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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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FRIDAY

JUNE 22, 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., Joy Rempe, Chair, presiding.

SUBCOMMITTEE MEMBERS PRESENT:

JOY REMPE, Chair

SANJOY BANERJEE

CHARLES H. BROWN

STEPHEN P. SCHULTZ

GORDON R. SKILLMAN

NRC STAFF PRESENT:

WEIDONG WANG, Designated Federal Official

TRACY ORF

MICHELE EVANS

DOUG BROADDUS

SAM MIRANDA

BENJAMIN PARKS

TIM MOSSMAN

NORBERT CARTE

ALSO PRESENT:

JOE JENSEN

JACK HOFFMAN

STEVE HALE

TODD HORTON

JAY KABADI

DAVE BROWN

RUDY GIL

JESSICA TATARCZUK

DOUG ATKINS

KIM JONES

JEFF BROWN (via telephone)

TERRY JONES

A G E N D A

(Open)

Page

P R O C E E D I N G S

8:30 a.m.

Opening Remarks

CHAIR REMPE: Good morning. This meeting will now come to order. This is a meeting of the Power Uprates Subcommittee, a standing subcommittee of the Advisory Committee on Reactor Safeguards. I'm Joy Rempe, the Chairman of the Subcommittee.

ACRS members in attendance include Dick Skillman, Stephen Schultz, Sanjoy Banerjee and Charlie Brown. Our ACRS consultants, Graham Wallis and Mario Bonaca are also present, and Weidong Wang of the ACRS staff is the Designated Federal Official for this meeting.

In this meeting, the Subcommittee will review the St. Lucie Unit 2 license amendment request for an extended power uprate. We'll hear presentations from the NRC and the representatives from the licensee, Florida Power and Light Company.

We've 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, the presentations will be closed, in order to discuss information that's

proprietary to the licensee and its contractors, pursuant to 5 U.S.C. 552(b)(C)(4).

Attendance at this portion of the meeting that deals with such information will be limited to the NRC staff and its consultants, Florida Power and 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.

Today, 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'll now proceed with the meeting, and I'd like to start by calling upon Mr. Trace Orf from the staff.

MR. ORF: I'd like to introduce Michelle Evans.

Introduction

MS. EVANS: Good morning, thank you. My name is Michelle Evans. I'm the Director of the Division of Operating Reactor Licensing in the Office of Nuclear Reactor Regulation. I appreciate the opportunity to brief the ACRS Power Uprate Subcommittee this morning.

In the interest of time, my opening remarks will be brief. At this meeting, the NRC staff will present to you the results of our safety and technical review of the licensee's application. Our review was supported by pre-application meetings and other meetings, audits and several conference calls with the licensee.

Through these numerous interactions, technical concerns were identified, discussed and resolved in a timely manner. Some of the more challenging review areas that you will hear about today include safety analyses of inadvertent opening

of a PORV, and CFCS malfunctions.

As was discussed during recent ACRS meeting, the staff became aware of an emerging issue regarding the fuel thermal conductivity under-prediction that may affect the best estimate upper tolerance limit of the peak climbing temperature for PWR, large-break loss of cooling accidents.

The licensee will provide a presentation on how this issue impacted the ECCS evaluation for the St. Lucie for the St. Lucie EPU, and its resolution for this issue. The staff will be available to address any questions.

A draft safety evaluation was provided to the ACRS on May 31st. We'd like to thank the ACRS staff who assisted us with the preparations for this meeting, especially Weidong Wang. At this point, I'd like to turn over our discussion to our NRR project manager, Trace Orf, who will introduce the discussions. Thank you.

MR. ORF: Good morning. As Michelle said, my name is Trace Orf. I'm the NRR project manager for St. Lucie. Today, you will hear presentations from Florida Power and Light and the NRC staff, and the objective of those presentations 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 the 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 2 EPU.

On February 25th, 2011, the licensee submitted its license amendment request for the St. Lucie Unit 2 EPU. The proposed amendment will increase the unit's licensed core power level from 2,700 megawatts thermal to 3,020 megawatts thermal.

This represents a net increase in license core thermal power of approximately 12 percent, including a ten 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 RS001, which is NRC's review plan for EPUs. As you know, it provides the safety evaluation template, as well as matrices that cover the multiple technical areas that the staff is to review.

While there were no linked licensing actions associated with the EPU application, the spent fuel pool and new fuel storage evaluations and analyses were separated out for scheduling purposes. There were numerous supplements to the application, responding to multiple staff RAIs.

Overall, there were approximately 80-supplemental responses that supported our draft safety evaluation. Also, the staff completed several audits to complete its review and resolve open items.

CHAIR REMPE: What's the estimated date on completing the fuel storage pool evaluation?

MR. ORF: It will be completed concurrent with the EPU.

CHAIR REMPE: Which date is?

