility in case we need that in future. And that is what is in the proposed license amendment.

MEMBER SKILLMAN: Jay, let me ask you a question about that. This is your tech spec 5.6.1.d. And the wording there is changed as follows. The original wording is "having a U-235 enrichment less than or equal to 4.5 weight percent" and the new words are "having a maximum planar average U-235 enrichment less than or equal to 4.6 percent."

MR. KABADI: Right.

MEMBER SKILLMAN: Why did you add the words "planar average?"

MR. KABADI: I think the older tech specs, the real meaning of that was also planar average. I think there was some inconsistency. And what that right now, also the new analysis which you did for criticality that allows fuel pins to be about 4.6, but your average at any plane has to be below 4.6.

MEMBER SKILLMAN: Thank you.

MR. KABADI: And we will continue to use the same burnable absorber which we use, gad, for St. Lucie 1 for many years. And the core loading pattern will be designed to meet all the EPU limits.

From the design perspective we did not have to change any limits on the moderator temperature coefficient. Those limits remain the same. Shutdown margin also we are not changing for at-power operation.

MEMBER ABDEL-KHALIK: What are the MTC limits?

MR. KABADI: The MTC are -32 pcm per degree F. That's our current limit.

MEMBER ABDEL-KHALIK: What is the value at the beginning of cycle?

MR. KABADI: Beginning of cycle at full power we go in the range of about -8 based on the -7 to -9, in that range. We do at the beginning of cycle.

MEMBER ABDEL-KHALIK: You never approach zero even at the beginning of life?

MR. KABADI: Yes, we are way below zero. Only at the zero power, that's where the MTC gets zero or slightly positive. As you go up in power MTC goes negative. At full power we are way below zero.

Shutdown margin also we are not changing any limits. We will stay with our same limits we have right now.

MEMBER ABDEL-KHALIK: So if the shutdown margin remains unchanged and you say that you have a larger Doppler power defect obviously you haven't changed your control rods.

MR. KABADI: Right.

MEMBER ABDEL-KHALIK: So, what is your maximum or what is your excess reactivity for a cold clean shutdown core at the higher enrichment that you're using?

MR. KABADI: Yes, we still try to

maintain. It varies from cycle to cycle. We -- cycle maintain about 400 to 500 pcm minimum margin.

MEMBER ABDEL-KHALIK: That's the shutdown margin.

MR. KABADI: Right, about our tech spec limit which is 3,600.

MEMBER ABDEL-KHALIK: But when you add the shutdown margin and the Doppler defect, the total worth of the rods, and the moderate temperature defect, what is that total for a clean cold core?

MR. KABADI: You're asking without --

MEMBER ABDEL-KHALIK: Without, yes, without controls, without feedback.

MR. KABADI: Yes, I can give you the detail numbers, I'll get them, but what we have, the control rod worth is in the range of about eight to nine thousand, and then we deduct all those power defects in this one. And individual components I'll try to get you for individual if you want. But after deducting all that we still stay about 3,600 which is our COLR limit by about 400-500 pcm.

MEMBER ABDEL-KHALIK: Okay. Yes, I'd like to see those details for the higher enrichment value that you're using.

MR. KABADI: Right. But again, I want to

emphasize here also, although in the tech specs we are changing the enrichment, we usually stay in the range of 4 to 4.4, that's what we have been doing. When we run the EPU cycles which we have designed now we try to stay within that. But what we'll -- I'll try to give you the details of our shutdown margin numbers.

MEMBER ABDEL-KHALIK: Okay, thank you.

MR. KABADI: Now, for the boron delivery requirements we are increasing borons in the boric acid makeup tank in the RWT which is the refueling water tank and also for the safety injection tank. Our safety injection tank and the refueling water tank, boron is being increased from current value of 1,720 ppm to 1,900 ppm.

MEMBER ABDEL-KHALIK: Have you ever changed vendor for your boric acid?

MR. KABADI: Vendor for?

MEMBER ABDEL-KHALIK: Boric acid.

MR. KABADI: Oh, you mean in the --

MEMBER ABDEL-KHALIK: Right. Is the enrichment the same over the years? Have you controlled the enrichment of the boric acid you bought?

MR. KABADI: Right. That's usually from 19.1 and we get that data from the site. And that's actually done by the site people and we stay with 19.1 and then it depletes within the cycle.

MEMBER ABDEL-KHALIK: So you haven't changed vendors?

MR. KABADI: I can get that. I am not directly involved in that, but I can try to get the data whether we changed.

MS. ABBOTT: This is Liz Abbott from FPL. We do not use enriched boron --

MEMBER ABDEL-KHALIK: I understand.

MS. ABBOTT: -- acid. Okay. Yes.

MEMBER ABDEL-KHALIK: I understand. But the enrichment still changes.

MS. ABBOTT: Yes. So that would be part of our regular testing then.

MEMBER ABDEL-KHALIK: So you have a regular test program for each sort of shipment of boric acid that you receive from your vendor?

MR. KABADI: Yes. Boric acid is procured by site and normally they don't change any -- let me clarify to see whether I understand your question. You're talking about the boric acid which we procure to get into the RCS which is typically --

MEMBER ABDEL-KHALIK: Correct.

MR. KABADI: -- in the range of about 19.1

or 20.

MEMBER ABDEL-KHALIK: Right, but sometimes it can be as high as 20 point something.

MR. KABADI: Right, right. And we have not changed for St. Lucie 1 for a long time. Now, whether they have -- what the plan is, if you want that detail you can get them. But yes, we have not changed that for some time though.

MEMBER ABDEL-KHALIK: So you normally wouldn't -- when you start up you hit your estimated critical position within?

MR. KABADI: Yes. We have a very --

MEMBER ABDEL-KHALIK: -- or two?

MR. KABADI: Right, just this current outage we just started we are actually within 5 to 6 ppm.

MEMBER ABDEL-KHALIK: Five to six ppm. That's 60 pcm.

MR. KABADI: Right, but taking into account all these measurement uncertainties and all I think below 10 ppm is a good indication for ECCS.

MEMBER ABDEL-KHALIK: Okay, thank you.

CHAIR BANERJEE: Said, do you have some concerns about the vendor?

MEMBER ABDEL-KHALIK: Well, I mean you

know, as long as they have some control over the enrichment of the boric acid they acquire, and they know exactly what the enrichment is, and they hit their estimated critical positions on startup then I guess I'm okay.

MR. KABADI: Yes, I think -- let me clarify. I think what we do is the vendor site receives boron and they sample our RCS actually for boron. We have periodic check of the RCS samples to see what our b10 is. And we use that to adjust our numbers to provide to the site. So we do take into account the actual value irrespective whether they --

MEMBER ABDEL-KHALIK: I understand with depletion, but I'm worried about the initial batch that you acquire from the vendor.

MR. KABADI: Right, right, but initially also when they put it, they do the testing once they borate the RCS and give us the actual value in the RCS. Take the sample and we know what the actual b10 is in the RCS.

MEMBER ABDEL-KHALIK: Okay, thank you.

MR. KABADI: Yes, going to the next slide. This slide just summarizes the methodology used for our analysis. For large break and small break we are using S-RELAP5 which is a common code package which is probably good from the general maintenance of our methodology point of view. And for DNB analysis we continue to use the XCOBRA-IIIC. Now, S-RELAP5 for both large and small break is a change from our current analysis of record.

MEMBER SCHULTZ: Excuse me, can you go back to the previous slide? On the second bullet, if you could cover that in some more detail. What -- can you describe the parameter biasing that you are doing beyond the approved methodology requirements? Can you describe why you're doing that? And who's retaining the margin here? Are you going to maintain that margin or are you retaining it for --

MR. KABADI: No, I think the variable methodology is approved in the topical report. A lot of parameters there were approved to be nominal parameters. So as part of this review we had for EPU in our discussions with the staff we were biasing all the input parameters in the worst direction to give the more conservative results.

Essentially, margin goes out in terms of limit but margin in terms of if you call that operational margin, not operational margin that we can take. But it's inputs using more conservative values than what so-called the previously approved methodology required. Like pressure, for example. We are biasing all the mean and max values.

MEMBER SCHULTZ: As part of your methodology, your application of the methodology you bias the parameters.

MR. KABADI: That's correct.

MEMBER SCHULTZ: So as you go forward with your safety analysis you're going to maintain those biases.

MR. KABADI: Right. That's what --

MEMBER SCHULTZ: Thank you.

MR. KABADI: Yes, from the safety analysis point of view then we are, as mentioned earlier, reducing the peak linear heat rate at the same time, the radial peaking factor that gained some margin on the analysis. We are increasing the minimum safety injection tank pressure. Our current safety injection tank pressure is from 200 to 250 range. We are moving that from 230 to 280, so essentially moving up by 50 psi.

MEMBER SKILLMAN: The reason that you are doing that is to get earlier injection on a large break LOCA, is that the reason?

MR. KABADI: Small break LOCA.

MEMBER SKILLMAN: On small break LOCA.

MR. KABADI: That's correct. Yes, I think --

MEMBER SKILLMAN: It takes a long time to depressurize on a small break LOCA. Where does the 50 pounds really benefit you?

MR. KABADI: I think in the Combustion Engineering plans once the break size goes a little higher, HPCIs cannot cope with this and unless safety injection starts coming in, the peak clad temperature gets a big penalty. So when you do a spectrum of break analysis there is a point where you rely on the safety injection tank, and that was coming later when our pressure minimum was 200. So once the pressure was increased to 230 safety injection tanks delivered early and that provided a lot of margin for the larger breaks within the small break LOCA category.

MEMBER SKILLMAN: Okay, thank you.

MR. KABADI: Yes.

MEMBER SCHULTZ: I'm sorry, Jay, could you repeat again the current value and where you're going to with respect to the pressure?

MR. KABADI: Yes. The current value range in the tech specs is 200 to 250 psig.

MEMBER SCHULTZ: That's the range currently.

MR. KABADI: Right. And the new value will be 230 to 280.

MEMBER SCHULTZ: Thank you.

MR. KABADI: So as far as the inputs and assumptions used in the safety analysis, we tried to bias them as much as possible to gain more operational flexibility. Physics parameters we tried to bias to cover cycle-to-cycle variations. As far as the operating parameters we have included all the measurement uncertainties and went to the end of the operating bands. For the trip setpoints, all the uncertainties at the same time with the maximum delay times allowed or required by tech specs. We did not take credit for any non-safety grade equipment in the safety analysis.

And the last bullet pretty much summarizes some of the biasing, what we talked about, the RCS pressure, temperature, flow, pressurizer level. When we did the analysis in some limiting events we biased them in either positive or negative directions to get the worst results.

This slide, I think most of these parameters were touched upon earlier either by Jack or in the more packages we discussed during the responses. The MUR, the power measurement uncertainty is reduced from the current value of 2 percent to 0.3 percent and we are recapturing that 1.7 percent in our licensed power level.

The steam generator tube plugging, current analysis have used 15 or greater based on different analysis. We are making it constant 10 percent for the EPU analysis. And as Rudy went through, our current plugging level is very, very low on the steam generator.

The safety valve tolerance, this says we are making the tech spec change to that to give +/-3 tolerance on the first bank of valves and +2/-3 for the second bank of valves. The safety injection tank we will talk about --

MEMBER ABDEL-KHALIK: The ASME acceptance criterion for the setpoint of a safety valve is +/-3 percent, is that correct?

MR. KABADI: That is correct.

MEMBER ABDEL-KHALIK: So, how do you justify tolerances different than the ASME limit?

MR. KABADI: If we go outside this 2 percent for any one particular valve then we look at the full complement of the valves and see whether our analysis done this way with all the valves being at that particular tolerance is okay or not. Generally when the valve testing is done usually one valve sometimes may go a little higher, but most of the valves either stay same or actually come even negative tolerance.

MEMBER ABDEL-KHALIK: So if I do a search on LERs, how many LERs do you think I would find for your plant with the safety valve setpoints outside the range?

MR. KABADI: We follow the NUREG requirements of reporting any valve tolerance violations. And the increase can add to that I think based on whether at the time of discovery if you have more than one then you report. We follow the NUREG guidance on that. And you will see some definitely -- I cannot tell how many, but you will see some violations reported in the LER. In the past few years if you look we have reported some violations.

MR. WASIK: This is Chris Wasik, FPL. Just to distinguish, this is as-found tolerance versus as-left tolerance.

MEMBER ABDEL-KHALIK: Yes, I understand. I mean, right. You have to do it at the end of cycle.

MR. KABADI: That's correct.

MEMBER ABDEL-KHALIK: Okay, thank you.

MR. KABADI: Yes, I think SIT pressure we touched before, and the boron in the safety injection tank. And the refueling water tank we are increasing to 1,900 ppm.

This is, again, just a summary of what we talked about before for non-LOCA. Our EPU analysis is all being done with S-RELAP5, T-H, XCOBRA-IIIC, and then the V&V correlation is the HTP which is the same as what we are currently using.

In the next few slides I just go over some key analysis results, particularly the limiting ones. The first category is the decrease in RCS flow. The limiting events in that category are loss of flow and locked rotor as shown on this slide. With the EPU we got some benefit in those analyses based on the increase in the RCS flow -- thermal design flow, actually. The analysis RCS flow we used. Our loss of flow DNB calculated remains sufficiently higher than what the limit is. In locked rotor we don't get any fuel failures, although our dose analysis is conservatively assuming about 19 percent fuel failures so we are --

CHAIR BANERJEE: Your loss of load I noticed also when I was reading.

MR. KABADI: Right, the next category.

CHAIR BANERJEE: It's very, very close.

Now, can you talk a little bit about what the conservatisms there are?

MR. KABADI: Yes. One thing what in the previous slide we talked about is the biasing of the parameters. We bias all the parameters to get the worst results, RCS pressure, temperature and all combination of all this stuff to achieve the maximum RCS pressure. This is pretty much the limit that in any operating band could happen. So this is a very conservative number.

CHAIR BANERJEE: What is the most sensitive to this? I mean, what do you bias which is the most sensitive?

MR. KABADI: Well, one thing to realize here is the RCS trip coming in is critical here and the safety valves opening. Because the safety valves open at 2,500 so the pressure rises so fast that any minor change produces some pressure increase. So we are biasing all the -- to the maximum uncertainties on this one, pressure at the safety valves under maximum tolerance. Same thing on the main steam safety, the first bank of valves which are more important here, those are also biased to the +3 all the way to the maximum limit. So this is pretty much biasing assuming everything happens in the worst direction at the same time.

CHAIR BANERJEE: And these calculations are done with S-RELAP?

MR. KABADI: That's correct. And this is one of the biasing change which we did. If the pressure becomes significantly lower, if you don't bias those --

CHAIR BANERJEE: The S-RELAP is a best estimate code, right?

MR. KABADI: It's a licensed code.

CHAIR BANERJEE: But I mean you're using it in a way which is -- I guess for the small break LOCA you also use it in a way which is very conservative. I'm just trying to -- the large break LOCA, it's tuned to be a best estimate, right?

MR. KABADI: Yes, it's one code package and probably AREVA can --

CHAIR BANERJEE: I'd like to understand what --

MR. KABADI: Can you just?

MR. LINDQUIST: This is Tim Lindquist, AREVA. The S-RELAP code is AREVA's version of RELAP5 MOD2. And it's been used in various forms initially as ANF-RELAP which is one of the codes that is currently used to license St. Lucie 1. And the conversion of the code to S-RELAP was primarily to be able to do the realistic large break LOCA analyses. But as far as the non-LOCA safety analyses go, they're all done deterministically.

And so a code models the physical characteristics and geometries of the plant, but the setpoints are all biased deterministically. The operating parameters are biased in a deterministic conservative direction. Valve setpoints are all set to the maximum tolerances. And so in that fashion for non-LOCA analyses it's very much a deterministic type calculation.

CHAIR BANERJEE: So it's also deterministic for large break LOCA, you just sample your parameters from some space in some way. It's always a deterministic code.

MR. LINDQUIST: Well, deterministic from the standpoint of --

CHAIR BANERJEE: How it's used is different, yes.

MR. LINDQUIST: Yes, of how it's used. Again, for non-LOCA all of the uncertainties and setpoints are intentionally biased to the most adverse -- in the most adverse direction.

CHAIR BANERJEE: And it's clear how to

bias them?

MR. LINDQUIST: In many cases it is. If there is some doubt there were some sensitivity calculations done to define the direction.

CHAIR BANERJEE: So, if we go back to this loss of load, there must be some particular things which it is very sensitive to, right? As you pointed out. And did you guys do this -- you did the analysis, right? For the --

MR. LINDQUIST: Yes, that is correct.

CHAIR BANERJEE: Okay, so I'm asking the right person. Okay. How sensitive is it to opening these valves and so on? If you get it wrong by a little bit, what's the uncertainty here?

MR. LINDQUIST: I think the typical pressurization rates are on the order of maybe 100 psi per second. And so the pressure is increasing very dramatically in the pressurizer. And so a delay in a RCS trip, for example, I believe the -- well, the trip setpoint is on the order of 2,435 psia and the operating pressure obviously is 2,250 psia. The delay on the trip is, if I remember right, about 29 seconds. And so again, in these calculations the setpoint is set to its maximum value and delay is --

CHAIR BANERJEE: I don't mean for the

physical time. I mean in terms of when you say this is biased we always get the feeling that this is some enormous thing. Is it a fraction of a second which it's biased by? Or how much is the bias?

MR. LINDQUIST: Are you referring to say a best estimate type calculation versus deterministic?

CHAIR BANERJEE: Yes. What would be the real -- what is the real bias in time? What was the difference? Is it 0.5 seconds? Is it 0.2 seconds? What is the number.