MR. ORF: Oh, I'm sorry. Let's see. The full committee is scheduled for --

CHAIR REMPE: July?

MR. ORF: --for July. So it generally takes about 60 days afterwards to complete the EPU amendment. So that would be around the end of August.

CHAIR REMPE: Okay.

MEMBER SKILLMAN: Trace, you mentioned that there were about 80 supplemental items. Is that a large number or a small number for an EPU?

MR. ORF: That's approximately -- there's generally between 40 and 100.

MEMBER SKILLMAN: Thank you, thank you.

MR. ORF: You're welcome. Okay. Part of the large number was in order to expedite the review of the review, instead of sending out RAI sets in batches. As the questions arose during the review, each item was sent separately to the licensee, so the licensee could begin a response.

MEMBER SKILLMAN: Thank you.

MR. ORF: You're welcome. The current slide lists the topics for today's discussion. Florida Power and Light will begin by providing an overview of the EPU, and the NRC staff will then each make the presentation. FP&L and the NRC staff will each make their presentations on fuel and core and safety analyses. Lastly, Florida Power and Light will present information on steam generators.

Finally, at the conclusion of the meeting, as needed, we can discuss any additional questions in preparation for a full committee meeting. Also to note, the majority of the afternoon sessions will be closed. 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, and unless there are any further questions, I would like to turn over the presentation to Mr. Joe Jensen and FP&L. Mr. Joe Jensen is the Site Vice President for the St. Lucie nuclear power plant.

(Pause.)

EPU Overview

MR. JENSEN: Okay. Now that we've overcome that technical difficulty, I'll get started. Good morning. My name is Joe Jensen. I am the Site Vice President for the St. Lucie nuclear power plant. I want to thank the Subcommittee for the opportunity to speak on behalf of Florida Power and Light regarding the extended power uprate of St. Lucie Unit 2.

Here today to share information about the St. Lucie Unit 2 EPU or Jack Hoffman, our licensee manager for the St. Lucie EPU; Rudy Gil, who will be presenting towards the end of the day on the steam generators, who is the manager of our major components inspection group; Jay Kabadi, manager of Nuclear Fuels Group for St. Lucie; and Chris Wasik, licensing manager.

This is a significant undertaking for our

company, that will not only license, that will not only increase the output of the plant, but will also provide equipment upgrades to improve plant reliability and availability, without cutting into any of our margins, and improving overall performance of the plant, and Jack Hoffman will discuss that later.

A little bit about the plant. St. Lucie is located on Hutchinson Island, southeast of Fort Pierce, Florida, and is the primary electrical generation source for St. Lucie County. It's a Combustion Engineering plant with Westinghouse turbine generators. The original architect engineer was Ebasco, and the nuclear fuel supplier is Westinghouse.

The gross electrical output of the plant is 907 megawatts electric prior to the EPU modifications. However, note that since we replaced the LP turbines during the last refueling outage, we've gained another 31 megawatts electric, and our current gross electrical output is 938 megawatts electric.

With regard to some of our key milestones and major equipment replacements for the St. Lucie Unit 2 plant, the original operating license was issued in 1983. In 2003, a renewed operating license was issued for Unit 2, extending operation of the

plant until 2043.

Also in 2003, a new single failure-proof crane was installed to support our spent fuel storage operations, and steam generators were replaced in 2007. Additionally in 2007, the reactor vessel head was replaced to address Alloy 600 issues.

Finally, we replaced two of the four reactor coolant pumps in 2007, excuse me, reactor coolant pump motors in 2007 and 2011, and we intend to replace the other two in 2012 and 2014.

The original licensed power for Unit 2 was 2,560 megawatts thermal. An approximately six percent stretch power uprate was implemented in 1985, increasing the licensed core power to 2,700 megawatts. This was accomplished with relatively few hardware modifications to the plant.

The extended power uprate we're discussing today will increase the licensed core power of Unit 2 to 3,020 megawatts thermal, which represents an additional 100 megawatts of clean nuclear energy. This completes what I intended to cover as far as my introduction, and what I'd like to do now is turn some time over to Jack Hoffman, who will summarize the changes to the plant. Thank you.

MR. HOFFMAN: Thank you, Joe. Good

morning. My name is Jack Hoffman and I'm the licensing manager for the St. Lucie Unit 2 extended power uprate project. As stated earlier, FPL has submitted a license amendment request for an approximate 12 percent license core power increase for St. Lucie Unit 2.

This proposed power increase is consistent with that recently approved for St. Lucie Unit 1, and consists of a ten 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 license core power level to 3,020 megawatts thermal. Also for the EPU, for St. Lucie Unit 2, the emergency core cooling pump net positive suction head or NPSH was analyzed using classic analytical methods. Sufficient pump NPSH margin exists at EPU conditions without taking credit for containment overpressure.

A grid stability impact study 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 at the proposed EPU power level, and results of the grid simulations indicate acceptable grid performance for the most extreme event.

Finally, the remaining modifications to support operation of St. Lucie Unit 2 at the uprated power level will be implemented in 2012.

CHAIR REMPE: Have you started? Go ahead. Okay. Have you started the implementation? Are you putting modifications into the plant now or where are you, because --

MR. HOFFMAN: Currently, the plant's operating. Our next outage will be in August of this year. But the last St. Lucie Unit 2 outage we took the advantage of that outage to implement a number of required EPU modifications, such as the electrical generator modifications and the lower pressure turbines.

That was the required inspection outage for those components. So it just made sense to -- we had to perform the inspections. We had to take that hardware apart. So it just made sense to make those major modifications at that point in time. So we have been operating almost the whole cycle with the main generator upgrades, and also, as Joe mentioned, with the low pressure turbine changeout.

So for St. Lucie Unit 2, it's a two outage implementation, with the remainder being implemented in the fall of this year.

CHAIR REMPE: Okay, thank you.

MEMBER SKILLMAN: An NPSH question, Jack.

MR. HOFFMAN: Yes.

MEMBER SKILLMAN: I read in the RAI "The methodology for adjusting the NPSH required values is based on an article in *Pumps and Systems* magazine, August 2009, by Terry Henshaw, P.E., Do pumps require less NPSH on Hydrocarbons Stepping NPSH or to different speeds."

Can you explain why your team used a magazine article for NPSH requirement, versus Hydraulics Standards Institute, guidelines or other ASME-type guidance?

MR. HOFFMAN: Sure. Let me explain what we did with NPSH. When we did -- first, the base NPSH analyses were the analyses we performed as a requirement for generic Safety Issue 191, GSI 191, the sump issue.

For EPU, we took those analyses and we actually added additional conservatism to determine what our actual limiting margin was for our two most limiting pumps, which are containment spray and high

pressure safety injection.

What we did is for the NPSH required, which is typically off of a vendor curve, performance curve that's done in the shop, we wanted to adjust that curve for NPSH required, again conservatively, based on what our technical specification allowable diesel generator frequency tolerance is. We're allowed a plus or minute one percent tolerance on diesel frequency, which affects pump speed, which will affect pump performance.

So we conservatively adjusted the NPSH required, which typically comes off a manufacturer's curve. The actual NPSH analyses, where you determine NPSH available, were done using classical ASME or Hydraulic Institute standard NPSH analyses.

We just simply adjusted the required NPSH an additional amount, to see what that margin would be, and the only available source we could find within the industry on how to adjust an NPSH-required curve was in that article. And at the end of the day, with all the conservatism that we had factored into the analyses, we still have approximately 28 percent margin, NPSH margin for our high pressure safety injection pumps, and about 36 percent margin for our containment spray pump.

MEMBER SKILLMAN: Okay, and that would be at the run-out conditions?

MR. HOFFMAN: That is correct. Actually, extreme run-out conditions. Again, diesel over frequency, IST margin instrument uncertainty, and we used those extreme flows to calculate the actual head loss, which is factored into the NPSH available.

So we robbed on both ends. We minimized NPSH available; we adjusted NPSH required to minimize that margin, and at the end of the day, we still had in excess of 27 percent for our limiting pump.

MEMBER SKILLMAN: Thank you, Jack.

MR. HOFFMAN: Okay, next slide. The St. Lucie EPU license amendment request was developed using guidance contained within RS001. The amendment addressed lessons learned from previous pressurized water reactor EPU submittals, including Ginnae, Beaver Valley, Comanche Peak, Point Beach and Turkey Point.

In accordance with RS001, the St. Lucie EPU analyses and evaluations were performed consistent with the St. Lucie Unit 2 current licensing basis. Also, the impact of EPU on license renewal was evaluated in each licensing report section. These analyses and evaluations address system structures and components or SSCs, subject to new aging effects due

to changes in operating environment, SSCs that have been added or modified to support EPU operating conditions, and also the impact of EPU on license renewal time-limited aging analyses was also evaluated.

As mentioned previously, the proposed uprate includes the measurement uncertainty recapture. The MUR submittal follows the guidance of NRC Regulatory Issue Summary or RIS 2002-03, and the St. Lucie Unit 2 MUR methodology is identical to the uprates recently approved for Turkey Points Units 3 and 4, and St. Lucie Unit 1.

MEMBER BROWN: Before you go on, are you going to have any discussion on your architectural installation or how LEFM is installed, what it feeds, how it is to be used? I guess I have a few questions --

MR. HOFFMAN: Sure.

MEMBER BROWN: --relative to that. But let me make sure I understand its use first.

MR. HOFFMAN: Sure.

MEMBER BROWN: Obviously, you have to do a calorimetric at some point --

MR. HOFFMAN: That's correct.

MEMBER BROWN: --to get your reactor power

and your actual plant power, thermal power coordinated.