MR. LINDQUIST: You're comparing a best estimate calculation to a safety analysis deterministic calculation.

CHAIR BANERJEE: In this case, loss of load. What is the bias in terms of time compared to best estimate?

MR. LINDQUIST: Well, I guess if you look at just the setpoint itself --

CHAIR BANERJEE: Not the setpoint. Time.

MR. LINDQUIST: Yes. If you look at just the setpoint itself it's biased roughly speaking, say 50 psi, a little less than 50 psi.

CHAIR BANERJEE: But how much is --

MR. LINDQUIST: And so that in and of itself would be about 2 seconds.

CHAIR BANERJEE: Other way around.

MR. LINDQUIST: Or I'm sorry, a half a second. I'm sorry, half a second.

CHAIR BANERJEE: Okay. So that's what I was trying to understand. So, that number has a certain uncertainty in it because these are very, very small biases in physical terms.

CONSULTANT BONACA: Now you do what you said that you do. You set the parameters or the limit, et cetera. What if you get 2,900 psi?

CHAIR BANERJEE: Then you bias it less I guess.

(Laughter)

MR. KABADI: No, I think just to clarify, we did bias to what the max our upratings are. For example, just biasing that we start at the lowest allowed tech spec pressure and allow additional uncertainty on that, that itself gave us about, Tim can correct, 20-30 psi penalty on that. So we did bias to what our operations would be. It is not -- and that's what these numbers are.

CHAIR BANERJEE: I understand what you did. What is -- sort of I'm trying to understand better is in physical terms. You know that people say "I biased this by 50 psi" or whatever? When things are rising at 100 psi per second that bias means that physically you bias things a half a second. It's very, very hard to get, you know. You can always get -- get these things.

And really what I'm trying to understand is the uncertainty. When you get 2744 as a result it's a level of precision which is amazing to me in a transient of this type. So, I'm just wondering how much physically this is biased. I mean, if things open slightly later are you going to get to 2,900 or whatever?

CONSULTANT WALLIS: But it's not just the biasing, it's also the methods employed by the code itself.

CHAIR BANERJEE: Which are very uncertain.

CONSULTANT WALLIS: Which are uncertain. So, and that's not figured in this at all.

CHAIR BANERJEE: So the question is how much of a hard stop is this 2,750 there or 1,100? What happens if it exceeds? Imagine in real life it is exceeded, whatever is. What happens after that?

MR. KABADI: But I think, again, the things which will eventually depend on your safeties. And that's why those setpoints, there are some limits that those are verified. Irrespective how the threat comes, a little slightly later like we said, instead of -- there is some bias in that. But eventually safeties, if they don't open within the time frame or within those tolerances, that will create higher pressures.

CHAIR BANERJEE: If there is a higher pressure, what is the consequence? That's what I'm asking. Do you fall off a cliff, or does it -- is everything gradual?

MR. KABADI: With design basis point of view 2,750 is the limit. That's the only thing. But in the real -- real failure pressures are much higher.

CHAIR BANERJEE: Right.

CONSULTANT BONACA: You said that you're setting parameters at the limit which implies you are not at the limit. And you can't back it off. I mean, the question is how do you handle it. I know it is a technique that is used to gain some margin there, but the question is what do you, you know, how do you proceed physically?

MR. HALE: Hi, this is Steve Hale, Florida Power & Light. Just wanted to talk -- we're talking about AOOs here, okay. The 2,750 is not a hard stop. It's an acceptance criteria for an anticipated operational occurrence. If you look at it from a code standpoint, there's certainly a lot more margin in the design of the system well above the 2,750. So it's not like you're going to get, you know, rupture once you exceed that point.

And I'd also like to point out that for the loss of load, and correct me if I'm wrong, Jay, but we ignore the reactor trip on turbine trip and we're also ignoring the first safety-related reactor trip. Is that correct?

MR. KABADI: That's correct.

MR. HALE: And we're taking the second safety-related reactor trip. So that's another conservatism.

CHAIR BANERJEE: Why are you doing that?

MR. HALE: It's consistent with the Standard Review Plan.

CHAIR BANERJEE: Okay.

MR. HALE: So I just want to clarify, the 2,750 is our acceptance criteria for anticipated operational occurrences. Certainly the -- by code the pressure design of the system is much larger than that. And I just wanted to make sure that we highlighted the specific conservatism just in the assumptions on what you trip on.

CHAIR BANERJEE: So, if you tripped

according to plan what would happen?

MR. KABADI: You're talking about in real?

CHAIR BANERJEE: Yes.

MR. KABADI: In the real thing if you have a loss of load type event your steam time bypass will pass all steam and we probably may not even open safeties. So real pressure increases will be way below.

CHAIR BANERJEE: How much? I mean, where --

MR. KABADI: Right now, as a part of the EPU we are even making changes to steamline bypass to prevent safeties opening. Right now in the design basis all the safeties open so it is a very, very conservative calculations done to show that even in the worst case it will not violate, as Steve pointed out, even the design basis number which is 2,750 although the real --

CHAIR BANERJEE: So, leaving that aside, how much were those numbers before the EPU?

MEMBER SHACK: 2,749.

CHAIR BANERJEE: A different methodology, I guess.

MR. KABADI: Right. I think to do the fair comparison, EPU number using the same type of assumptions, biasing what we talked about, I think we are getting numbers in the range of low 2,700. And that's what our pre-EPU analysis did not bias all these in the worst direction what we did now. Now, this 2,744 had that additional biasing.

And secondly, I think the current analysis -- Tim, correct me. I think it was not done with the S-RELAP5, right?

MR. LINDQUIST: That is correct.

CHAIR BANERJEE: Yes, I saw that was written somewhere. So you don't have a 1 to 1 comparison as to the effect of the EPU on these pressures. Done with the same methodology, done with the same assumptions.

MR. KABADI: Tim, do you recall our current numbers?

MR. LINDQUIST: I don't, but we can certainly --

MR. KABADI: We can get it. But that without biasing may give you some comparison. Those will be similar type inputs except going to EPU.

CHAIR BANERJEE: Didn't you have to do those biases at the time that analysis was done?

MR. KABADI: For the original analysis.

CHAIR BANERJEE: The original. Anyway, it would be interesting to see what those numbers were.

MR. KABADI: Yes. We had the number for EPU --

CHAIR BANERJEE: EPU and post EPU.

MR. KABADI: Right. Right. I think we have both of those because we have it on EPU without biasing, the operating parameters.

CHAIR BANERJEE: Yes. This is pretty close so I think we should get a little more information.

MEMBER ABDEL-KHALIK: Can I follow up on this?

CHAIR BANERJEE: Yes.

MEMBER ABDEL-KHALIK: Historically what was the maximum setpoint drift for your safeties that you found over the years compared to the acceptance criterion?

MR. KABADI: I know that we have gone about 3 percent in some valves, but not all the valves. But I don't recall. We can find out if you want to know.

MEMBER ABDEL-KHALIK: Wouldn't it be appropriate to look at your actual historical performance and see what the maximum setpoint drift is and set the safety setpoint at that value?

MR. KABADI: For all the valves?

MEMBER ABDEL-KHALIK: Well, for whatever number of valves.

MR. KABADI: Normally what we do is when we look at the valves it looks like on the average we are actually even below the nominal setpoint. Some valves may be 1 percent plus, some may be 1 minus, some may go a little higher. Few -- once in awhile we do see above 3. But that's a rare, rare case where we do see above 3 percent.

MEMBER ABDEL-KHALIK: But the point is if the safety's setpoint drift is a documented occurrence that you've had in the past, how are you taking that into account in your calculations?

MR. KABADI: Right now we don't have what I call is a consistent set that says there are valves that are always going above 3. If we had that probably what you are saying probably is a good thing. But we seldom see a valve going outside. And periodically maybe one valve.

MEMBER ABDEL-KHALIK: Seldom and periodically don't jive somehow.

MR. KABADI: We can see the data, some of the -- and provide that. But historically we have not seen valves continuously failing above 3 percent.

MR. HOFFMAN: That's my recollection. We'll pull those records for you. Typically we do the testing of the main steam safety valves during each shutdown.

MEMBER ABDEL-KHALIK: Right.

MR. HOFFMAN: So we have a large database of those results. And my recollection is for the most part the valves test basically at or even in limited cases below the setpoint. We can pull the information.

MEMBER ABDEL-KHALIK: Right. I'm interested in valves that fail high.

MR. HOFFMAN: Sure. Understand. We can -- we'll pull that.

MEMBER ABDEL-KHALIK: Okay. Thank you.

MEMBER SKILLMAN: Jack, when you test at each outage, do you test just the lifting pressure or do you test the blowdown based on the huddle chamber and the blowdown ring, the reaction chamber?

MR. HOFFMAN: My understanding is we just test the setpoint. I'm not -- I don't know what validation we do of the blowdown ring settings. We don't obviously measure actual blowdown, I don't believe, but we can check that. We have a plant-specific procedure and we use the Trevitest method for main steam safety valve setpoint testing.

MEMBER SKILLMAN: I make the comment because you could have a valve -- you could have two identical valves, two identically appearing valves. Each could lift an identical pressure. And if the huddle chamber and the blowdown rings are set differently, one could blowdown 500 psi delta and the other could blowdown 10.

MR. HOFFMAN: Sure. We do send our valves offsite to the valve manufacturer for offsite refurbishment, you know, setting of those blowdown ring settings to ensure they're consistent and per the required documentation. And they also are tested offsite. And so there's quite a bit of control on the actual blowdown rings themselves.

MEMBER SKILLMAN: Thank you.

CONSULTANT WALLIS: For this feedwater line break, is offsite power available?

MR. KABADI: Right. We do that with RCPs running.

CONSULTANT WALLIS: It is available.

MR. KABADI: What's that? I didn't --

CONSULTANT WALLIS: Offsite power is available?

MR. KABADI: Yes. That's why we run the

RCPs. And Tim, we did not -- you did run and check that with loss of offsite power is non-limiting, right?

MR. LINDQUIST: Yes. This is Tim Lindquist, AREVA. Yes, we ran both cases with and without loss of offsite power.

CONSULTANT WALLIS: You did both?

MR. LINDQUIST: We did both, yes.

CONSULTANT WALLIS: That's why I was puzzled because I read the SER and it said that it was analyzed assuming offsite power was available and offsite power was not available which sounded like a logical inconsistency. It means that you did it both ways.

MR. LINDQUIST: Yes, we did.

MR. KABADI: And pump running came out limiting, yes.

MEMBER ABDEL-KHALIK: Have you also analyzed the loss of feedwater ATWS? And what is the peak RCS pressure for that event?

MR. KABADI: For ATWS we have that diverse scram system. We have it dedicated to meet that requirement for ATWS. And we just revisited and confirmed that the setpoint put on there is okay for EPU.

MEMBER ABDEL-KHALIK: So you're not required to do the loss of feedwater and pressurization ATWS events?

MR. KABADI: That is correct, because we installed that diverse scram system independent of the novel reactor trip.

MEMBER ABDEL-KHALIK: Okay, thank you.

CONSULTANT DOWNER: Said, can I ask a question? This is Tom Downer.

CHAIR BANERJEE: Go ahead.

CONSULTANT DOWNER: This is about S-RELAP5. Do you have spatial kinetics in S-RELAP5?

MR. LINDQUIST: No. For the analyses that we're talking about here it's point kinetics.

CONSULTANT DOWNER: But I'm interested in the CEA withdrawal at power conditions. For that event are you using spatial kinetics or point kinetics?

MR. LINDQUIST: It's point kinetics.

CONSULTANT DOWNER: Are you going to talk about that in the closed session?

CHAIR BANERJEE: We can.

CONSULTANT DOWNER: Okay. I'll bring it up during the closed session then.

CHAIR BANERJEE: Unless it can be answered now. Or would you rather do it during the closed session?

CONSULTANT DOWNER: Right, because I'd like to quote some specific values.

CHAIR BANERJEE: Okay.

CONSULTANT DOWNER: And talk about that. Okay?

CHAIR BANERJEE: Can we note that?

MEMBER ABDEL-KHALIK: It's two slides down. Slide 28.

CHAIR BANERJEE: Okay, hold on, Tom, and we'll see whether -- what to do.

CONSULTANT DOWNER: Okay, thanks.

CHAIR BANERJEE: Go ahead.

MR. KABADI: Okay. So this slide, the limiting events in the RCS overheating, loss of load we talked about and feed line break. Other events we do not currently have in our licensing basis, but we analyzed that to show that it was what we have done to prevent RCS subcooling loss. And we found that we can maintain subcooling days under current AFW flow that we have.

For other events that are shown here we met the requirement. There is no violation of any of the criteria.

CONSULTANT WALLIS: Are you going to talk about slide 27? Or are you going to skip through in this?

MR. KABADI: Which one?

CONSULTANT WALLIS: Twenty-seven. I thought you were just summarizing that they all met the requirements.

MR. KABADI: On the next slide. I was on slide 26. Yes, on 27 this is the overcooling. The limits are the steamline break in this category. We also -- first two events mentioned here, we did it under excess steam flow which is the increased steam flow recorded here and the inadvertent opening of safety valves. And those two meet with sufficient margin.

For the steamline break we analyze two different types of event. One is looking for the conditions prior to reactor trip to see -- to delay the reactor trip and see how high the power can go. And the second event is for the post-scram which is what happens after the reactor trips and the cooldown still continues.

CONSULTANT WALLIS: You have evaluated the temperature of the fuel, maximum temperature of the fuel and compared it with the melting temperature, right? Or you've looked to see how many of these rods melt?

MR. KABADI: That is correct. That's a part --

CONSULTANT WALLIS: Did you take account of the thermal conductivity -- when you did that?

MR. KABADI: That is correct. I was going to -- these analyses in the non-LOCA for the fuel centerline melt did take into account of TCD. Impact of TCD. And we will discuss a little bit in the closed session how that centerline melt temperature is adjusted for TCD. And that has been included in -- as part of this analysis to determine fuel centerline melting.

MEMBER SKILLMAN: In the advertent opening of the safety valve, in the second line item there, what assumption do you make regarding the total blowdown incremental pressure? This goes back to the setting of these rings. If you have one or several large safety valves open and the reaction rings are set very tightly then you can have an enormous blowdown that looks like a steamline break. And so my question is how is the setting of the relief valves addressed in that particular event?

MR. KABADI: For this event we have just

taken the max flow that one safety valve is rated at and that's what is used in this analysis. We did not count additional --

MEMBER SKILLMAN: So it's maximum flow of one safety valve.

MR. KABADI: That's correct. However, we have analyzed increase in steam flow, separate event. That covers a range of cooldowns as part of the AOO to show that we don't violate the --

MEMBER SKILLMAN: Okay, thank you.

MEMBER ARMIJO: What is the power increase in let's say the worst of these events for your peak rods? You said actually it's probably around an 11 kilowatt per foot LHGR. In this kind of an event what is the peak LHGR that you reach let's say from 11 to something?

MR. KABADI: Like for pre-scram steamline break which is mentioned here, we go as high as about 21.

MEMBER ARMIJO: In seconds?

MR. KABADI: Twenty-one kilowatt per foot at the max.

MEMBER ARMIJO: Yes, right, but that's a calculated thing. But what would you actually expect would happen? In the 21 then you're, you know, if you do that you're going to have a lot of cladding strain, you're going to have a lot of things going on. But in reality is it really that high and do you have an estimate of what that is?

MR. KABADI: I didn't understand when you said in the reality.

MEMBER ARMIJO: I know. I'm trying to say if an event like this happened.

MR. KABADI: Okay.

MEMBER ARMIJO: Okay? I know these are not reality, okay? If an event like this and you're operating. Your peak power is 11 kilowatts a foot actual power, not calculated, but to meet a regulatory requirement. What is the actual delta power? How much cladding strain do you get?

MR. KABADI: Yes, I think to answer directly your question we don't analyze for what best estimate steamline break would do. Like this one assumes that your worst rod at the highest power is in the coldest section.

MEMBER ARMIJO: Yes, I know that.

MR. KABADI: But we don't look for a realistic rod; that definitely will be much lower. But we don't calculate that.

MEMBER ARMIJO: Well, let me stay in the

mode you're in. What is your peak cladding strain? I know it's 1 percent is your acceptance criteria. What do you calculate for the peak cladding strain in this event?

MR. KABADI: When we covered the closed session we were talking about the strain, but for AOOs. That's the presentation.

MEMBER ARMIJO: You want to withhold to --

MR. KABADI: Right. But we do that for AOOs though. We don't --

MEMBER ARMIJO: Yes, I know. We're talking AOOs and I didn't see a number for peak cladding strain.

MR. KABADI: Okay. But yes, that is in the closed session. There is a section to say what the maximum cladding strain we got among all the AOOs analyzed, even after considering TCD effects.

MEMBER ARMIJO: Okay. So you'll address it in the closed session?

MR. KABADI: That is correct.

MEMBER ABDEL-KHALIK: But not for a main steamline, right?

MR. KABADI: Right. Not for steamline break, that's what I said. For AOOs we do that.

MEMBER ARMIJO: Yes. Okay, I'm still

trying to find out what your actual -- what's going to happen to your fuel when you go through one of these transients. Have you actually made an estimate of what would actually happen? Will you fail fuel? Simple question.

MR. KABADI: Yes, I think in the reality if this one considers our peak rod being in the coldest section, and if you look in the actual, if you have this type of event we will not expect many failures.

MEMBER ARMIJO: So if you went from let's say your peak rods running around 11 and it actually went up a couple of kilowatts per foot in the transient like this, you would not expect fuel failures?