MR. HOFFMAN: Correct.

MEMBER BROWN: Is this system used to automatically correct the NIs on a continuous basis?

MR. HOFFMAN: No.

MEMBER BROWN: So how is it -- I mean from what I read, just to make sure I get this stated correctly here, I'm going to read it out of the LAR. It says "The LEFM checklist system communicates with the DCS, which is a distributed control system"?

MR. HOFFMAN: That is correct.

MEMBER BROWN: Via a digital communications interface. There's two CPUs involved with the system. The data is sent. It's limited to values actually used in the calorimetric calibrations, fine, the calculations rather. It goes on to say that the mass flow rate temperature is to be integrated into appropriate DCS calorimetric display screens.

I presume somewhere there's algorithms that work on all this stuff to get you the answers you want --

MR. HOFFMAN: Absolutely.

MEMBER BROWN: --processing in the DCS system, as opposed to the LEFM system; is that

correct?

MR. HOFFMAN: Right, right.

MEMBER BROWN: Okay, and then it said "hard wire alarms go to the main control enunciators," which it's installed in the main control room." It then goes on to say "the LEFM checklist system will also communicate with the PI system," which has no discussion, no definition and not even a definition of the acronym in the LAR. What is the PI system?

MR. HOFFMAN: We call that the "pie system," and it's simply a display of various parameters within the power plant. There's a number --

MEMBER BROWN: It's the main control room?

MR. HOFFMAN: It's in the main control room, and it's actually on engineering work stations, and it's just a useful tool for operators and engineers to pick out whatever parameter they want to see, and they can pick the time, time span, you know, whether it's a day, the last month. It's just a historian for data and a display for data.

MEMBER BROWN: All right, I got that. Then it says let's see, "will communicate via a digital communications interface with appropriate cybersecurity safeguards."

MR. HOFFMAN: That's correct.

MEMBER BROWN: Okay, and that's all that's stated relative to cybersecurity safeguards.

MR. HOFFMAN: Right, right.

MEMBER BROWN: These PI system communication links will provide the same high level data to the DCS, the DCS as well as LEFM performance and diagnostics, you know, for performance monitoring. I guess my question is okay, now it's in the DCS. Is it -- at some point, does the DCS communicate with the outside world via, because you talk about Ethernet connections throughout those discussions.

You never say where they go or who they talk to, or what the level of communication is, one way, bi-directional. Ethernet is typically bi-directional, and can be controlled from outside, by outside sources who hack in.

MR. HOFFMAN: Right, right.

MEMBER BROWN: So in the absence of diagrams and some architectural representation of where this information goes to, it gives the clear impression it just disappears out of the plant and gets siphoned off via some Ethernet connection to outside world, the Internet, corporate world, whatever.

There was no mention, relative to the cybersecurity, what type of reg guides or what interfaces govern, for instance, RG 5.71, which lays out a level of isolation for critical plant data, which this is. It also leaves open the question about whether somebody could get in and modify that data as it is being presented to the operators, if you've got an Ethernet connection coming into the DCS.

So I don't know how you're going to explain all that in this particular meeting, but I did want to make you aware that somewhere along the line, I would like to get a clear understanding of why nobody is ever going to be able to get in. RG 5.71 makes it fairly clear that if you're going to communicate outside the main plant, it should be a one way only communication link.

MR. HOFFMAN: That's correct, that's correct.

MEMBER BROWN: And Ethernet does not -- and ideally, as it's stated, although it's not required because it's a Reg Guide, ideally it should be what I would call -- it's not necessarily analog, but a digital surreal data link of some type that is only one way, for instance, LEDs and an optocoupler-type arrangement where it can go one way but it can't

come in the other way.

MR. HOFFMAN: Sure, sure.

MEMBER BROWN: So anyway, those are -- that's kind of the high level point, in order to try to understand why this system is not compromisable by outside forces, where even though it's not automatically updating, and I'll get to that question here in a minute. I'm kind of verbose at some points.

You can't, in other words, provide misleading information, which would lead the operators to take some action, which is not consistent with the actual power level in the plant.

MR. HOFFMAN: Right.

MR. HALE: This is Steve Hale, Florida Power and Light.

MEMBER BROWN: I was waiting for you to stand up.

MR. HALE: I just, I think the point we need to make clear is that, you know, these are existing systems in the plant.

MEMBER BROWN: I got that. I'm not living and dying by existing systems. Right now, we're going and jacking up the plant tower. We're, how you're using better instrumentation to utilize it, which I have no problem with. It still says now, and

fundamentally we're operating at higher power levels with the same design core, utilizing the information we have.

So it doesn't mean we should just grandfather everything without an understanding, without an understanding of how that is being taken care of. It's not encompassed in the LER in any place, and not addressed by the staff in the SER as well.

MR. HALE: But I think that, you know, in terms of cybersecurity, there's certain activities ongoing right now with regards to improving overall cybersecurity plant-wide. You know, the point I was just trying to make here is that, you know, we really didn't change the availability of data and the communication of data as a result of this, you know. It's really the interface with the plant computer system, and that's -- which exists today.

MEMBER BROWN: That's fine. I haven't had a chance to look at this stuff ever until these last few and cyber becoming a more interesting issue as we move forward, as we try to define how that function is going to be satisfied for all the plants, one way or another.

So no, I understand. I appreciate your

point. So don't, I'm not denigrating your point. Don't take it that way.

MR. HALE: All right, thank you.

MR. HOFFMAN: Yeah. Let me just add on to what Steve has said. Several years back, going from analog to digital technology, we implemented a distributed control system is what we call it or DCS in the control room, that provides the operator -- there's a number of different systems that communicate with the Distributed Control System in the control room, to provide operators with much better information, touch screens and what-not, and that is isolated from the outside world.

That is a system that is specific and does not communicate outside the control room. The way we implemented the Leading Edge Flow Meter modification is we simply, using the DCS as the what I'll call the brains to do the calorimetric calculation, the outputs of the LEFM provides the inputs into the DCS to do the calorimetric calculation.

The calorimetric information is displayed in the control room. The calculated calorimetric information is displayed in the control room, and that's not communicated with the outside. That information, correct me if I'm wrong Todd, is used by

the operators to validate power, NI power.

MR. HORTON: Yes. Good morning. Todd Horton, Florida Power and Light. I oversee the operating crews. The PI system in which we were talking about earlier, that is not a system that the operating crews utilize to operate the power plant. They utilize the Distributed Control System and our normal, in this case power, would be our normal wide range nuclear instrumentation and safety channel, linear range safety nuclear instrumentation.

The PI system is more of a tool for the Engineering Group and management outside the control system, to look at those same-type indication is that the operators would use, and it gives us the ability to trend that information.

MEMBER BROWN: Okay. Let me, let me continue from page 2.4 dash .8, where it says "Each LEFM CPU will communicate with a dedicated DCN front-end Ethernet interface module. The active CPU data source for the DCS calorimetric calculations will be automatically swapped by the DCS when necessary, based on quality status flags originating from the LEFM, and from the Ethernet interface module," whatever that means, wherever that's coming from, whoever has access to it.

I'm not interested in saying DCS is not okay. I'm not interested in saying it can't be used. That's not -- my point is that Ethernet interface, where does it go and who has access to it?

MR. HOFFMAN: That Ethernet connection is strictly between the LEFM hardware in the turbine building, and the CPUs in the control room, all within the power block. There's no external communication. That's simply the internal Ethernet connection between field hardware and --

MEMBER BROWN: Does the DCS connect out to the outside world via any communication at all?

MR. HOFFMAN: I'm not aware of that. We can validate that.

MEMBER BROWN: If you could do that, that would be a nice --

MR. HOFFMAN: That's part of -- we can take that action. Steve will just validate. What does communicate with the outside is what Todd said, it's the PI system, which is --

MEMBER BROWN: How does the DCS and other stuff communicate with the PI system?

MR. HOFFMAN: That I don't know, but --

MEMBER BROWN: Well, that would be the other point of vulnerability, because that's a

potential external --

MR. HOFFMAN: Yeah, and as Steve said, that's existing, and you know, we've had the PI system and DCS --

(Simultaneous speaking.)

MEMBER BROWN: Existing or not, I would like to know whether that's truly a one-way --

MR. HOFFMAN: I understand.

MEMBER BROWN: Or whether it has access, people can actually access it and tell the PI system to do things or provide information to them. Because if you're connecting with that via the Ethernet system as well, then you're just daisy-chaining the dual bi-directional communications all the way into the plant.

MR. HOFFMAN: Well, I know that's not the case with LEFM.

MEMBER BROWN: So if that could be shown.

MR. HOFFMAN: Sure.

MEMBER BROWN: Or something provided that illustrates that, figuratively, functionally or what have you, that would be appreciated.

MR. HOFFMAN: Yeah. That scheme again is all part of the bigger cybersecurity issue that's germane to everything. You know, LEFM is a small piece that's been added on to that platform. I

understand the question. We'll have that information for you later today.

MEMBER BROWN: Okay. Thank you very much.

MR. HOFFMAN: Sure.

MEMBER BROWN: Thank you, Joy. I didn't see any other place to bring this up, and I did see all the rest of the slides.

MR. HOFFMAN: No, this is the right place.

(Simultaneous speaking.)

MR. HOFFMAN: You picked the right spot.

MEMBER BROWN: Okay, thank you.

MR. HOFFMAN: Yeah, okay. Next slide, Chris. Okay. Moving on. Comprehensive engineering analyses were --

MEMBER BROWN: I take that back. I did have one other comment.

MR. HOFFMAN: Sure.