MR. KABADI: That is correct and, Tim, you could add to that. The way we analyze we assume that the coldest region remains unisolated from the --

MR. LINDQUIST: Yes. This is Tim Lindquist, AREVA. In a steamline break in particular there's a number of assumptions that are made to worsen the consequences. From a system transient standpoint particularly for -- well, actually for both, but there is no assumption of mixing between the hot and cold sectors in the lower plenum and through the core and out through the core exit.

As far as the effect of the event on peak powers, there's also assumption of a worse step rod in the calculation which, you know, after scram increases the localized peaking within that region. And I guess --

MEMBER ARMIJO: So what's the delta power? Is there any number that you have?

MEMBER ABDEL-KHALIK: You don't trip on overpowering this calculated transient. You trip on something else.

MR. KABADI: From the -- I think if you look there we have two events. One is the looking at the pre-scram type.

MEMBER ABDEL-KHALIK: -- zero power steamline break.

MR. KABADI: The second portion, that does not trip on overpower.

MEMBER ABDEL-KHALIK: Right. So what is the overpower trip setpoint? Maybe that will satisfy Dr. Armijo's question.

MR. KABADI: Our overpower trip setpoint from full power is a hundred and --

MEMBER ABDEL-KHALIK: Twenty percent.

MR. KABADI: One hundred and seven percent is the tech spec.

MEMBER ARMIJO: Okay. So it's 107 percent.

MR. KABADI: Without applying any uncertainty, yes.

MEMBER ARMIJO: And you trip there. So your delta power might be the order of 1 kilowatt a foot.

MR. KABADI: Yes. Within that.

MEMBER ABDEL-KHALIK: If it were distributed uniformly.

MEMBER ARMIJO: If it were distributed uniformly and all that. Okay, thank you very much.

MR. KABADI: Next slide. These are reactivity addition events. CEA withdrawal at hot zero power. That shows sufficient margin. What we did for EPU is the CEA withdrawal at power. For the prior two EPU we analyzed it only at full power. Now we did also at part power conditions. And we found that all the limits are met. There was no violation of any criteria we have. Peak pressure is significantly below the limit and bounded by loss of load, what we presented earlier.

For CEA drop, again, there are no violations. The margin is adequate, is sufficient --

CONSULTANT WALLIS: You're again using the thermal conductivity degradation for the fuel melt?

MR. KABADI: Right. For all the non-LOCA events presented here the fuel centerline melt has taken into account TCD effects.

CHAIR BANERJEE: So Tom, you had some questions here, right?

CONSULTANT DOWNER: I'd like to just ask a little bit about your modeling of the CEA withdrawal at power. Now, you're using point kinetics which, you know, that assumes a linear reactivity insertion versus time. And in fact, you know, you can see this in Attachment 5, you see that.

My concern is that when we use a spatial kinetics model we are modeling then, let's say the reactor more realistically has like something closer to a cosine distribution axially. Then for what we get is a more than S-shaped curve than a linear curve. So, how this impacts things is because we would get, when the rod is moved to the center of the core it's going to accelerate its contribution, you know, the reactivity contribution.

And this gets my attention because if you look at the minimum DNBR you predict you're going to see it at 90 seconds which is at the very end of this event when in fact, you know, if you use a more realistic spatial model it's going to happen sooner. And so you can see the values in the slide, 1.239 is what you're predicting and that's only about 6 percent away from, you know, the 1.164.

So my question is how did you convince yourself that your point kinetics modeling of this event in S-RELAP5 is conservative.

MR. KABADI: Let me try to answer that and then Tim, you could help. I think S-RELAP5 does the CEA withdrawal calculations with this reactivity addition and generates all the state points that eventually fit into your TNH and the neutronics codes, right? There in that analysis you bias all these parameters. Can you, Tim, just add what on this analysis is done subsequently on S-RELAP5?

MR. LINDQUIST: Subsequent to the S-RELAP5? I think I'll let Chris talk to that.

MR. ALLISON: This is Chris Allison from AREVA. As Tim noted, the boundary conditions are generated by S-RELAP5 in a conservative method using the point kinetics. And then the core TH method applies those in a static form looking at individual time steps as the transient progresses, and applies biases on the operating parameters in a deterministic stackup to get them the lowest DNBR that can be achieved during the event.

The neutronics information is generated in terms of the axial power shape that you would see in the event also from a static perspective. And what we do is we generate a whole range of axial power shapes based on xenon transients that are very extreme in the direct axial power shapes beyond the limits that the trip functions would allow.

And what we do is then we take the most limiting axial power shape that we find from that series of xenon transients and we apply that to the event. And that event, excuse me, that axial shape is one that's actually outside of the allowable trip function limits. And so through that combination we assure a conservative DNBR prediction for the event.

CONSULTANT DOWNER: Chris, could I ask you -- maybe it's best over break, but if you look at the Figure 2854-14 in Attachment 5, my concern is that the reactivity insertion is very strictly linear. And what I know is physical is more of an S-shaped function. And so that's, you know, what concerns me. It's not the axial power shape you're using in your subchannel code to predict DNBR. What concerns me is the reactivity insertion, if that is conservative.

Maybe in the closed session you or someone else can address that.

MR. ALLISON: Okay. So your main concern is whether the peak power prediction from S-RELAP5 is really conservative?

CONSULTANT DOWNER: Well, first the reactivity insertion and then, yes, then the peak power prediction. But it's driven by the reactivity which in that figure is shown as strictly linear which I think is not physical.

MR. ALLISON: Right. Is the figure that you're referring to, is that a CEA withdrawal from 100 percent power?

CONSULTANT DOWNER: Yes.

MR. ALLISON: In that case the rods would only be parked at the 100 percent PDIL position. So there's actually a very small insertion distance there that the rods are being withdrawn from. But yes, I think we can discuss more later in the meeting if not during the break.

CONSULTANT DOWNER: Okay, I appreciate that. Thank you.

CHAIR BANERJEE: Okay, so we'll note that this will be an item, Weidong, that we'll take up. Are there any other points, Tom, on this slide, slide

28? You have the slides, right?

CONSULTANT DOWNER: Right, I'm looking right at it and everything else is fine. I'm, again, the 6 percent margin there on the DNBR, that's the one that just caught my attention.

CONSULTANT BONACA: The only comment I have is on the enthalpy of 200 calories per gram. Just a curiosity. In the application was a discussion of 280 versus 240.

MR. KABADI: Yes, I think our current design basis has 280. That's in the current design basis. And the subsequent RAIs during the review process with the staff, we conservatively right now use in our analysis 200 although the SRP allows up to 230. So this is a little conservative number we tried to do that which has additional margin compared to 230 which is in the SRP.

CONSULTANT BONACA: Yes. I just bring it up because we have seen it coming down for the reasons we know. And you know, that's one more step down.

MR. KABADI: Right. Right. We took some additional margin there. That's correct.

MEMBER ARMIJO: Let me ask just a broad question. Have you ever had any one of these AOOs occur in your plant?

MR. KABADI: We do have loss of load once, it has happened. I don't know how often, but yes. We do have -- what was it, Jack? Complete loss of load whenever we had that? Maybe once or whatever it is. Yes, we did have loss of load when the safety is open.

MEMBER ARMIJO: Okay. Have you ever had a CEA withdrawal of power?

MR. KABADI: Not at St. Lucie to my knowledge.

MEMBER ARMIJO: Good. Happy to hear that.

MR. KABADI: I don't recall. Well again, wait, we do have CEA drop. Not -- if you look in the history of the plant we do sometimes drop one rod. And then we have tech specs to get the rod out and then reduce power and we follow that -- yes. The CEA drop is another one we have seen.

MEMBER ARMIJO: Okay, thank you.

CHAIR BANERJEE: Okay, let's move on.

MR. KABADI: Yes, in the boron dilution there is no change based on the current design basis. We meet the acceptance criteria for all the modes seen at the current analysis there.

In the second event, that inadvertent ECCS or CVCS, that's a new event done for EPU. We do not have that in the current licensing basis. We are adding charging pumps to the ECCS which we did not have before.

And based on that, an inadvertent ASI will create or will have charging on and that needs to be analyzed. So, we did analyze that following the same -- I mean, the SRP guidelines and we do meet the requirement that operators will have sufficient time to stop that dilution of the RCS mass addition which is mainly charging coming on and we assume conservatively letdown goes to zero. So that's a new event we put into our EPU analysis.

MEMBER SKILLMAN: What initiated the addition of the charging pumps?

MR. KABADI: Just an inadvertent ASI. Just a false signal that starts the SI pumps. And since our HPCI pumps are low-head they will not deliver anything, so only thing is we assume that all the charging pumps come on. We maximize the flow that can go into that.

MEMBER SKILLMAN: Are those positive displacement pumps?

MR. KABADI: Yes, those are positive displacement pumps.

MEMBER SKILLMAN: Thank you.

MEMBER ABDEL-KHALIK: Your pressurizer

volume is, what, 1,500 cubic feet?

MR. KABADI: A little over 15 but yes. And the last event in this category, the inadvertent opening of PORV. We do have that event in our current licensing basis analyzed for DNB. And we did that, and that shows a sufficient margin for that.

However, during the review additional concerns came about the pressurizer fill for this event. And we analyzed that also to see what time the pressurizer would get filled if no action is taken. And we find that the time for operator reaction for this is significantly small. That is, numbers in the analysis looks like I have adequately covered that operator time.

MEMBER ABDEL-KHALIK: Now, with the increase in T-ave at what pressure would the RCS stabilize ave after you open the pressurizer PORVs and how does that pressure compare to the shutoff head of your safety injection pump?

MR. KABADI: In this analysis, and Tim, you can add to that, we do get -- if you don't do any operator actions and you do get ASI pressure does hit the SI setpoint. Now I don't know whether it goes below the SI head. Do you?

MEMBER ABDEL-KHALIK: So the pressure goes below?

MR. KABADI: Our safety injection signal is about 1,600 psig. But our pumps do not inject till the pressure goes below something like 1,200 or something like that.

MEMBER ABDEL-KHALIK: What's the saturation pressure at 570, whatever your new T-ave is?

MR. BROWN: This is Dave Brown from FPL. The high-pressure safety injection pumps start injecting right about 1,200 pounds.

MEMBER ABDEL-KHALIK: Right.

MR. BROWN: Okay. So as they're coming down, as we pass through 1,200 pounds they would start injecting.

MEMBER ABDEL-KHALIK: Well, but the system pressure will stabilize initially because it's being held up by the high T-ave.

MR. BROWN: That is correct.

MEMBER ABDEL-KHALIK: So, where is that pressure compared to the shutoff head of your high-head safety injection pump?

MR. BROWN: Well, for the high-pressure safety, I don't know what that particular pressure is. That's something that we would have to look up.

MEMBER ABDEL-KHALIK: AREVA knows that.

MR. LINDQUIST: I don't know offhand.

MR. KABADI: In this, the analysis which is done here that shows 7 minutes, the PORVs remain open so it continuously depressurizes.

MEMBER ABDEL-KHALIK: Right, but it's going to hold up because the system is going to reach T-ave and it's going to saturate.

MR. KABADI: Saturation, yes. We can -- I think, I don't know whether we have that plot in the submittal. I don't recall. If the best plot is there then that will show that.

MEMBER ABDEL-KHALIK: Could you find that out and let us know later, please?

MR. KABADI: I'll look for that.

MEMBER ABDEL-KHALIK: Thank you.

MEMBER ARMIJO: We should keep going.

MR. KABADI: Yes. Differential of the small break LOCA analysis. We'll cover the TCD impact in the closed session this afternoon, but all the analysis we did, small break, large break and the non-LOCA, wherever the TCD had an impact we did include to that small break. We did not see any impact due to TCD.

Now, this slide shows the differences in some of the parameters for the pre-EPU conditions and the EPU conditions. You can see that the power level went up, the kilowatt per foot, 15 to 14.7. We reduced the radial peaking factor. And the tube plugging level as I mentioned before reduced 10 percent. And the last item, and that's the one which provided some margin for a little larger breaks, the SIT pressure minimum was moved from 200 to 230 psig.

CONSULTANT WALLIS: You did something also about loop-seal clearing, didn't you?

MR. KABADI: Yes. I think that's the change in the methodology about how the loop-seals clear.

CONSULTANT WALLIS: Can you explain that?

MR. KABADI: I think that may be AREVA proprietary, so probably if we need to discuss that we can --

CONSULTANT WALLIS: Later?

MR. KABADI: -- cover that. That was one item not on the list.

CONSULTANT WALLIS: It's proprietary? I don't know why because I mean a loop-seal clears or it doesn't.

MR. KABADI: Yes, but I think in their submittal -- Tim, can you respond to that? I think the loop-seal clearing is proprietary.

MR. LINDQUIST: Yes, this is Tim Lindquist from AREVA. I think we prefer to talk about that over the closed session.

CONSULTANT WALLIS: Okay.

MR. KABADI: Okay, the next slide shows the results of the small break LOCA. And the EPU we get to 1,807 as a peak clad temperature. And the oxidations are also well below the limit.

CONSULTANT WALLIS: What is the range of break sizes that you looked at?

MR. KABADI: The break sizes go from about 3 inches to all the way 7 inches. Tim, do you have that number?

MR. LINDQUIST: I don't have the number. It's on the order of that range.

CONSULTANT WALLIS: This sort of puzzled me. In the large break LOCA the break size goes from 26.7 percent to 100 percent of double-ended guillotine large break. That would seem to go from 16 inches to whatever the punch size, that sort of range. Seemed to be a gap in the pipe sizes that we're investigating.

MR. KABADI: Yes, I think that is something if you look that's been in the history of the LOCA. You analyze small breaks and then go to large breaks.

CONSULTANT WALLIS: Intermediate breaks don't get analyzed at all.

MR. KABADI: Yes, but as part of this we did analyze SIT line break which is the 12 inch, just to show --

CONSULTANT WALLIS: You did do that.

MR. KABADI: And then that shows -- because what happens is once you go to the extreme of large break or to the other end of small break, other breaks in the safety injection tanks and all are --

CONSULTANT WALLIS: I think it would be good to put that in because otherwise the impression is given that there's a break in the break size spectrum.

MR. KABADI: We put in the staff review.

CHAIR BANERJEE: There was an RAI on this.

MR. KABADI: We were asked to analyze an SIT line break which is a 12 inch.

CONSULTANT WALLIS: Okay, so it was covered.

MR. KABADI: That was provided and analyzed.

CONSULTANT WALLIS: And then there's some kind of a plot of versus break size or something?

MR. KABADI: It shows a very low pressure. I mean, the PCTs. Once the break size goes about the break size where the SITs come on till you go to a real large break.

CONSULTANT WALLIS: And the physics changes, yes.

MR. KABADI: Right. And the 12 inch line showed that the SIT comes in the range of about 1,100 or so.

CHAIR BANERJEE: This is going to be very, very sensitive to loop-seal clearing and things, right?

CONSULTANT WALLIS: I believe I asked about this.

CHAIR BANERJEE: Yes, I was out.

CONSULTANT WALLIS: -- the proprietary session.

CHAIR BANERJEE: Sorry?

CONSULTANT WALLIS: That's for the proprietary session.

CHAIR BANERJEE: Okay, okay.

MR. KABADI: Right. And we can discuss that later.

CHAIR BANERJEE: Yes.

MEMBER ABDEL-KHALIK: Could you explain why these results are not impacted by thermal conductivity degradation?

MR. KABADI: It's mainly these -- small break LOCA PCT comes way down in the timing where the decay heat plays a more significant role. And the initial little -- the higher stored energy that does not affect what happens. Something like I think these PCTs come in the range of about 2,000 seconds. And the initial stored energy initially gets dissipated through the steam generators and does not have any significant impact later on. That is the trend seen in not only for St. Lucie but it does not significantly impact that.

MEMBER ABDEL-KHALIK: But that sort of depends on how small is a small break, right? Because that will impact your time line.

MR. KABADI: Right. Once your break goes to a size that falls into this category where we have a complete uncovery of the core and all, then it will be bounded by large break where we did account for the TCDs. And those would provide other extreme. We have the only PCT type within the first 100 seconds or whatever coming in.

MEMBER ABDEL-KHALIK: So this is just

based on intuition that because of the long time of the transient that, you know, initial stored energy doesn't play much of a role and therefore --

MR. KABADI: That is correct.

MEMBER ABDEL-KHALIK: Rather than an actual calculation of --

MR. KABADI: Right. We have not -- that is correct. We have not done actual calculations for these. That is correct, we have not.

MR. DUNN: This is Bert Dunn. Can I add something?

MR. KABADI: Yes, go ahead.

MR. DUNN: Thank you. Bert Dunn, AREVA. The reactor coolant pumps are operative during the first several seconds of a small break LOCA. Typically coast-down is about 100 seconds. So whether you have power or not you have a force flow situation during the early portion of the accident. That transfers a significant amount of the stored energy, practically all the stored energy, out of the system through the liquid into the steam generators. And then after about 50 to 60 seconds you operate on a decay heat, a delta T from the fuel pellet across the cladding to the coolant. That's determined by the decay heat. And that's the primary reason.

And so -- and that's operative up to the transition to the -- outside of the small break range. If we look at breaks in the 10 inch area we will see that there are a good -- that the cladding temperature occurs out past 100 seconds, usually probably past 200 seconds. So it's not just intuition, it is an observation from calculations.

CHAIR BANERJEE: Can I ask how do you turn the temperature at 1,800? How is it turned? You can slowly do that one step at a time. How does it turn?

MR. KABADI: You mean what phenomena turns it? Yes, in this -- that's where the SIT pressure. If you look at the different break sizes the breaks where this 1,800 is just when the SITs come on. And that turns it.

CHAIR BANERJEE: So you have to remove some energy.

MR. KABADI: Right.

CHAIR BANERJEE: But do you think there is more stored energy would degrade tunnel conductor really at 1,800 degrees or not? Or it doesn't have any effect? Is there any fuel temperature profile at all? Or is it such a uniform --

MR. DUNN: There is probably a temperature profile in the pellet. It would probably be different with thermal conductivity degradation than it would be without it. However, the cladding temperature is controlled by the ability of the cladding to release energy from the surface of the cladding to the coolant. And that's the same, that's the decay heat that has to be transferred there, regardless of what the temperature is inside the pellet.

CHAIR BANERJEE: I think by and large we would agree that, you know, the effect of thermal conductivity degradation for a small break wouldn't be very significant. But without actually doing a calculation it's hard to answer Said's question I would say which is what is the effect. It could be as small as 5 degrees or 50 degrees or something. I don't know what it would be. That's the issue.

MR. DUNN: Bert Dunn again. We have done calculations on other plants.

CHAIR BANERJEE: Right.

MR. DUNN: That would support your opinion. If we want to talk about 10 degrees or something like that I'm not going to argue.

CHAIR BANERJEE: Yes. I don't know what is the magnitude that you found.

MR. DUNN: For this --

CHAIR BANERJEE: Not this specific plant, but what have you found with other plants?

MR. DUNN: I have done a plant with a 600 degree change in initial fuel temperature for a small break that occurred in this approximate time frame range with about a 15 degree effect on peak cladding temperature.

CHAIR BANERJEE: Okay.

MR. DUNN: And the thermal conductivity degradation here doesn't even come close to that temperature change.

CHAIR BANERJEE: It would be in the teens.

MEMBER ABDEL-KHALIK: What are the reactor coolant pump trip criteria for a small break LOCA?

MR. HORTON: Todd Horton, FPL. I oversee the operating curves. Once we enter the standard post-trip actions if we receive a safety injection signal the operating procedures direct the crews to trip one reactor coolant pump in each operating room. So at that point we have two pumps running.

MEMBER ABDEL-KHALIK: Okay.

MR. KABADI: Okay, I think that was the last slide.

CHAIR BANERJEE: So, what we could do is I don't think we need to go back, right? We could take a break and then I guess after lunch the staff will come on, right?

MR. WANG: After lunch the staff will come on, but --

CHAIR BANERJEE: But you have an informal meeting with the staff.

MR. WANG: Right.

CHAIR BANERJEE: With the subcommittee.

MR. WANG: Here, right.

CHAIR BANERJEE: Yes. So, could we do this that we take a 20-minute break and meet with the -- if it suits the staff at 12 o'clock here? For the informal meeting, or 12:15, whatever the staff wants. And then we can go back to the agenda at 1 o'clock. Is that okay? Does that work?

MEMBER ABDEL-KHALIK: Okay. You want to reconvene at 1 o'clock?

CHAIR BANERJEE: No, we'll reconvene here at noon, 20 to 12. I mean at 12.

MEMBER ABDEL-KHALIK: At 12.

CHAIR BANERJEE: Only the subcommittee members and the staff. Nobody else.

MEMBER ABDEL-KHALIK: Oh, I see.

CHAIR BANERJEE: So, not the applicant or anybody, only the staff because the staff may share information with us which may be only limited.

MEMBER ABDEL-KHALIK: Is this meeting going to be on the record, Mr. Chairman?

CHAIR BANERJEE: It was supposed to be an informal meeting.

MR. WANG: It's not going to be on the record.

CHAIR BANERJEE: It wouldn't be on the record. It's just informational.

MEMBER ABDEL-KHALIK: Okay.

CHAIR BANERJEE: That's all. It's not decisional in any way. Unless the staff wants it on the record. Yes.

CONSULTANT WALLIS: Sanjoy?

CHAIR BANERJEE: All right?

CONSULTANT WALLIS: We have to go away and come back. The staff isn't ready now?

MEMBER REMPE: Let's do it now because I have another meeting.

CHAIR BANERJEE: Well, if the staff is ready now we could do it and just defer our lunch till we're done. That would also suit. That's no problem. Okay, so I'm going to go off the record now, okay? We'll reconvene at 1 o'clock and then we'll go on the record. We're off the record.

(Whereupon, the foregoing matter went off the record at 11:41 a.m. and went back on the record at 1:00 p.m.)

CHAIR BANERJEE: Back in session. I'll hand it over to, who is it, Jennifer? Are you going to lead off?

MS. GALL: Sam is first.

CHAIR BANERJEE: Oh, Sam. All right.

MR. MIRANDA: Good afternoon. My name is Sam Miranda. I'm the reviewer in the Reactor Systems Branch in NRR and with me is Jennifer Gall, also a reviewer at the Reactor Systems Branch. I will talk a little bit about the non-LOCA safety analyses that were reviewed for St. Lucie Unit 1. And Jennifer will follow up with loss-of-coolant accident.

And I selected a few events that had particular unique aspects to St. Lucie Unit 1. And I'll describe that in this order: feed line break and various mass addition events.

You may notice that in the mass addition events I've included the inadvertent opening of a PORV. This event is not listed as a mass addition event in Regulatory Guide 1.70 which is the standard format and content for safety analysis reports.

Inadvertent opening of a PORV is analyzed as an event that can degrade thermal margin. It's there to show that the plant is adequately protected against DNB and typically this event is analyzed until the time of reactor trip, demonstrating that DNB doesn't occur.

However, if we continue to look at this event past the time of reactor trip we will find that the continuing depressurization will eventually lead to a safety injection signal. And then that could fill the pressurizer. This is not an inadvertent safety injection. This is a legitimate safety injection and it could eventually fill the pressurizer, cause the PORV to open and if it passes water the PORV could stick open.

The first event I'll talk about is the feed line break. In their application FPL indicated that the feed line break is in their licensing basis defined as a cooldown event. This was unique to St. Lucie 1. The feed line break could be either a cooldown or heatup event depending upon principally the quality of the break flow. If the quality is very low, if you have dry steam it's basically a steamline break and that's the cooldown event. If there's a lot of water entrainment then it's a heatup event, it's a loss of heat sink.

And the feed line break is analyzed as a heatup event. It's listed as such in Reg Guide 1.70 and the guidance for reviewers in the Standard Review Plan is to look at it as a heatup event. So, we asked the licensee, FP&L, to provide us with an analysis of the feed line break as a heatup event. And we received this analysis and we audited it during our audit of January 30 and 31st.

The results were acceptable. They showed that the RCS remained subcooled throughout the event. They did two cases with or without offsite power. The case with offsite power approach -- had the closest approach to saturation in the reactor coolant system hot leg.

We also looked at the inadvertent actuation of ECCS. This event, this is the mass addition event that causes licensees the most trouble mainly because they don't have enough time to turn off the safety injection before the pressurizer can fill. And if it does fill, as I stated earlier, the valve can stick open and this would create a small break LOCA at the top of the pressurizer. And this would violate one of the acceptance criteria that licensees commit to comply with in their licensing bases, that an event cannot propagate into a more serious event without other faults occurring independently.

MEMBER ABDEL-KHALIK: What if the PORVs were qualified?

MR. MIRANDA: If they were qualified then they could be used to mitigate the event. They would open, pass water and when necessary would recede.

MEMBER SKILLMAN: For this event, Sam, are the code valves on the pressurizer threatened?

MR. MIRANDA: If the PORVs open the code valves should not open.

MEMBER SKILLMAN: Let me ask it differently. Is the volumetric flow rate of the ECCS system great enough to overwhelm both the stuck-open PORV and the codes?

MR. MIRANDA: No. And you'll see that later in these slides.

MEMBER SKILLMAN: Okay. Thank you, Sam.

MR. MIRANDA: When we received the application from FP&L there was one paragraph in the section dealing with the inadvertent ECCS actuation. It's one of the events that's required for inclusion in an FSAR according to Reg Guide 1.70. And their entry was simply that we really don't need to analyze this event since the shutoff head of the SI pumps is too low to pump against the nominal RCS pressure.

And normally we would accept that, except in this case the application also included a request to revise the tech specs in order to include the charging pumps in the ECCS. So they have three positive displacement charging pumps which have a total flow of about 147 gpm. And now they are actuated along with the SI pumps from a safety injection signal.

And this is the criterion that has to be met that they can't -- a Condition II event cannot become a Condition III or IV event. And this is something that the NRC took note of in 2005 with a RIS reminding licensees that they have to meet this criterion because it's in their licensing basis.

CONSULTANT BONACA: From the charging flow it's quite low, is it?

MR. MIRANDA: Yes.

CONSULTANT BONACA: What is the gpm per pump?

MR. MIRANDA: Forty-nine gpm per pump, yes.

CONSULTANT BONACA: And that creates the concern.

MR. MIRANDA: Yes. Yes. Now, when FP&L performed the analysis of the inadvertent actuation of ECCS they also had to do an analysis of the CVCS malfunction. And they were able to combine the two events into one conservative case. And this was also an unusual occurrence mainly because they don't have a safety -- they don't have a reactor trip signal generated by the safety injection signal. That's what we face in most of these plants.

With a Combustion plant we don't have that. So, they would have the inadvertent ECCS actuation occurring at full power and they would have to wait for a reactor trip signal. Pressurizer high level might be one of them. The same thing with the CVCS malfunction. They would have to wait for a reactor trip signal. So if they take the maximum flow possible which is all three positive displacement pumps operating at the same time basically it converges into one case and this is the case that they performed. And they were able to show that it would take about 11 minutes to fill the pressurizer. And this is accepted by the staff as being sufficient time for the operator to remedy the situation.

CHAIR BANERJEE: So these pumps were added just to help the -- also to help the ECCS system, add pressure? What was the reason they were added?

MR. MIRANDA: I don't know the reason. They didn't tell me the reason they were added. Yes, they do help the ECCS.

CHAIR BANERJEE: One reason, anyway.

MR. MIRANDA: That would be a good assumption, yes.

CHAIR BANERJEE: Yes.

MEMBER RAY: They were added to the ECCS, not added to the plant.

MR. MIRANDA: Right.

MEMBER RAY: And they are credited to the ECCS.

CHAIR BANERJEE: Yes.

MR. MIRANDA: They were always there. But now they're actually --

MEMBER RAY: I began to get the feeling you thought they added the pumps.

CHAIR BANERJEE: Yes, sorry. Okay. So they were always there for charging.

MEMBER RAY: Yes, yes.

CHAIR BANERJEE: And they were now --

MR. MIRANDA: Now they're part of the SI sequence.

MR. KABADI: This is Jay Kabadi, FPL. Our charging system did not -- does not require any change. There were always designed safety grade and all, but they were not put in the tech specs. We are just adding that in the tech specs.

CHAIR BANERJEE: So, now they have put the ECCS --

MEMBER ARMIJO: In a regulatory sense.

CHAIR BANERJEE: Yes. Do they add a lot?

MR. KABADI: Yes, depending on the break size I think in my presentation we mentioned that there are some break sizes which depend on the injection from the HPCI flow and the charging flow. When the pressure is a little high charging flow becomes a quite a big portion of the flow getting into the RCS.

MR. HORTON: Todd Horton, FPL. Just to clarify, the charging pumps have always received the safety injection signal.

CHAIR BANERJEE: But they have always received.

MR. HORTON: Yes, they have always received the safety injection signal. We've just credited now for the ECCS tech spec and it's now credited. It's always had its own separate tech spec in tech specs and it's always -- the three pumps have always received the safety injection signal.

MR. MIRANDA: Well, then I would have to ask why did we have that entry in the application?

That you don't have to do the inadvertent actuation of ECCS. We'll get an answer here.

MS. ABBOTT: This is Liz Abbott from FPL. The entry in the application is because those pumps are now credited to mitigate an event. In the past although they were there and present and able to mitigate an event they were not credited in the accident analysis.

CHAIR BANERJEE: Well, for the real hazard of filling the pressurizer they were always there, right?

MR. MIRANDA: They were always there and they should have been analyzed for whether they were credited or not. Because this is not a situation where you're mitigating an event, this is an initiating event.

MEMBER SKILLMAN: What procedure changes have been made to protect this 11-minute operator action required time?

MR. MIRANDA: They do have EMPs that they have to follow and operators are tested, time-tested against this operating procedure so that they can meet a time like this.

MR. HORTON: Yes, Todd Horton, FPL. We do have abnormal operating procedures for this exact condition and one of the actions is for the operators to take control of the charging pumps.

MEMBER SKILLMAN: How do they know when to take action?

MR. HORTON: One of the first indicators will have this condition, will be a high pressurizer level alarm which is based off a deviation from setpoint which is actually a very small number. If I remember correctly it's 3 to 5 percent deviation from setpoint. And then we also have specific alarms for the safety injection signal. That is, an entry condition into that procedure and as soon as we enter that procedure has -- directs the operator to take those actions.

MEMBER SKILLMAN: Okay, thank you.

MEMBER ABDEL-KHALIK: Did you just say that the high pressurizer level alarm is only a few percent higher than the normal pressurizer level?

MR. HORTON: We have multiple inputs into the high pressurizer level alarm. One is just a straight number, and then we also have a deviation. Based on the power level we have a setpoint that's calculated --

MEMBER ABDEL-KHALIK: And that deviation is only a few percent?

MR. HORTON: That's right.

MEMBER ABDEL-KHALIK: From the normal pressurizer level.

MR. HORTON: That's correct.

MR. MIRANDA: Okay. Next slide. So, this is the new mass addition event that we've discovered recently. And this was also covered for the Turkey Point EPU. And in the Turkey Point EPU part of the audit that we did there was to go to Turkey Point and observe the operators deal with an inadvertent opening of a PORV.

And in that case we observed the operator go through a very quick procedure which did not involve looking up any procedures. It was a prompt action. They checked the pressurizer pressure, they checked some other things on the control board. The whole operation took about 9 seconds. They quit the PORV. And in the event that the PORV won't close there's also the manual block valve.

For St. Lucie we looked at the analysis provided by the licensee and we observed that if no operator action is taken a safety injection signal is generated in about 107 seconds, less than 2 minutes. And again, if no operator action is taken the pressurizer will fill in 7 and a half -- less than 7 and a half minutes.

Now, this is getting difficult to justify. And this is solely on the action of the charging pumps. The safety injection pumps still cannot pump against the RCS back-pressure. So the charging pumps, the 149, 147 gpm is sufficient to pressurize the system and open the PORVs.

MEMBER SKILLMAN: How could the operators know the PORV is stuck open or the PORV is open?

MR. MIRANDA: Well, there is an alarm for an open PORV.

MEMBER SKILLMAN: Other plants have had an alarm on a PORV too and it wasn't too accurate.

MR. MIRANDA: And judging whether the PORV is stuck is another question. You have to look at the pressurizer pressure and see whether or not the PORV ought to be open at that pressure.

MR. HORTON: This is Todd Horton, FPL. We do have specific alarms. This is one of those conditions that we train on regularly with the operating crews. There is this specific alarm that the operators identify associated with a PORV and the immediate action is they verify, validate pressurizer pressure and the PORV position. And then they have immediate actions they're required to take in the event that we have a PORV that's inadvertently open to close the PORV. That is something we routinely train on. There are a couple of conditions that we specifically look for post-trip and online. Questions?

MEMBER SKILLMAN: No, thank you. Thank you.

MR. MIRANDA: Okay, next slide. This is the transient I was talking about. We have the PORV activate and this is the pressurizer level, pressurizer liquid volume. And the volume would, it goes down as expected. And eventually, down at the bottom, that little trough there? That's where the safety injection signal is generated. And the pressurizer level increases solely due to the flow contributed by the charging pumps. And it does fill in less than 7 and a half seconds.

MEMBER ARMIJO: Minutes.

MR. MIRANDA: Minutes, sorry. Now, my reasoning in the Safety Evaluation for this event was, well, if the operator does nothing -- the operator can do several things. First of all, he closes the PORV. We assume that the operator can do it in 9 seconds but 9 seconds seems to be a bit optimistic. Suppose we say 90 seconds. If the operator closes the PORV at any time before 107 seconds when the safety injection signal is generated then the transient is over.

If the operator is a little bit slow and doesn't close the PORV until after the safety injection signal is generated, say 2 or 3 minutes, then basically this resembles an inadvertent SI actuation where the operator now has two actions to perform. He needs to close the PORV and he needs to shut down the safety injection system, and that takes a lot longer than 9 seconds.

However, as we see here, the pressurizer level has dropped. So, inadvertent safety injection actuation that we've seen earlier which took 11 minutes from nominal -- from the beginning condition of nominal level, it now is longer. It could be, I don't know, 12, 13, 14 minutes. So that 7 and a half minute pressurizer fill time is a little bit conservative. So, I was able to accept that for this case, for the St. Lucie case, and principally the reason is that -- the low flow, 147 gpm from the charging pumps only.

Now, if this were another plant with centrifugal charging pumps, for example, a Westinghouse plant, this pressurizer fill time would be much shorter than 7 and a half minutes. It would be more like 2 or 3 minutes. And we have -- we're planning to deal with that issue on a generic basis.

So, as I said earlier, we did have an audit done at AREVA in January. And the principal areas that we looked into during that audit were the feed line break where we looked at the analysis that was performed. And discussed the inadvertent opening of a PORV. And we looked at this combined analysis of the CVCS, the malfunction and the inadvertent SI actuation.