MEMBER BROWN: Because I didn't see this addressed either, and maybe the staff will address this later. But utilizing this system allows you to pick up an extra 1.7 percent, based on your earlier slides and based on the LARs.

MR. HOFFMAN: That's correct.

MEMBER BROWN: You then go through a discussion, and the staff did in their SER also, of

when it's out of service.

MR. HOFFMAN: That's correct.

MEMBER BROWN: However, there's 48 hours allowed. So it can go out of service, and you can continue to operate for some period of time, even though now you don't have this ability to "normalize" the old system, the old alternate venturi DP cell temperature system that feeds the calorimetric calibrations. You can't normalize it anymore.

And then in addition to that, you go through a chain, which says well, if we just got a little piece of this is out, then we can do this and a little piece of that then it's this, and a little piece of that.

I guess I have a hard -- maybe the staff is going to have to convince me later, but I have a hard time figuring out that if my main calibration of saying I'm okay for this higher power is out of service for two days, that it's okay to just, from my background, at least in the Naval nuclear program, if I had this go out, we would have been down to the lower power in a heartbeat, without saying well gee, we know it was okay when it broke and everything was all right.

But we're just going to trust the will of

electronics and all the goodness of physics, to say that we're okay for a couple of days, and then we'll do some incremental downgrades or what -- I just, that may, it may even fall within the 48 hours. I don't know, don't remember that detail.

MR. HOFFMAN: Right, right.

MEMBER BROWN: So anyway I'd like at some point, if people are going to talk about that, that would be useful also. Or if the staff would like to answer that later when they're talking, that's --

MR. HOFFMAN: Well, I'll take a stab at it. Now would be the time. The out of service or AOT, Allowed Out of Service Time scheme that is being proposed for St. Lucie in a two, is basically consistent -- I don't want to say basically. It is consistent with the manufacturer's recommendations. If you look back at previous MURs --

MEMBER BROWN: Well, but manufacturers love their stuff.

MR. HOFFMAN: But if you look back at previous licenses that put in MURs, the out of service time, the AOT for the recently-approved St. Lucie Unit 2; for the Turkey Point EPU, they put in an MUR also. The strategy was looked at extensively by the staff and by our INC group, to come up with the AOT times

that you see in the final draft SE.

So St. Lucie isn't an outlier. We're consistent with what's, you know, come ahead of us that may not be sufficient to satisfy you. But we're not doing anything different.

MEMBER BROWN: Well of course, I was not, I'm not a member of the Uprate Subcommittee. If I'd seen this in St. Lucie 1, I would have asked the same questions.

MR. HOFFMAN: Sure. But those, it did get a lot of scrutiny, and the staff maybe, you know, Trace can lean in, because actually we had proposed something a little bit different. The staff came back and tightened up --

(Simultaneous speaking.)

MEMBER BROWN: Well, they changed. Yeah, I felt they changed it a little bit.

MR. HOFFMAN: Right.

MEMBER BROWN: But I didn't see a clear basis, I didn't understand their basis for the change.

MR. HOFFMAN: And you have to understand too, without knowing the hardware, it's not like the entire Leading Edge Flow Meter system is out for a 48-hour period and you're flying blind. It's not that. It's just a very small subset of the system, and you

have 48 hours, similar to what you do with a technical specification LCO. Yes, Todd.

MR. HORTON: Yeah, Jack. If I could add to it. Todd Horton, Florida Power and Light. I oversee the crews. One additional piece that wasn't mentioned by Jack is each night on the mid-shift, the operating crew in the control room will check the output of the older system, the feed water flow venturis, and make adjustments on those to keep the output aligned with the higher sensitivity of the LEFM.

So if the LEFM was to go out of service, the feed water flow venturis will have just been recently calibrated within that 24 hour window with the LEFM.

MEMBER BROWN: Okay, and that brings me back, which following back to the initial question that I asked, which I forgot to come back to. I asked if it was continuously upgraded, and you're saying -- based on your comment, it sounds like the LEFM system, through whatever displays you have, then is used to do your gain adjusts or whatever tweaking you to do the reactor power system, in order to bring those into a normalized or conforming --

MR. HORTON: The older feedwater flow

venturis, the output of those is calibrated each night by the operating crews.

MEMBER BROWN: Again the LEFM?

MR. HORTON: That's correct.

MEMBER BROWN: Okay, and does the old system also feed into the DCS system to do calorimetrics?

MR. HORTON: It will feed --

MEMBER BROWN: Or display to the operator?

MR. HORTON: The output is available to the operators, that is correct.

MEMBER BROWN: Okay. Now does that -- how is that connected into your nuclear instrument system, or whatever generates your reactor trips?

MR. HOFFMAN: It's not.

MR. HORTON: It is not. That is the wide range nuclear instrumentation and the linear arranged nuclear instrumentation that is not impacted by this, that actually feeds into those trips.