We also discussed the loss of electrical load. And in this case we had a question regarding the reactor trip signal that was credited in that analysis. There are two loss of load analyses that we expect to see. One is the FSAR analysis where the first reactor trip signal is accepted as the mitigating signal, and then there's another analysis that's described in Section 5.2.2 of the Standard Review Plan. And this one is -- this one requires the reactor trip to occur on the second safety grade signal. So this was the analysis that we were looking for. And during the audit they presented that analysis and that was the result that you saw this morning of 2,744 psia.

So, at this point I'd like to turn it

over, unless there are any questions, I'd like to turn it over to Jennifer Gall for the large break.

MEMBER ABDEL-KHALIK: On the previous slide what do you mean by the word "realistic?" In the last bullet. What does that mean?

MR. PARKS: This is Ben Parks from the NRR staff. "Realistic" is a trade name that AREVA uses, that's what they call their method. So, by comparison another vendor calls it "best estimate" and the two are used in the NRC's regulatory guidance interchangeably. It conveys the same idea.

MEMBER ABDEL-KHALIK: Okay.

MS. GALL: All right, I did the LOCA review. I'll talk about the realistic large break. The licensee implemented EMF-2103. That's the AREVA best estimate LOCA methodology.

Since its approval, NRC staff has identified some certain modeling assumptions that are not suitable for demonstrating compliance with the 50.46 requirements. And so the licensee has addressed those issues by providing plant-specific analysis that are more conservative than the currently approved version. And I'll go into more detail about some of those specific assumptions.

For the small break, they used EMF-2328.

Licensee discussed earlier somewhat about the small break LOCA, but some of the departures from the approved method are the loop-seal clearing to be more reflective of experimental data. There is additional break spectrum detail as well as they provided an SIT line break analysis.

CONSULTANT WALLIS: What does this additional break spectrum detail mean? Are you going to get into that?

MS. GALL: Yes.

CONSULTANT WALLIS: And does this cover the 12 inch break which they mentioned earlier that sort of -- there's a hole between the large break and the small break. Did they discuss the one that's sitting between that they did at all?

MS. GALL: Is that the SIT line break, the 11?

CONSULTANT WALLIS: You asked them to do that?

MS. GALL: Yes.

CONSULTANT WALLIS: Does that use the small break method?

MS. GALL: Yes.

CONSULTANT WALLIS: Okay.

MS. GALL: So, for the large break

realistic method some of the modeling assumptions that are different from the approved method. The power level and decay heat uncertainty are not sampled any longer. Bounding models are used. In the original approved method the power level was sampled so you could have ended up with a power level lower than the 3029.1. So now it's always assumed to be 3029.1.

And the decay heat is now set to the 1979 ANS standard for decay heat. And they -- we audited this and they provided some RAI responses to show that the infinite line bounds all of the other standard lines that include uncertainties. So, the line that they're using accounts for uncertainties for decay heat.

The rod quench conditions were also modified. The original approved method does not require the void fraction to be less than 0.95, it only required the cladding temperature to be less than the minimum temperature for film boiling heat transfer. And now both of those are required for rod quench.

And then thermal conductivity degradation. AREVA, after the Information Notice in 2009 incorporated the polynomial transformation to fuel centerline temperature to account for TCD effects.

And that will be discussed more in the closed session.

So, part of the review that we did, we looked at the range parameters and looked for trends. And that was a large part of the audit that we did was discussing those. And the conclusions we drew from our review are that they do meet the 50.46 requirements and the evaluation model they used was more conservative than the NRC-approved model.

CONSULTANT WALLIS: So it's supposed to be realistic. So how can it be more conservative and realistic?

MS. GALL: Well, the -- it's more conservative in the power assumptions.

CONSULTANT WALLIS: It's realistic modified to be conservative, isn't it?

MR. PARKS: This is Ben Parks from the NRR staff again. In some cases we, subsequent to approving AREVA's model we questioned the appropriateness of one or two of their correlations or models that are in the S-RELAP5 code and their applicability to the -- basically the benchmarking data that the NRC and other people sponsored the research on which realistic rules and methods were based.

And we asked them to sort of penalize

those models so that the modeling application winds up being a little bit more conservative. So, as a whole its approach is supposed to be realistic and is intended to provide a realistic and you know, the upper tolerance limit of the distribution of realistic predictions of the emergency core cooling system performance. In some cases where we think that the data might be a little bit more spread they tend to make some bounding assumptions instead.

CONSULTANT WALLIS: I think when I read this, I couldn't see that this was a 95/95. I don't think he even said that. It just said it's realistic. This is a realistic statistical approach.

MR. PARKS: Yes sir, yes it is.

CONSULTANT WALLIS: And it looks for a 95/95 upper limit. And also gives you on the way an average. It gives you a mean or a best estimate.

MR. PARKS: Right. I believe the licensee's material has that either median or a mean case of the 59. I think we have that data as part of our review.

CONSULTANT WALLIS: Your SER didn't tell me that unless I missed something. It just said realistic and I couldn't tell whether it was 95/95 or something else.

MR. PARKS: We will add some clarity to the SER.

CONSULTANT WALLIS: So where was the mean? Where was the best estimate?

MS. GALL: I'd have to go look.

CONSULTANT WALLIS: Just look at the top one? You don't look at the details of the distribution or anything, just look at the 95/95 value?

MS. GALL: I don't recall off the top of my head, but we looked at -- we generated some plots of PCT versus various inputs and results. So, we looked at the range of the results and the inputs.

CONSULTANT WALLIS: Then could you from that detect under which conditions you got the highest PCT?

MS. GALL: Yes, the highest --

CONSULTANT WALLIS: Could you sort of explain what led to the highest PCT? What condition?

MR. KABADI: This is Jay Kabadi from FPL. They did do the -- in the statistical analysis provided the mean value. The limiting, the 95/95 was 1667 and the 50th percentile was 1492.

CONSULTANT WALLIS: Fourteen ninety-two. Easy to remember.

MR. ULSES: This is Anthony Ulses, the branch chief of the Reactor Systems Branch. I think we may be touching on some proprietary information, Dr. Wallis, so I propose that if it's okay if we push it off --

CONSULTANT WALLIS: We'll get to this.

MR. ULSES: -- until closed session.

CONSULTANT WALLIS: -- what combination -- of what combination of these various statistical parameters led to the highest temperature. That would be of interest.

MR. ULSES: Okay.

MEMBER ABDEL-KHALIK: You assume local oxidation values. Are these the oxidation values associated with the transient itself, or do they also include the pre-transient oxidation levels?

MS. GALL: I believe they include the pre-transient oxidation levels, but I'd have to check.

MEMBER ABDEL-KHALIK: That would be remarkable.

MR. PARKS: The licensee's approach for oxidation was to calculate oxidation on a fresh rod and then add their estimate of the pre-transient oxidation on top of that. So what they have is a conservative estimate of the oxidation because it's already oxidized. It's not going to oxidize as much during the transient.

MEMBER ABDEL-KHALIK: So the numbers there include the pre-transient oxidation or not?

MR. PARKS: They do.

MEMBER ABDEL-KHALIK: They do.

MR. PARKS: This is M5 cladding. It doesn't oxidize very much in our experience, results that we've seen.

MEMBER ARMIJO: I thought the analysis was for Zirc4 cladding. At least I read somewhere in the application that they used Zirc4 cladding.

MR. PARKS: I was mistaken. I apologize.

MEMBER ARMIJO: Okay. But you know, does anybody believe those numbers, 3.8793? Is it really necessary? Why not round it off at 4 percent? Anyway, go on.

MS. GALL: That's all I had for large break. Moving onto the small break --

CHAIR BANERJEE: Just for the record, there will be no -- you didn't do any confirmatory calculations, right?

MS. GALL: Correct.

CHAIR BANERJEE: The staff.

CONSULTANT WALLIS: And the main -- well, just to say what you did. Do you remember if the -- was for the largest break? Maybe we'll get to that in the --

MS. GALL: I'd have to go --

CONSULTANT WALLIS: -- proprietary session.

MS. GALL: Yes.

CONSULTANT WALLIS: Okay.

CHAIR BANERJEE: There are a couple of questions, Jennifer, about that we can address later.

MS. GALL: Yes.

CHAIR BANERJEE: Okay.

MS. GALL: So small break. Again, there were some -- we issued some RAIs. The staff was concerned that the break spectrum, the initial break spectrum had missed the cases or the break sizes right before and right after SI injection. So the licensee provided a re-analysis that tightened up the break spectrum to make sure that we covered all of the appropriate break sizes.

CHAIR BANERJEE: And did you find something unexpected by that?

MS. GALL: I don't think it was unexpected.

CHAIR BANERJEE: So it was still around

the break size that they had shown.

MS. GALL: Correct.

CONSULTANT WALLIS: Is there a kind of sudden jump when you get SI or don't? This is a continuous curve with break size, or is there a change in mechanism?

MR. PARKS: The staff's review approach for the small break is to look for a cutoff where the break size limits the accumulator's ability to inject and that's typically where we see a turn in the break spectrum.

CONSULTANT WALLIS: So there is a change in mechanism.

MR. PARKS: Yes. And so the reason that we asked for this more refined break spectrum is sort of put more definition to where that --

CONSULTANT WALLIS: Because you don't have a continuous curve.

MR. PARKS: I've plotted for PCT as a function of break size for other plants like this, but I don't think that we did it particularly for St. Lucie. It generally winds up being pretty smooth. In some cases it's not always smooth, especially when Appendix K modeling is being used, but in these analyses it tends to be.

CHAIR BANERJEE: So it goes through a peak, right? For a certain break size, the PCT. Now, that's more or less where -- do you get -- with the EPU reflux condensation, what fraction of the heat for this break size is removed by the steam generators? Is it a lot?

MR. PARKS: I don't expect it to be significant. These -- I'd have to look at the heatup numbers and see how long the cladding is heating up before it turns over.

CHAIR BANERJEE: So, if you are -- well, we'll take this under closed session, but the effect of the EPU would be that -- could be that you have a more extended period of reflux. But let's go to that later.

MEMBER ABDEL-KHALIK: Normally you have one charging pump operating.

MR. DUNN: I'm sorry to interrupt, but yes.

MEMBER ABDEL-KHALIK: When you get an SI signal it automatically starts the other two?

MR. DUNN: We need to -- That is correct. I have misspoken because I'm not used to the charging pumps all being activated.

MEMBER ABDEL-KHALIK: Right. So how small a hole does it have to be to match 150 gallon per minute charging pump flow? That must be a tiny hole.

MR. DUNN: Yes, it would probably be on the order of a three-quarter inch line break, or maybe a 1 inch. I haven't done that -- this is Bert Dunn.

MR. MIRANDA: Well, we saw in the curve that I presented for the inadvertent opening of a PORV that the three charging pumps are making up the flow through one PORV. Pressurizer level is increasing.

CHAIR BANERJEE: What was going out through the PORV?

MR. MIRANDA: Steam.

CHAIR BANERJEE: Right. In this case likely to be water.

MR. MIRANDA: That's right. Yes. Sorry.

CHAIR BANERJEE: But going back to the -- do you get any refluxing, any period of refluxing during the small break?

MR. DUNN: It would depend on the break size.

CHAIR BANERJEE: Let's say that your 3 and a half to 4 inch breaks.

MR. DUNN: I would expect it for that break. I need to go back and actually get the --

CHAIR BANERJEE: Can you get us that

answer?

MR. DUNN: I can do that.

CHAIR BANERJEE: Okay.

MS. GALL: Then to the loop-seal clearing. The re-analysis in addition to the more refined break spectrum provided the loop-seal clearing biasing. And that'll be discussed more in the closed session. And then additionally the licensee provided the SIT line break. And we found that the SIT line break did not provide limiting results with respect to the re-analysis of the --

CONSULTANT WALLIS: You have some points of small break LOCA with a peak. You have some points of large break LOCA with a peak. Then you have something in between which is significantly lower than both of them. Is that it, or there's a possibility of a peak between the SIT line break and the large break LOCA? Or between the SIT line break and the small break LOCA. Because there seems to be a --

MR. PARKS: Dr. Wallis?

CONSULTANT WALLIS: -- range that's not covered there somewhere.

MR. PARKS: Based on the information that we reviewed, and we're pulling a figure now to show that we -- we looked at PCT in the large break as a function of the break size.

CONSULTANT WALLIS: Yes.

MR. PARKS: And found that the largest breaks tended to be the highest in PCT there were.

CONSULTANT WALLIS: Okay, that's useful. So it's going down. Does it come down and fit the SIT line break --

MR. PARKS: I have to stop talking because I think the answer might be proprietary.

CONSULTANT WALLIS: Well, we'll get to that?

MR. PARKS: We'll get to it.

CONSULTANT WALLIS: Okay.

MR. PARKS: But we saw trending to show that as the break size came down the PCT was reduced.

CONSULTANT WALLIS: And then somehow it turns around and goes up for the small break.

MR. PARKS: Right.

CONSULTANT WALLIS: But you don't care about the minimum, you only care about the maximum. So I guess it's --

MR. PARKS: I wouldn't say that we don't care about the minimum. It's that we saw a trending down on both sides.

CONSULTANT WALLIS: It has to turn around somehow to get up to the small break. Maybe we'll get into that later, shall we? Just to understand why it does these things would be useful.

MS. GALL: And so there will be more discussion on small break and large break as we move forward. Next slide.

And in the analysis package or the additional analysis that the licensee provided there's a statement that led me to believe that this was -- the additional analysis was in addition to the original analysis that they had submitted. But I think that is not the case. Right?

CHAIR BANERJEE: Can you clarify that again?

MS. GALL: Yes.

MR. DUNN: Could you repeat?

MS. GALL: So, in -- they submitted an original small break LOCA analysis and then submitted this supplemental analysis that included the refined break spectrum and the loop-seal biasing and the SIT line break.

I believe it was the licensee's intent to replace the original analysis with the new analysis, but there's a statement in the letter saying that the original licensing report was limiting in comparison to the revised analysis.

CONSULTANT WALLIS: Sounds a bit odd because the revised analysis was conservative and also sought the biggest spectrum of breaks. So it's unusual for the original analysis to be higher, isn't it? You'd think introducing conservatism would drive it the other way.

MR. KABADI: Yes, this is Jay Kabadi from FPL. On the submittal I think as staff pointed out, there's a statement in there --

MR. MIRANDA: Could you speak up a little please?

MR. KABADI: Yes. The submittal which we made in May of 2011, that analysis was to replace the original analysis. And because this analysis has all the changes that staff requested about what was found to be acceptable. So the intent was the analysis submitted in May 2011 was to replace the original analysis. And as the staff pointed out, there is a statement in the submittal which may be a little unclear, and we can put that, and we need to clarify that.

MS. GALL: So there will be a resolution to this issue before the full ACRS meeting.

MEMBER ABDEL-KHALIK: Can you summarize

the modeling differences between the results in the first column and the results in the second column? What are the modeling differences?

MR. KABADI: And that is one of the -- this is Jay Kabadi from FPL. And that's one of the item to talk in the closed session.

MEMBER ABDEL-KHALIK: Okay.

MR. KABADI: What are the model changes done.

MEMBER ABDEL-KHALIK: This closed session is getting longer and longer.

MR. KABADI: I think during the -- yes. Initially my presentation mentioned that modeling changes done will be discussed in the closed sessions.

MEMBER ARMIJO: I just had a simple question. Was the EPU analysis, the original one, done with the realistic large break LOCA model or some other model?

CHAIR BANERJEE: This is a small break.

MS. GALL: This is small break.

MEMBER ARMIJO: The small break, was it done with the realistic or not?

MS. GALL: No, the small break is Appendix.

MEMBER ARMIJO: Okay.

CHAIR BANERJEE: But the EPU analysis showing his question still -- I'm confused between the EPU analysis and the additional analysis.

MEMBER SCHULTZ: That's what we have to clarify in the closed session.

CHAIR BANERJEE: Yes. Okay.

CONSULTANT WALLIS: So the EPU analysis is the original analysis?

MS. GALL: Yes, that was the original submitted with the original EPU application.

CONSULTANT WALLIS: And then when they put in more conservatism it went down.

MS. GALL: Yes.

MR. PARKS: We say it's conservative because generally when we request that they make these assumptions we see a significant increase in the PCT. And the point that Jen was making was that we thought we were looking at the additional analysis as a supplement to the EPU analysis. So our decisionmaking was based on the fact that they produced an original PCT of 2,072 and then they did some additional confirmatory studies to show that 2,072 was limiting.

In discussing our information with the licensee it very recently came to our awareness that that was not their intent. And Jen read you the statement in the submittal that made us think that. So we need to work through that with the licensee and we'll report back at full committee I think what the result is.

MEMBER SKILLMAN: So, should we see the additional analysis as the replacement analysis of record? Is that what you're really communicating here?

MR. PARKS: That is what FPL proposes.

MEMBER SKILLMAN: I see. Thank you.

CHAIR BANERJEE: But the staff has not agreed to that yet.

MEMBER SCHULTZ: But it would be useful for us to discuss that in closed session. To understand it better so we don't see it all at the full committee meeting.

CHAIR BANERJEE: With regard to the -- 72 or the 1807, they were for the same break size roughly?

MS. GALL: Roughly? Yes. Within a couple inches.

CHAIR BANERJEE: A couple of inches?

(Laughter)

MS. GALL: The number is proprietary.

CHAIR BANERJEE: Okay. All right. Let's

--

MEMBER REMPE: This is the last slide before closed session, right?

MEMBER SCHULTZ: It is.

CHAIR BANERJEE: So we are going on asking questions which we could do later. So, go ahead, Jennifer. Finish up.

MS. GALL: Both the original analysis as well as the supplemental analysis produced results that meet the 50.46 requirements.

CHAIR BANERJEE: Okay. So, I think is there anything else that we want to say in open session?

MR. ORF: Just one thing. We went back and verified all the CE, the prior CE power uprates. And there were about eight or more. There were eight. And they were all less than the current St. Lucie EPU.

CHAIR BANERJEE: But they were EPUs or they were just fraction or something else?

MR. ORF: The highest one was around 9 percent so they were probably --

CHAIR BANERJEE: In total?

MR. ORF: In total.

CHAIR BANERJEE: In total.

MR. ORF: Right. So those probably would

have been --

CHAIR BANERJEE: Below this.

MR. ORF: Probably would have been stretched.

MR. BOWMAN: Tracy, this is Eric Boone from Westinghouse. The last two recent ones that are CE was ANO2 in 2002 and that was approximately 7.5 percent. And that was an EPU with no MUR. And Waterford 3 was 2003 and that was 8 percent EPU with the 1.6 percent.

CHAIR BANERJEE: Okay, 2002 and 2003. So that's before my time. It was Graham's time. Were you involved in that?

CONSULTANT WALLIS: Sorry, I'm reading ahead.

CHAIR BANERJEE: Were you involved in these two Waterford 3 and what was the other one? ANO.

MR. BOWMAN: ANO2, sir.

CONSULTANT WALLIS: Probably. You'd have to look at the record.

CHAIR BANERJEE: But they were much smaller than this one in any case.

MR. BOWMAN: For actual wattage size Waterford at 9.6 total was at 275 megawatts thermal and ANO2 was just over 200 megawatts thermal.

CHAIR BANERJEE: Thank you.

MR. ORF: We should be ready for the end.

CHAIR BANERJEE: Okay. So you know what? Let's take a 5-minute break and come back at 5 to 2 and then we'll go into closed session. At that time will somebody please ensure that everything is set up. And we'll go off the record now for 5 minutes.

(Whereupon, the foregoing matter went off the record at 1:48 p.m. and resumed at 4:44 p.m.)

CHAIR BANERJEE: We are going back into open session right now, and we will have the staff tell us about the source terms and radiological consequences analysis.

MR. PARILLO: Good afternoon. My name is John Parillo. I'm in the Accident Dose Branch, in the Division of Risk Assessment in NRR, and I'm going to talk to you this afternoon about the review of the source terms and radiological dose and consequences analyses.

The first portion of the review that we conducted has to do with the source terms, the reactor coolant source terms, regarding the design of the clean-up systems in the plant for the radwaste. And the licensee was able to -- is not going to make any changes to the existing in-plant systems.

(Disruptions from teleconference system.)

CHAIR BANERJEE: Is that okay now?

MR. WANG: I don't know if Tom's still on the line.

CHAIR BANERJEE: Tom, are you still on?

(No response.)

CHAIR BANERJEE: Tom, are you back on?

(No response.)

CHAIR BANERJEE: This is the most complicated system I've ever seen. Tom? Well, I think we should go ahead, and we'll get him back.

MR. PARILLO: In this case, the licensee was able to just use scaling factors to show that they would be able to continue to meet the applicable regulatory requirements in Part XX and Appendix I, and the general design criteria 60.

So I didn't have a whole lot of issues with this portion of the review. There was a more substantial effort involved in reviewing the design basis dose consequence analyses. Just to give you a brief history, St. Lucie 1 had come in with a full-scope alternative source term back in November of 2008, but that was done at a power level of 2754 megawatt-thermal, which was the 2700 megawatt license power with a two percent uncertainty.

So for the EPU, the licensee submitted revised AST evaluations, done at a power level of a 3033 megawatt-thermal, which is basically 3020 plus a 0.3 percent, because they incorporated the measurement uncertainty recapture as part of the EPU. So that's why the percentage over the license power is smaller.

And so in order to facilitate our review, we usually ask these questions about, for each radiological dose analysis, to provide all of the input assumptions and parameters, key values, that are in your current licensing basis, and then provide all of the -- for each analysis, for each parameter -- show what that value is. And in this case, it would be for the EPU. And then, where any differences exist, to explain the bases for those differences.

So the licensee probably was reading RAIs, and they provided that table without us asking, which was very beneficial. That way, we can focus our attention on the variables that actually have changed. And in this case, most of them actually stayed the same, but there were some changes.

Obviously, the nuclide inventory changed, but there are also some changes in sump water temperature and flashing fractions, things of that nature. There were some changes in containment spray flow rates, and they actually took some -- added some conservatism in the control room ventilation flow rates that they used for their accident analyses.

And the atmospheric dispersion factors, or the chi over q values, also changed, because the licensee updated those values based on more recent meteorological data. So that was a brief synopsis of some of the changes. There wasn't any earth-shattering change, or anything that challenged any of our assumptions in the reg guide or anything like that.

And also, as part of the EPU amendment request, St. Lucie also included a re-analysis of their waste gas tank rupture accident, which is actually a Chapter XI consideration, but we took a look at that analysis as well. So basically, in short, all of the design-basis accidents -- when I say design-basis accident, I'm really referring to the Chapter XV-type analyses, that are done to meet the dose criteria that's set forth in 50.67, and they meet all of those criteria.

And I'd also like to say -- I mean, we don't grade licensees in terms of the margins that they provide to the limits, but I should -- I think it's worth noting that the off-site doses at St. Lucie 1 are very low, which I like to see, personally. Control room is always a challenge for most all licensees, but their off-site doses are well below the acceptable limits.

In terms of the waste gas decay tank rupture evaluation, the licensee also took a very conservative posture, in that they evaluated that accident based on the more stringent criteria of 100 millirem TEDE off-site, even though they have controls for explosion as well as seismic design, so they actually could have used a limit 25 times higher. But they chose to use the 100 millirem, which is the most restrictive limit, to set a new proposed tech spec for the xenon-135 dose equivalent that's allowed to be stored in the tank.

So there were no issues with that, in terms of they did a conservative analysis.

MEMBER SCHULTZ: John, one question regarding the dose analysis for Chapter XV. The most limiting analysis to the acceptance criteria was the large break LOCA to the control room dose?

MR. PARILLO: Yes.

MEMBER SCHULTZ: And my question was related to the unfiltered in-leakage --

MR. PARILLO: Right.

MEMBER SCHULTZ: -- data going to the control room. And I was just curious as to, the value that they used was provided, but I didn't know how that compared to their measured value.

MR. PARILLO: Yes, and I actually scrambled around for that one. I don't actually have their test value, but what I can say is that they have a comfortable margin, insofar as they're pretty much -- and if the plant people are here, they can correct me if I'm misstating this. But I think what the licensee's approach to the control room infiltration, as regards the to the dose analysis, is that they give themselves a very comfortable margin over what they predict they will get in an actual test.

And so that way, it looks as though they have a very tight margin -- I think it's like 4.8 rem TEDE to the limit of 5. But they have given themselves some operational flexibility there, so that when they come in for this very expensive tracer gas testing, that they won't have to worry. Because, you know, typically -- for instance, the numbers that they have is currently 460 CFM of unfiltered in-leakage. This is an assumed value.

That's pretty high. I mean, we've seen

values as low as 10. So we're not overly concerned that they should be able to meet that limit. And actually, it should be comfortable for them to show compliance with that limit when they do their control room testing.

MR. HALE: This is Steve Hale, Florida Power and Light. That test data from 2011, as he said, our acceptance criteria is 460 CFM. In the pressurization mode, the unfiltered in-leakage was 18, and in the recirc mode it was 58. So that gives you -- that's test data from 2011.

MEMBER SCHULTZ: Thank you.

MR. PARILLO: Okay. So that pretty much wraps it up. Do you have any questions?

CHAIR BANERJEE: Are there any questions?

(No response.)

CHAIR BANERJEE: Thank you very much. Do we have any public comments?

MR. HOFFMAN: Dr. Banerjee?

CHAIR BANERJEE: Yes?

MR. HOFFMAN: Just one quick point. This is Jack Hoffman, Florida Power and Light. Just as a follow-up, there was a question asked earlier about some of the historical test results from St. Lucie on our safety valves.

CHAIR BANERJEE: Yes.

MR. HOFFMAN: And we've been able to obtain the test results for the last ten years on our main steam safeties. We're looking at the pressurizer safeties. Those are done off-site, and it's a little bit harder to get those test results.

But for the main steam safety valves, again, current conditions, we have two banks of safety valves. The first bank is at 1,000 psia, the second is at 1,040 psia. Both of those banks have a tech spec acceptance criteria of plus one percent, minus three percent; plus 10 pounds, minus 30 pounds, roughly.

And we did have two failures of main steam safety valves in the year 2002. Both were on the low side. They just barely failed. They failed out of that 30 pound range by .37 and .17 psi. And since that timeframe, in the last ten years, we've tested 36 valves, main steam safety valves, and zero have failed. And that's to today's standards of +1, -3. We're expanding that for some operational flexibility as part of the EPU to +3, -3 for the low bank, and +2, -3 for the high bank.

MEMBER ABDEL-KHALIK: And you're looking for data on the primary side?

MR. HOFFMAN: Yes. We don't have that today, but we're looking for it. We tested the main steam safety valves on-site, so those results are readily available in test procedures. The safety valves, pressurizer safeties, we have to send off-site for as-found testing, and we have to dig up those vendor reports.

MEMBER ABDEL-KHALIK: All right. Thank you.

MR. HOFFMAN: You're welcome.

CHAIR BANERJEE: Thanks very much. Thank you. And now -- Bill, do you have to run away or something?

MEMBER SHACK: I'm just getting ready. I have a few minutes.

CHAIR BANERJEE: Okay. So I'm going to -- has there been any member of the public who wants to make a comment, do we know?

(No response.)

CHAIR BANERJEE: No one. Okay. So what I'll do is just go around the table, as usual, take comments, and then I'll also get Weidong to summarize what information we have been asking for. Or would you like to do that first, to start with?

MR. WANG: I can try, to see if it's

complete.

CHAIR BANERJEE: So the other members -- people can add to it. Or remove it, if they've resolved some matter.

MR. WANG: I'll go backwards from the latest, flipping back. I think you, Dr. Banerjee, asked about U bend holdup during the flux condensation?

CHAIR BANERJEE: Well, flooding.

MR. WANG: Flooding, okay.

CHAIR BANERJEE: Well, actually, just to amplify on that, so AREVA knows, there are people in AREVA who are very involved, also, with the EPR, who will know this issue extremely well. So if you wanted to get their help, they will -- but of course, I asked the staff, also, for their comment on this, which is Len Ward, I think?

MR. WANG: Yes, Len Ward is supposed to take this section.

CHAIR BANERJEE: He would understand the issue pretty well.

MR. WANG: So this is one. And the next one is the loop seal clearing document.

CHAIR BANERJEE: Yes, any information,

MR. WANG: Any information for this loop

seal clearing.

CHAIR BANERJEE: On the methodology.

MR. WANG: Methodology, okay. And so Professor Tom Downer, he is asking about the power shape, and with the xenon and the verifications, and I think AREVA knows to take this action.

CONSULTANT DOWNER: Also, just any very succinct and concise explanation of how that's used in the calculations.

MR. WANG: Okay. Next question is, Joy asked about this FRAPCON calculation, basically the latest SER. The staff needed to provide to me that latest SER.

MEMBER REMPE: And apparently it's a reference to the document. So if we could have a copy of the audit report, too. I don't know how sensitive it is. If there were other changes, too, in the SER, from what we had, that we reviewed, that would be helpful to know.

MR. ORF: Yes, it's mostly just editorial.

MEMBER REMPE: Okay.

MR. WANG: And for this -- I believe Said here asked about for the thermal conductivity degradation, he's looking for the correlation with the linear heat rate.

MEMBER ABDEL-KHALIK: Segregation of the data.

MR. WANG: Further data, yes. And this is also the applicant needed to provide the --

CHAIR BANERJEE: Well, if I understand it, it was that the applicant stated -- at least AREVA stated that they'd looked at this issue, and you wanted to see just what they had got.

MEMBER ABDEL-KHALIK: Right.

MR. WANG: Let's see if I have any more.

MEMBER ABDEL-KHALIK: Well, the last thing is what we just said, that they will provide data for the primary safety set point group.

MR. WANG: Yes, that's also one. I believe this -- okay, I think this is for the staff, action, that you provided like an EPU analyses, and also additional analyses, and you still need to confirm with me, with us, about if this additional analysis is a replacement, or it's just an addition to the original analyses.

CHAIR BANERJEE: This is for the small break.

MR. WANG: For the small break.

CHAIR BANERJEE: Just a clarification, right?

MR. WANG: Yes.

CHAIR BANERJEE: That's all.

MEMBER SCHULTZ: Well, if it's a replacement, we may need more information than what was provided.

CHAIR BANERJEE: Yes. Well, the staff has not resolved it themselves, I have the impression. Right?

MR. WANG: And another action, I don't know if, Dick, you maybe can add to it, is about PORV stuck, or just open, that question. PORV. I believe you talked about it's basically a difference between stuck open or normal open, I would assume.

MEMBER SKILLMAN: I don't believe any action is necessary on that.

MR. WANG: Okay. Then I'll cross this.

MEMBER SKILLMAN: But I do have one that you haven't mentioned, and that is the thermal hydraulic transient on reverse flow, and dropping a reactor cooling pump. I would like to know that that cycle has been accounted for.

MR. HOFFMAN: Just for clarification, that is a thermal cycle?

MEMBER SKILLMAN: That is a thermal cycle.

MR. HOFFMAN: Okay.

MEMBER SKILLMAN: It's a reverse flow on a --

MR. HOFFMAN: Okay. But structurally --

MEMBER SKILLMAN: It's a structural issue. It's the nozzles, and the delta T versus time.

MR. HOFFMAN: Understand.

MEMBER SKILLMAN: I feel like there's one thing we probably should have asked but didn't, and I don't want to lose the chance. When we talked with the Turkey Point crew, we were very interested in flooding. This is an ocean site. We should touch that, at least for several minutes, at least to make sure that we've not let that topic stray from this meeting.

CHAIR BANERJEE: Okay. Does the staff have any comments on this, the propensity of this site to exhibit any problems with flooding?

MR. ORF: I don't think we have anybody here to speak to that.

MEMBER SKILLMAN: I just checked the safety evaluation, and the safety evaluation is silent on that issue.

MR. ULSES: What we'll have to do is take an action to get back to you on that. We don't have the staff here right now to address that, and I suspect, given the time of day, they're probably not here actually in reality, either. So we'll take an action and get back to you on that.

CHAIR BANERJEE: All right. So let's note that.

MR. WANG: I believe this is on my list. I think there may be other action items now being addressed, and I'll now go over the table to see if there's anything I left.

CHAIR BANERJEE: Okay. So why don't I just start with Mario, and then we'll just go around the table?

CONSULTANT BONACA: Generally, I found the application and the SER good, in general. I went through a review of a specific system, which was the auxiliary feeder system, because there is so much history behind that, from the construction of the plant to the TMI action items, and so on and so forth. And that was kind of disappointing, because I was searching for understanding the level of redundancy in that system, if in fact the increased demand had affected that.

I asked that question yesterday, this morning, here, and I got an immediate answer. So it was easy. But I probably covered 60 or 70 pages in the application and the SER dealing with that issue, and never coming to that particular conclusion. So it's just a comment. That was frustrating, in part. And even the PRA portion of the discussion on the aux feed, the peer review had commented on this issue, the fact that there was no clear understanding of this issue, and the criteria used to determine redundancies.

I don't know what to do with that, but I just wanted to mention that because I spent time on it.

I thought that they had an adequate analysis of transients, non-LOCA accidents and transients. And what I did not like was the way they presented the results, the issue of 2750 psi. And the reason is that they are clearly using a bounding effect on parameters, to the point where these are already surrogate calculations, and now it's even more surrogate.

For the reader, it's difficult to understand the specific transient, and the way it runs. I mean, if you have to understand it from the FSAR, from the SER, from the application, I mean, you will not be able to do that, necessarily.

On the LOCA issue, the fuel thermal

conductivity degradation, it's clearly the issue to deal with, and I think there is sufficient recommendation now for the licensee to come back and try to clarify that. I think that they may have a way out, but that has to be seen.

And I'll try to summarize this in a letter to you.

CHAIR BANERJEE: Yes. So, just to let everybody know, before we go further, we are on a very tight schedule, because we have agreed to write a letter in the May meeting, the full committee meeting. So Tom, Mario, Graham, everybody, actually, we need your feedback as soon as possible. Preferably this weekend, if we can have it. And if we can't, as soon as possible after, because there isn't much time.

Anyway, so we will now move on to you, Graham.

CONSULTANT WALLIS: Well, I read the SER. It's very long. It covers a great deal of -- a great many topic. And it reads well. It seems like they're meeting these requirements. What I missed in the whole thing was, what's the effect of EPU? I mean, they go through all this thing, and they meet this requirement, they meet this requirement, they meet this requirement. Well, how does it differ from what was before?

At this meeting, I found I got confused about some matters, such as the way that the TCD was handled, and the way the loop seal was handled, and some aspects of --

CHAIR BANERJEE: Speak up.

CONSULTANT WALLIS: Some aspects of the small break LOCA. So I'm going to go away, and see if I can figure it out. And I hope I can do it by the time that you need something, but there are some things that are a little puzzling, puzzle me a bit.

CHAIR BANERJEE: Okay. Steve?

MEMBER SCHULTZ: I appreciate the detailed discussions that were presented by both the applicant and the staff today. I have no further comments or questions, and look forward to the additional information that Weidong is going to bring forward, again hopefully very soon.

MEMBER SKILLMAN: I compliment the staff and the Florida Power team for a thorough presentation. The questions that I've already presented are the ones that I will be focusing on when I put my comments together, and I thank the team for a job well done.