MEMBER BROWN: Okay. So you don't calibrate those against -- you don't calibrate those against your thermal calorimetric calibration?

MR. HORTON: That is not something the operating crew would be doing shiftly with the output of the LEFM. The nuclear instrumentation is

calibrated by the Instrument Controls Division with Reactor Engineering, that's done on a different frequency with a different set of parameters.

MEMBER BROWN: Okay. I guess I'm a little confused. Let me hearken back to my old days, and you tell me where I lack understanding. In the plants I was familiar with, we would go to a secondary system calorimetric, determine the actual power being generated by the plant.

Then we would adjust nuclear instrument gain, so that they corresponded to a calibrated point of operation thermally at various, you know, within a pressure, temperature and flow configurations. Then all your trips were then generated from that, and you calibrated the NIs power to the thermal power that's being generated.

MR. HORTON: That's right, you're correct. Those gain adjustments we do do on a nightly basis --

(Simultaneous speaking.)

MEMBER BROWN: Okay. That's what I was asking. So you do those against the calorimetric calculations that were done by the DCS.

MR. HORTON: Right. You're absolutely right.

MEMBER BROWN: So that's how you keep the

plant normalized, not only between alternate and the LEFM, but you also calibrate the NIs every night?

MR. HOFFMAN: Right.

MR. HORTON: That's correct.

MEMBER BROWN: Okay. Thank you very much.

MR. HOFFMAN: And again, now we have two diverse means of measuring feedwater flow. Primary will be the continuous DCS calorimetric count by a Leading Edge Flow Meter. We will still have the calibrated venturis as a backup. They're part of that allowed out of service time in the coordination with the NIs.

MEMBER BROWN: Yeah, I got that. Okay, thank you.

MR. HOFFMAN: Okay.

CHAIR REMPE: But for follow-up action items on that, I think I heard you wanting to know more information about the allowed outage time --

MEMBER BROWN: Yeah. Well, they proposed one thing, and then the staff came through with a brief discussion of no, we don't -- you went too far. So they toned it down a little bit, from what I could --

(Simultaneous speaking.)

MR. HOFFMAN: --tighten it up.

MEMBER BROWN: From what I could see.

CHAIR REMPE: That's another basis --

MEMBER BROWN: I'd like to know the basis for tightening it up and why, if it was needed to be tightened a little bit, why didn't it need to be tightened all the way?

CHAIR REMPE: Sure, okay.

MEMBER BROWN: Even though it's already been done before. Kind of what's the basis for that? So the staff could address that --

MR. BROADDUS: This is Doug Broaddus. We're looking to see if we can, if the reviewer is available to come down and discuss that, and so we'll find some time a little bit later.

MEMBER BROWN: Okay. That would be helpful. Thank you very much.

MR. HOFFMAN: We have the action for the --

MEMBER BROWN: Yeah. I'd still like to see a confirmation of, you know, a functional diagram at some sort that shows that there are no connections anywhere, and that there's no what I would call back door path via whatever the PI system feeds externally, that can work its way back in.

It would just be nice to see a nice knife-

edge break between that and what gets to the operator's desk, as to what they're doing when they're tweaking the NIs all the time, every night.

MR. HOFFMAN: Okay.

MEMBER BROWN: Thank you for your patience, Joy.

CHAIR REMPE: No problem.

MR. HOFFMAN: Okay, moving along. Comprehensive engineering analyses were performed on all affected primary side and secondary side systems, structures and components that are impacted by the proposed EPU. The analyses were performed at the most limiting EPU design conditions.

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 fuel-related safety analyses. Detailed hydraulic analyses were performed for the feedwater condensate and heater drain systems at this bounding NSSS power level.

A thorough review of the secondary side dynamic response to events such as fast valve closures was also performed as part of EPU. An analytical model of the St. Lucie primary and secondary control systems 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 the operating experience for each license application section, including a review of other uprate license applications, the industry RAI database, industry operating experience and INPO guidance.

Next slide. This table provides a comparison of the primary and secondary plant parameters for St. Lucie Unit 2. As Joe Jensen mentioned, St. Lucie Unit 2 was originally licensed in 1983 at a core power level of 2,560 megawatts thermal. An approximate five and a half percent stretch power uprate to 2,700 megawatts thermal was approved and implemented in 1985.

The proposed EPU is identical to that recently approved for St. Lucie Unit 1, and consists of a 320 megawatt thermal core power increase above the current power level of 2,700 megawatts thermal. The EPU thermal design flow remains unchanged from the current value of 187 --

CONSULTANT WALLIS: Can you explain that to me?

MR. HOFFMAN: I'm sorry?

CONSULTANT WALLIS: You give this in gpm?

MR. HOFFMAN: Yes.

CONSULTANT WALLIS: At what temperature is that gallon?

MR. KABADI: That's based on the cold leg temperature.

CONSULTANT WALLIS: So there has been a change, because the temperature's changed? It's the same volume, but it's a different mass?