MR. GIL: This is Rudy Gil, FPL. Gordon,

for the comment on the flooding, I guess you'll clarify the type of input you're looking for there? Is that going over the design basis that we have, or --

MEMBER SKILLMAN: Well, I'll be curious what the NRC staff presents. Rudy, you were here for the Turkey Point discussions, and we zeroed in on that. Not necessarily with Fukushima as a backdrop, but just general --

CHAIR BANERJEE: Excuse me. He can't hear you.

MEMBER SKILLMAN: Oh, I'm sorry.

CHAIR BANERJEE: You'll have to talk into the --

MEMBER SKILLMAN: We addressed this very thoroughly on the Turkey Point application from a professional accountability perspective, given the backdrop of Fukushima. And so I'm interested in what the staff will communicate in terms of their review regarding site flooding. That was the topic that we were so focused on in the Turkey Point EPU effort.

CHAIR BANERJEE: How far is the site above whatever water level there is?

MEMBER SKILLMAN: The Atlantic Ocean. That's the question.

CHAIR BANERJEE: How far above is it?

MR. ORF: Flood level is 19 feet above -- I mean, below low level.

MEMBER SKILLMAN: Could I just observe that, perhaps at Turkey Point, the 50.54(f) letters hadn't been issued yet. Now, I think, the issue you're asking about is going to be addressed under 50.54(f). It doesn't seem we need to take it up here, would be my judgment.

MR. GIL: There are evaluations that will be done under 50.54(f).

MEMBER SKILLMAN: Of course. We know that.

CHAIR BANERJEE: So thank you, Harold. We're happy with that.

MEMBER SKILLMAN: Thank you.

CHAIR BANERJEE: Go for it.

MEMBER RAY: Two things. One, I'd like to say on the record that the very low pump seal leak rates -- and my colleagues know I'm interested in that topic -- are a result of the replacement of the original seals, and so they're less dependent upon component cooling water to survive a blackout, which I was glad to be informed about. And since that occurred off the record, I wanted to make the comment here.

The only other thing I'll say is, I think that I wouldn't characterize a 10 percent increase beyond experience for the rho v squared as a slightly higher value, but I believe that information was presented here and in response to our questions which adequately establishes confidence that their planned operation, as far as the secondary side of the steam generators is concerned, will be safely managed and there won't be any expectations of excessive wear. And it'll be detected if there is any such thing occurring, well in advance of when it would be problematic.

And that's all I have to say. I may suggest to you, Sanjoy, some acknowledgement of that for the letter. It's up to you whether you want to --

CHAIR BANERJEE: Yes, I think both you and I can work together on that, maybe, Harold. On the calibration issue.

MEMBER RAY: That's fine.

CHAIR BANERJEE: All right. Sam?

MEMBER ARMIJO: I'm satisfied that the treatment of thermal conductivity degradation on the fuel has been resolved. It's messy, starting with RODEX2, but it's been addressed with the augmentation fixes. And so I don't have a problem with any of that.

We didn't talk about it much, and Bill's already mentioned from the materials, it's a really clean application. So I think it's in good shape. Thank you.

CHAIR BANERJEE: Thanks.

MEMBER RYAN: Thank you, sir. I believe that the source term and radiological consequence analyses were well done, and basically well-characterized by the staff, so that there's no need to repeat that discussion. But well done on that score. Thank you.

CHAIR BANERJEE: Any issues with the fuel after the EPU went into the pools?

MEMBER RYAN: I don't think so. You mean the spent fuel pool?

CHAIR BANERJEE: Yes.

MEMBER ABDEL-KHALIK: I have no additional comments.

CHAIR BANERJEE: Thank you.

MEMBER SHACK: I'll get you some paragraphs on materials this weekend.

CHAIR BANERJEE: So I'm going to talk about that.

MEMBER REMPE: No additional comments, but I would like, if possible, to have the updated information and the staff audit calcs as soon as possible.

CHAIR BANERJEE: Yes.

MEMBER REMPE: And thanks for the presentations from both organizations.

CHAIR BANERJEE: So I think -- the subcommittee, of course, thanks both the applicant, AREVA, and the staff for very good presentations and almost getting it all done in time. It's amazing. This has seldom happened for as far as I remember. So congratulations, and thank you.

Because we are so constrained in terms of getting the letter out, I'm going to ask you to send me whatever feedback you have as quickly as possible, and to structure it a little bit. So of course, all of you, I appreciate your remarks on the safety analysis, and I'll integrate it and put it together. It'll have to cover a whole range of accidents, a lot of things, and if you look at previous letters we've written, for example on Point Beach and so on, you can get an idea of the coverage that we have.

MEMBER RYAN: Sanjoy, to that end, it would be helpful if we could ask, however we need to, to expedite the transcript.

CHAIR BANERJEE: Right, that would also be very useful. I wonder if that is possible, or not, on the transcripts, how quickly it can be done. Normally, of course, we have a month or a month and a half --

MR. WANG: Normally a week and a half for transcripts.

CHAIR BANERJEE: A week and a half.

MR. WANG: I'll talk to Charles, because I think we can --

THE COURT REPORTER: Of course, that's possible. There are some billing implications for that, but you can talk to my office about that.

CHAIR BANERJEE: Mike, your point is well taken. So the second point -- well, the areas that we are interested in, to structure it a little bit, are safety analysis, materials, which we will take care of, flow-induced vibrations, I just made a sort of note of how we want to structure things. So Harold and I will handle that.

Somebody who feels really interested in this should write something about the risk evaluations, and I'm wondering who could do that. Because normally it would be somebody like Dennis or

John or somebody, but nobody is there. And I was wondering if Steve and Dick, you could do this together? I'm looking to you for the electrical systems.

MEMBER SKILLMAN: I've got electrical.

CHAIR BANERJEE: Okay.

MEMBER SKILLMAN: I'll go with that.

CHAIR BANERJEE: So Steve, maybe you can take a look -- I don't think there are any major issues, but take a look.

One of the things that we normally talk about, and that we didn't talk about, is the power ascension testing and transients. It's all in the SE, so we should look at it. I didn't see anything particularly to be dealt with, but we'll have to make some comment, and we'll do that. And I'll take care of that. That's not a problem.

And I think that more or less covers things. Of course, the bulk of everything will be in the safety analysis part. So, have I missed something?

MEMBER REMPE: Would the safety analysis part talk about what's been done on thermal conductivity degradation?

CHAIR BANERJEE: Yes. Yes, it'll be

there. We might break out a subsection or something to cover it.

MEMBER SKILLMAN: Do we have the most recent safety analysis? That's what we need, Weidong.

MR. WANG: Right. And also, once I've got it, because it's proprietary, I always have trouble to communicate it to you. Because it looks like so many documents I need to pass to members, but this time, you know, we don't have much time. And normally I put everything on a CD, because I cannot email.

MEMBER RAY: FedEx works just fine. We don't -- don't worry about it.

MEMBER SKILLMAN: Can you make a CD and FedEx it to us?

MR. WANG: Yes, I can do that.

MEMBER RAY: FedEx works just fine.

MR. WANG: But you may expect that, because one week I get this one, next week I get that one.

CHAIR BANERJEE: Yes, this email system is hard to access, and all the proprietary stuff.

MEMBER RAY: CDs work really well. And we can say that without being contradicted.

MR. WANG: Okay.

CHAIR BANERJEE: So we'll look forward to seeing you all at the full committee meeting. Thank you very much for your time.

MEMBER RAY: Bang the hammer.

CHAIR BANERJEE: And of course, we have an hour and a half with the staff.

(Whereupon, the above-entitled meeting was concluded at 5:20 p.m.)

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UNITED STATES NUCLEAR REGULATORY COMMISSION

Protecting People and the Environment

ACRS Subcommittee on Power Uprates

NRC Staff Review
St. Lucie, Unit 1
Extended Power Uprate

April 26, 2012

Opening Remarks

Allen G. Howe
Deputy Division Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Opening Remarks

- NRC staff effort
  - ❖ Pre-application review and public meetings
  - ❖ Requests for additional information
  - ❖ Audits
- Challenging review areas included:
  - ❖ Inadvertent Opening of a PORV analysis
  - ❖ Feedwater Line Break analysis
  - ❖ Inadvertent ECCS/CVCS actuation
  - ❖ CEA Withdrawal at Power

Introduction

Tracy J. Orf

Project Manager

Division of Operating Reactor Licensing

Office of Nuclear Reactor Regulation

Introduction

- Background
  - ❖ St. Lucie 1 EPU Application – November 22, 2010
  - ❖ 2700 to 3020 MWt, 12 % increase (320 MWt)
    - Includes a 10 % power uprate and a 1.7 % MUR
    - 18 % increase above original licensed thermal power
- EPU Review Schedule
  - ❖ Followed RS-001
  - ❖ No Linked licensing actions
  - ❖ Supplemental responses to NRC staff RAIs and Audits
  - ❖ EPU Implementation

Topics for Subcommittee

- EPU Overview
- Materials – Steam Generators
- Fuel and Core
- Safety Analyses
- Dose Analysis

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St. Lucie Unit 1 EPU Accident Analyses

Samuel Miranda and Jennifer Gall
Reactor Systems Branch
Office of Nuclear Reactor Regulation

Review of Accident Analyses

- Feedwater Line break
- Mass Addition Events
  - ❖Inadvertent ECCS actuation
  - ❖CVCS Malfunction
  - ❖Inadvertent opening of a PORV
- Loss of Coolant

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Feedwater Line Break (FWLB)

- FPL defined FWLB as a cooldown event in the licensing basis
- FPL did not analyze FWLB, since the Main Steam Line Break analysis produces a more severe cooldown
- The staff did not accept this approach

FWLB

- FWLB is treated as a heatup event in RG 1.70 and SRP Section 15.2.8
- The staff requested an analysis of FWLB as a heatup event
- FWLB analysis results were audited on January 30-31
- Acceptable FWLB analysis results: RCS subcooling is maintained

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Inadvertent Actuation of ECCS

- Inadvertent Actuation of ECCS can fill the pressurizer, and pass water through the PORVs.
- A small break LOCA is created if a PORV sticks open.
- AOOs are not permitted to develop into events of a more serious class.

Inadvertent Actuation of ECCS

- Inadvertent ECCS actuation is not in St. Lucie’s licensing basis
- Shutoff head of ECCS (SI pumps) is lower than RCS nominal pressure
- Analysis was not provided in the EPU application

Inadvertent Actuation of ECCS

- Charging pumps (PDPs) have been added to the ECCS since the FSAR
- Charging pumps can fill the pressurizer and cause water relief through the PORVs

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Non-Escalation Criterion

- “By itself, a Condition II incident cannot generate a more serious incident of the Condition III or IV type without other incidents occurring independently.”
- NRC reminded licensees that this criterion is in the plant licensing bases, and therefore must be met (RIS 2005-29).

Inadvertent Actuation of ECCS

- Conservative composite of Inadvertent Actuation of ECCS and CVCS Malfunction was analyzed
- It took almost 11 minutes, after the high pressurizer level alarm, to fill the pressurizer
- This is deemed to be sufficient for manual remedy

Inadvertent Opening of a PORV

- RG 1.70 classifies this AOO as a decrease in RCS inventory event
- RCS depressurization reduces thermal margin, which leads to trip
- RCS continues to depressurize and reaches low pressure SI setpoint
- Lower RCS pressure boosts ECCS delivery rate. Pressurizer can fill.

Inadvertent Opening of a PORV

- Operator can close the PORV very quickly after it opens (< 10 sec)
- With no operator action:
  - ❖SI signal is generated in < 2 min
  - ❖Pressurizer fills in < 7.5 min
  - ❖Charging pumps can cause PORVs to open and relieve water
  - ❖A PORV can stick open (SBLOCA)

Inadvertent Opening of a PORV

St. Lucie Unit 1 EPU – Information to Support NRC Review of RCS Depressurization With Pressurizer Overfill

ANP-3067
Revision 1
Page 23

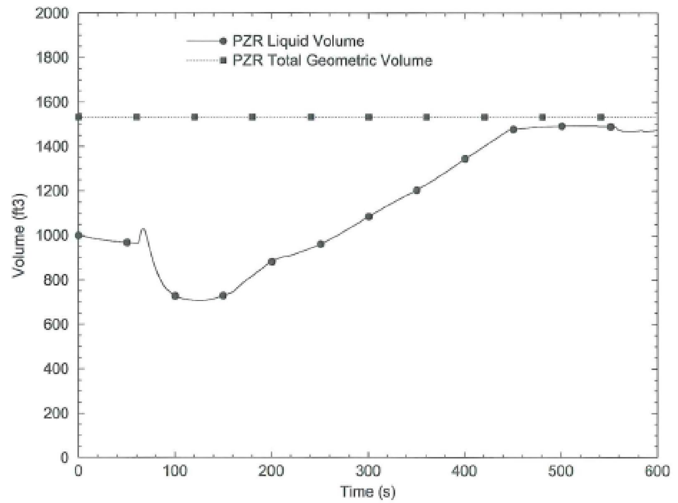

Figure 8 RCS Depressurization / Pressurizer Overfill – Pressurizer Liquid Volume

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Audit (January 2012)

- Feedwater line break,
- Inadvertent opening of a power operated relief valve,
- Chemical and volume control system malfunction,
- Loss of electrical load, and
- Realistic large break loss of coolant accident.

Review of LOCA

- Realistic Large Break
  - ❖ Licensee implemented EMF-2103, "Realistic Large Break LOCA Methodology for Pressurized Water Reactors."
  - ❖ Plant-specific analysis includes modeling assumptions that are more conservative than the NRC-approved model
- Small Break
  - ❖ Licensee implemented EMF-2328, "PWR Small Break LOCA Evaluation Model, S-RELAP5 Based."
  - ❖ Licensee included the following assumptions:
    - Loop seal clearing more reflective of experimental data
    - Additional break spectrum detail

Realistic Large Break LOCA

- Plant-specific modeling assumptions:
  - ❖Power level and decay heat not ranged
    - Bounding model used
  - ❖Rod quench conditions
    - Void fraction < .95 AND
    - Tclad< min temp for film boiling heat transfer
  - ❖TCD
    - Polynomial expansion applied

Realistic Large Break LOCA

- Conclusions
  - EM used was more conservative than the NRC-approved model
  - Results demonstrate compliance with 10 CFR 50.46 requirements

Parameters	Fresh UO2 Fuel	Once Burned UO2 Fuel	10 CFR 50.46 Limits
Peak Clad Temperature	1667 ^{o}F	1639 ^{o}F	2200 ^{o}F
Maximum Local Oxidation	2.5268	3.8793	17.0 %
Maximum Total Core-Wide Oxidation (All Fuel)	0.0209	NA	1.0 %

Small Break LOCA

- Break Spectrum
  - ❖Re-analysis with more refined break spectrum
- Loop Seal Clearing
  - ❖Re-analysis with biases to allow only the broken loop to clear
- SIT Line Break
  - ❖Licensee provided analysis

Small Break LOCA

- Conclusions
  - ❖Original SBLOCA analysis was limiting

Parameters	EPU Analysis	Additional Analysis	10 CFR 50.46 Limits
Peak Clad Temperature	2072 ^{o}F	1807 ^{o}F	2200 ^{o}F
Maximum Local Oxidation	11.06%	<4%	17.0%
Maximum Total Core-Wide Oxidation (All Fuel)	0.156%	<1%	1.0%

St. Lucie Unit 1
Extended Power Uprate (EPU)
ACRS Subcommittee

April 26, 2012

Agenda

- **EPU Overview**
  - Introduction………………………………………. Rich Anderson
  - Plant Changes…………………………………… Jack Hoffman
- **Materials**
  - Steam Generators ……………………........……… Rudy Gil
- **Analyses**
  - Fuel and Core ………………….......………………. Jay Kabadi
  - Safety Analysis ……………………………………. Jay Kabadi
  - TCD / LBLOCA (Proprietary) …………………… Jay Kabadi
- **Acronyms**

St. Lucie Unit 1

- Located on Hutchinson Island, southeast of Fort Pierce, Florida
- Pressurized Water Reactor (PWR)
- Combustion Engineering Nuclear Steam Supply System (NSSS)
- Westinghouse Turbine Generator
- Architect Engineer – Ebasco
- Fuel supplier - AREVA
- Unit output 950 MWe gross

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St. Lucie

- **Original operating license issued in 1976**
- **Steam Generators (SGs) replaced in 1998**
- **Renewed operating licenses issued in 2003**
- **Installation of a new single-failure proof crane to support spent fuel dry storage operations in 2003**
- **Reactor Vessel Head and Pressurizer were replaced in 2005**
- **Replaced 2 of 4 Reactor Coolant Pump motors in 2010 and 2012**
  - The remaining motor replacements planned for 2013 and 2015

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St. Lucie

- **Licensed Core Power**
  - Original Licensed Core Power — 2560 MWt
  - Current Licensed Core Power — 2700 MWt
    - -- Stretch Uprate 105.5% (1981)
  - EPU Core Power — 3020 MWt
    - -- Implement 2012

FPL is requesting approval for a 12% power level increase for St. Lucie Unit 1

- **12% increase in licensed core power level (3020 MWt)**
  - 10% Power Uprate
  - 1.7% Measurement Uncertainty Recapture
  - (2700 x 1.10) x 1.017 ~ 3020 MWt
- **Classic NPSH requirements for ECCS pumps are met without credit for containment overpressure**
- **Grid stability studies have been completed and approved for the EPU full power output**
- **Final modifications to support EPU operation are being implemented in 2012**

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EPU License Amendment Request (LAR) was prepared utilizing the guidance of *RS-001, Review Standard for Extended Power Uprates*

- **Addressed lessons learned from previous PWR EPU reviews**
- **Evaluations consistent with the St. Lucie Unit 1 Current Licensing Basis (CLB) per RS-001**
- **License Renewal evaluated in each License Report section consistent with RS-001 requirements**
- **Measurement Uncertainty Recapture evaluated the proposed Leading Edge Flow Meter (LEFM) system using the Staff's criteria contained in *RIS 2002-03, Guidance on the Content of Measurement Uncertainty Recapture Uprate Applications***

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Engineering studies were performed to evaluate systems, structures and components to determine the ability to operate at EPU conditions

- **Analyzed the effects of increases in Reactor Coolant System temperature and power, and increases in steam flow, feedwater flow and electrical output**
- **Heat balances developed for current power level and EPU NSSS power level of 3050 MWt (core + pump heat)**
- **Changes in major parameters addressed for Balance of Plant (BOP) systems and components**
- **Hydraulic analyses performed on feedwater, condensate and heater drain systems**
- **Plant normal, off-normal and transient conditions evaluated**
- **Operating experience was evaluated and applied**

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Analyses were performed to evaluate the changes in design parameters

Parameter	Original	Current	EPU	EPU Change
Core Power (MWt)	2560	2700	3020	+320
RCS Pressure (psia)	2250	2250	2250	0
Taverage (°F)	565.6	574.2	578.5	+4.3
Vessel Inlet (°F)	542.0	549.0	551.0	+2.0
Vessel Outlet (°F)	589.2	599.4	606.0	+6.6
Delta T (°F)	47.2	50.4	55.0	+4.6
Thermal Design Flow (gpm/loop)	185,000	182,500	187,500	+5,000
Core Bypass (%)	3.7	3.9	4.2	+0.3
Steam Pressure (psia)	848	896	890	-6
Moisture Carryover (maximum, %)	0.20	0.10	0.10	0
Steam Mass Flow (10^6 lb/hr)	11.18	11.80	13.42	+1.62

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Modifications will be made in support of safety

- Increase Safety Injection Tank design pressure
- Increase Hot Leg Injection flow
- Add online Containment mini-purge capability
- Upgrade Main Steam Isolation Valves (MSIVs)
- Nuclear Steam Supply System (NSSS) setpoints
- Add neutron absorption material to Spent Fuel Pool storage racks
- Install Leading Edge Flow Measurement (LEFM) System
- Environmental Qualification (EQ) radiation shielding changes for electrical equipment
- Safety related piping support modifications
- Raise Reactor Protection System (RPS) Steam Generator low-level trip setpoint (plant risk profile enhancement)

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Modifications will be made in support of power generation at the EPU power level

- **Steam Path**
  - Replace High and Low Pressure Turbine steam paths
  - Replace main turbine Electro Hydraulic Control (EHC) System
  - Replace Moisture Separator Reheaters (MSRs) and upgrade level controls
  - Increase Steam Bypass Control System capacity and upgrade control system
  - Upgrade steam and power conversion system instrumentation
  - Modify Main Steam piping supports
- **Condensate and Feedwater**
  - Replace Main Feedwater Pumps
  - Upgrade Main Feedwater Regulating Valves and controls
  - Replace #5 High Pressure Feedwater Heaters
  - Upgrade Main Condenser
  - Modify Main Feedwater piping supports

- Continued on next page -

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Modifications will be made in support of power generation at the EPU power level (continued)

- **Heater Drains**
  - Replace Heater Drain pumps
  - Upgrade Heater Drain valves
- **Auxiliary Support Systems**
  - Replace Turbine Cooling Water heat exchangers
- **Other Balance of Plant items**
  - Balance of Plant (BOP) setpoints
  - Condensate piping supports

- Continued on next page -

FPL

Modifications will be made in support of power generation at the EPU power level (continued)

- **Electrical Modifications**
  - Generator upgrades including
    - -- Stator rewind
    - -- Rotor replacement
    - -- Replace bushings and current transformers
    - -- Replace hydrogen coolers
    - -- Increase hydrogen pressure
    - -- Replace exciter air coolers
  - Install Power System Stabilizer
  - Upgrade Iso-Phase Bus Duct cooling system
  - Increase margin on AC electrical buses
  - Upgrade Main Transformer cooling systems
  - Switchyard modifications

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Analyses demonstrated acceptable Steam Generator tube wear at EPU conditions

Steam Generator Analysis Results

Parameter	Acceptance Criteria	Results
Maximum fluid-elastic instability velocity ratio	<1.0	0.742
Maximum vortex shedding resonance amplitude	<0.015 in.	0.005 in.
Accumulated tube wear over the 40 year design life	<40% nominal tube wall thickness	12.9% U-Bend 16.3% Tube Bundle Entrance *

* Decreases for EPU conditions

Steam Generator parameters at EPU conditions are comparable to the current industry operating experience

B&W – Series 67 Replacement
Steam Generator Comparison

Plant	Pitch Velocity (Downcomer Entrance) [ft/sec]	Volumetric Flow Rate U-Bend [ft^3/sec]	Axial Velocity (V) (U-Bend Entrance) [ft/sec]	Mixture Density (ρ) [lbm/ft^3]	ρV^2 (U-Bend) [$lbm/ft\text{-}sec^2$]
St. Lucie 1 (EPU Conditions: 3034 MWt NSSS)	11.38	722	11.97	9.899	1418
St. Lucie 1 (Current conditions: 2714 MWt NSSS)	11.43	657	10.89	10.939	1297
Millstone Unit 2 (Current conditions: 2714 MWt NSSS)	11.65	670	11.08	10.917	1341
Calvert Cliffs 1 & 2 (Current conditions: 2717 MWt NSSS)	11.81	653	10.85	11.325	1334

Operating experience shows the expected tube wear is acceptable for uprate condition

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Based on excellent Steam Generator operating performance no tube wear issues are expected at EPU conditions

- **Although ρv^2 slightly higher than current experience base, the predicted tube wear will only increase slightly from 12.7 to 12.9 (% Wall Thickness) well within the acceptance criteria of <40%**
- **Many years of operating experience with no indication of tube vibration problems with Steam Generators comparable to St. Lucie Unit 1**
- **Periodic Steam Generator tube inspections at St. Lucie Unit 1 have provided no indication of unusual tube wear**
  - The Steam Generators have performed very well with only 14 tubes plugged in SG-1A and 1 tube in SG-1B
- **Although not anticipated by analysis, on-going Steam Generator tube inspections will provide early indication if problems were to occur**
  - Steam Generator inspections planned for first refueling outage after operation at EPU conditions

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Fuel design maintains margin to limits

Fuel Design

- **CE14 High Thermal Performance (HTP) fuel design implemented in previous cycles**
- **License Amendment Request (LAR) submittal addresses two guide tube designs**
  - Standard design currently in use at St. Lucie Unit 1
  - MONOBLOC™ design (incremental change relative to standard design)
- **Peak rod and assembly burnup will be maintained within current limits**

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Margins to key safety parameters are maintained

Core Design

- **Representative core designs were used for EPU analyses**
- **Core design limits are reduced to offset effect of EPU and maintain margins to fuel design limits**
  - Total integrated Radial Peaking Factor (F_r^T) COLR limit reduced from 1.70 to 1.65
  - Linear heat rate COLR limit reduced from 15.0 kW/ft to 14.7 kW/ft
- **Normal incore fuel management methods utilized to meet reduced limits with increased energy needs**
  - Feed enrichment & feed batch size
    - -- Maximum enrichment changed from 4.5 to 4.6 wt% U-235 planar average
  - Burnable absorber placement
  - Core loading pattern

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Margins to key safety parameters are maintained (continued)

Core Design Changes (continued)

- **Moderator Temperature Coefficient limits are unchanged**
- **Shutdown Margin requirement is unchanged for at-power operation**
  - Larger doppler power defect at EPU conditions, but Shutdown Margin (SDM) remains acceptable
- **Boron requirements met**
  - Boron delivery capability improved by changes to boron requirements for the Boric Acid Makeup Tank (BAMT), Refueling Water Tank (RWT) and Safety Injection Tanks (SITs)
  - Minimum refueling boron increased to 1900 ppm

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Approved methods used for safety analysis as supplemented by subsequent RAI responses

- **Codes and methodologies**
  - S-RELAP5: large & small break LOCA
  - S-RELAP5: Non-LOCA transients
  - XCOBRA-IIIC: DNB analysis of the nuclear fuel
- **Safety analyses include additional input parameters biasing beyond the requirements of approved methodology**

Safety analyses demonstrate acceptable results

- **Key changes beneficial to safety analysis**
  - Reduction of Peak Linear Heat Rate (PLHR) and Radial Peaking Factor (F_r^T)
  - Increase in minimum SIT pressure
  - Increase in minimum RCS flow rate
- **Conservative inputs/assumptions**
  - Conservative physics parameters
  - Bounding plant operating parameters include measurement uncertainties and operating bands
  - Conservative trip setpoints and delays
  - No credit for non-safety grade equipment to mitigate events
  - Input parameters biased in the conservative direction for limiting events; e.g.:
    - -- RCS pressure, temperature, flow (min vs. max)
    - -- Pressurizer level (nominal ± uncertainty)

Safety analyses include appropriate input changes

- Power measurement uncertainty at Rated Thermal Power (RTP) reduced from 2% to 0.3%
- Maximum steam generator tube plugging reduced from 15% to 10%
- Main Steam Safety Valve setpoint tolerance revised from +1%/-3% (Banks 1 and 2) to +3%/-3% (Bank 1) and +2%/-3% (Bank 2)
- Safety Injection Tanks (SIT) pressure range revised from 200-250 psig to 230-280 psig
- Minimum SIT and Refueling Water Tank (RWT) boron concentration requirement revised from 1720 ppm to 1900 ppm

Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria

Analysis Methodologies

Method	Pre- EPU	EPU
Non-LOCA System Transient Analysis	PTSPWR2, ANF-RELAP & S-RELAP5 Computer Codes	S-RELAP5 Computer Code
Thermal-Hydraulic Core Analyses	XCOBRA-IIIC	XCOBRA-IIIC
	HTP CHF correlation	HTP CHF correlation

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Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
Decrease in RCS Flow	Loss of Flow (AOO)	MDNBR ≥ 1.164	1.319
	Locked Rotor (PA)	Rods-in-DNB ≤ 19%	0%
RCS Overheating (Decrease in Secondary Heat Removal)	Loss of Load (AOO)	RCS Press. ≤ 2750 psia	2744 psia
		MSS Press. ≤ 1100 psia	1092 psia
	Loss of Load to one SG (AOO)	MDNBR ≥ 1.164	1.867
	Loss of Feedwater (AOO)	Liq. Vol. ≤ Pressurizer Vol.	~70% span
		RCS Subcooling ≥ 0°F	47°F
	FW Line Break (PA)	RCS Subcooling ≥ 0°F @ time when AFW heat removal matches core decay heat	9°F

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Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
RCS Overcooling (Increase in Secondary Heat Removal)	Increase in Steam Flow (AOO)	MDNBR ≥ 1.164	1.385
	Inadvertent Opening of SG Safety Valve (AOO)	MDNBR ≥ 1.164 (No loss of SDM)	SDM > 0 pcm
	HFP Pre-scram MSLB (PA)	Rods-in-DNB ≤ 1.2% (OC) & ≤ 21% (IC)	0.46%
		Fuel Melt ≤ 0.29% (OC) & ≤ 4.5% (IC)	0%
	HZP/HFP Post-scram MSLB (PA)	Rods-in-DNB ≤ 1.2% (OC) & ≤ 21% (IC)	0%
		Fuel Melt ≤ 0.29% (OC) & ≤ 4.5% (IC)	0.02%

Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
Reactivity Addition	CEA Withdrawal @ HZP (AOO)	MDNBR ≥ 1.164	6.087
		Fuel CL Temp. ≤ 4908°F	2036°F
	CEA Withdrawal @ Power (AOO)	MDNBR ≥ 1.164	1.239
		RCS Press. ≤ 2750 psia	2657 psia Bounded by LOEL
	CEA Drop (AOO)	MDNBR ≥ 1.164	1.566
		Peak LHR ≤ 22.279 kW/ft	20.75 kW/ft
	CEA Ejection (PA)	RCS Press. ≤ 3000 psia	2696 psia Bounded by LOEL
		Fuel Enthalpy ≤ 200 cal/g	166.4 cal/g
		Rods-in-DNB ≤ 9.5%	0%
		Fuel Melt ≤ 0.5%	0%

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Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
Reactivity Addition	Boron Dilution (AOO)	Time-to-Criticality ≥ 15 min. (Modes 1 – 5)	≥ 25.46 min.
		Time-to-Criticality ≥ 30 min. (Mode 6)	39.56 min.
RCS Mass Addition	Inadvertent ECCS/CVCS (AOO)	Liq. Vol. ≤ Pressurizer Vol.	~1423 ft^3 @ 10 min. after High Level Alarm
RCS Depressurization	Inadvertent Opening of a Pressurizer PORV (AOO)	MDNBR ≥ 1.164	1.350
		Liq. Vol. ≤ Pressurizer Vol.	~1399 ft^3 @ 7 min. after PORV opens

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Small Break LOCA safety margin is assured by key changes

Parameter	SBLOCA Pre-EPU Value	SBLOCA EPU Value
Licensed Core Power (MWt)	2700	3020
Power Measurement Uncertainty (%)	2.0	0.3
Analyzed Core Power Level (MWt)	2754.0	3029.2
Radial Peaking Factor (F_r^T)	1.75	1.65
Peak Linear Heat Rate (kW/ft)	15.0	14.7
Steam Generator Tube Plugging (%)	30	10
Minimum SIT Pressure (psig)	200	230

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Small break LOCA analysis demonstrates acceptable results

- Incorporates additional analysis from recent licensing experience
- Not impacted by thermal conductivity degradation

	Pre – EPU (Appendix K)	EPU (Appendix K)	Limit
Limiting Break Size	4.28-inch	3.65-inch	-
PCT (°F)	1765	1807	2200
Maximum Transient Local Oxidation (%)	2.5	3.47	17.0
Maximum Core-Wide Oxidation (%)	< 1.0	0.04	1.0

FPL.

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Acronyms

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Acronyms

AFW	Auxiliary Feedwater
AOO	Anticipated Operational Occurrences
BAMT	Boric Acid Makeup Tank
BOP	Balance of plant
CHF	Critical Heat Flux
CLB	Current Licensing Basis
CVCS	Chemical and Volume Control System
DNB	Departure From Nucleate Boiling
ECCS	Emergency Core Cooling System
EHC	Electro Hydraulic Control
EPU	Extended Power Uprate
F	Fahrenheit
FCM	Fuel Centerline Melt
F_r^T	Total Radial Peaking Factor
ft	Feet
GPM	Gallons per minute
HFP	Hot Full Power
HTP	High Thermal Performance
HZP	Hot Zero Power
IC	Inside Containment
Keff	K-effective
lb/hr	Pounds per hour
LEFM	Leading Edge Flow Meter
LHGR	Linear Heat Generation Rate
Liq	Liquid
LOCA	Loss of Coolant Accident
LOEL	Loss of Electrical Load
MDNBR	Minimum Departure From Nucleate Boiling Ratio
MSIV	Main Steam Isolation Valve
MSLB	Main Steam Line Break
MSR	Moisture Separator Reheater
MSS	Main Steam System
MWe	Megawatts electric
MWt	Megawatts thermal
NPSH	Net Positive Suction Head
NSSS	Nuclear Steam Supply System
OC	Outside Containment
OD	Outside Dimension
PA	Postulated Accident
PLHR	Peak Linear Heat Rate
PORV	Power Operated Relief Valve
PPM	Parts per Million
Pres	Pressure
PSIA	Pound per square inch - absolute
PWR	Pressurized Water Reactor
PZR	Pressurizer
RCS	Reactor Coolant System
RIS	Regulatory Issue Summary
RPS	Reactor Protection System
RTP	Rated Thermal Power
RWT	Refueling Water Tank
SIT	Safety Injection Tank
SDM	Shutdown Margin
Sec	Second
SG	Steam Generator
V	Velocity
Vol	Volume
ρ	Density

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Source Terms and Radiological Consequences Analyses

John Parillo
Accident Dose Branch
Division of Risk Assessment
Office of Nuclear Reactor Regulation

Source Terms for Radwaste Systems Analysis

- Reviewed using Review Standard for Extended Power Uprates
- 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

- On November 26, 2008, the licensee was issued an amendment to adopt a full-scope Alternate Source Term (AST) per 10 CFR 50.67 based on a power level of 2754 MWt (2700 + 2%).
- The EPU submittal included revised AST evaluations based on a power level of 3033 MWt (~3020 + 0.3%).

DBA Radiological Consequences Analyses

- The licensee provided a table detailing for each input/assumption, the current licensing basis value, the revised EPU value and the bases for any indicated changes.
- The Saint Lucie Unit 1 EPU amendment request also included a reanalysis of an accidental waste gas release based on EPU conditions.

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Protecting People and the Environment

DBA Radiological Consequences Analyses

- All DBAs evaluated for the AST meet 10 CFR 50.67 and SRP 15.0.1 dose acceptance criteria both offsite and in the control room.
- The waste gas decay tank rupture evaluation meets Part 20 criterion for members of the public as well as General Design Criterion 19 for the Control Room.

DBA Radiological Consequences Analyses

- Licensee has adequately accounted for the effects of the proposed EPU.
- The NRC staff finds the proposed EPU acceptable with respect to the radiological consequences of DBAs.