MR. KABADI: Right. From the analysis point of view, as far as -- you are right. In terms of mass, it will change. The cold leg, this value is based on the cold leg temperature in the safety analysis. That's is correct.

MR. HOFFMAN: Okay. 178,000 gallons per minute per reactor coolant loop, and the Combustion Engineering St. Lucie unit does have two loops. I will note that this reactor coolant system design flow is identical to that being implemented for EPU on Unit 1.

The proposed EPU cold leg temperature is being increased by two degrees Fahrenheit, from a current value of 549 degrees F, to a value of 551 F.

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 identical to the St. Lucie Unit 1 EPU value, and is well below the industry experience for similar PWR uprates.

The EPU analyses have concluded that the existing Alloy 600 program is sufficient to manage potential aging effects at these increased EPU temperature conditions.

CHAIR REMPE: Just to make sure, because I saw differences between the LAR and the SE, you have no net change and you still have 47 degrees across the core, right? I think I have the right number on that. At the core, there's still no net change in the LAR across the core?

The inlet temperature went up, the core outlet temperature went up to 607.9 degree F still, and you guys are holding with those numbers, right?

MR. HOFFMAN: Where is that?

(Simultaneous speaking.)

CHAIR REMPE: Okay, but it's still inlet temperature is 551 F; outlet is 607.9, and those are the numbers you're going with, because I saw different

numbers in the staff's SE.

MR. HOFFMAN: Right, and just to clarify, these numbers that you see here are Westinghouse, what's called PCWG, which is Performance Capability Working Group, consistent methodology that was used in Seabrook, Turkey Point, Point Beach. That's what these numbers represent.

Now for fuel-related analyses, there was an additional margin added, an uncertainty added to those numbers. So the 607.9 is actually what you'd see in the Chapter 15 safety analyses, adding additional uncertainty to the PCWG numbers.

CHAIR REMPE: So when I saw core, different temperatures across the core, perhaps the staff could use some different values?

MR. HOFFMAN: They were really looking at -- I don't know what context that is. That may be in context of Chapter 15, which made the delta even bigger, based on uncertainties that they used in the Chapter 15 safety analyses.

CHAIR REMPE: And again, I'm talking core vessel and vessel inlet and outlet is what I was talking about. Okay, thank you.

MR. HOFFMAN: Correct, yeah. I just want to make one clarification. You know, these are all

analytical numbers. The reality is our best estimate flow is approximately 200,000 gallons per minute per loop currently. That number is not changing. That's reality. That number's not changing for EPU, and when you look --

We call that the best estimate prediction, and when you look at that flow rate, the actual flow rate, the hot leg temperature, the predicted hot leg temperature is 602.6. So that's what we physically expect to see in the field when we implement the uprate, and these analytical values are simply conservative numbers for use in the appropriate analyses.

CHAIR REMPE: Okay.

CONSULTANT WALLIS: These are not realistic numbers here?

MR. HOFFMAN: These are what I'd call, these numbers define the engineering box that we used to do our analyses. That's --

CONSULTANT WALLIS: It would make more sense to me if you said the reality was this, but you know, this may be something else.

MR. HOFFMAN: Yeah. This is just consistent with the way the material is presented in previous EPU license amendments requests, and again,

these are the bounding numbers --

CONSULTANT WALLIS: Well, it gets confusing when you have sort of three sets of numbers.

MR. HOFFMAN: Sure, sure.

MEMBER SKILLMAN: Jack, let me push back a little bit. You say the bogus number for flows, the mass flow rate associated with T-cold at 187,500 gallons a minute. You're thinking flow; I'm thinking reactor coolant pump motor horsepower, and I'm thinking fuel temperatures.

Then you say that number is really not 187-5. It's 12,500 gallons a minute more than that, with a density of T-cold. That tells me that what we might be talking about thermal conductivity degradation might be different than what we're really going to talk about.

So if you're telling me that it's really 200,000 gallons a minute per loop and it's not 187-5, I say to myself what are we looking at here? I'm with Dr. Wallis. Is this a comic book number or is this the real deal?

MR. HOFFMAN: If you look at our technical specifications, thermal design flow is defined in the technical specifications, and the thermal design flow, minimum thermal design flow in the technical

specifications that we have to use to meet all of our safety analyses, that number is 187,500.

That's the number today in the tech specs. That's the number for EPU in the tech specs. There's margin obviously. You want to take what your best estimate flow is, and you want to ensure that you have flow margin in your analyses for uncertainty and what-not, measurement uncertainty.

And again, these numbers are the PCWG numbers that define what I would call the engineering or design envelope for subsequent engineering analyses. Jay, maybe you can talk about the impact on TCD.

MR. KABADI: Yeah, right. I'm Jay Kabadi for FPL. Our actual major flow for St. Lucie 2 is actually in the range of about 405,000 for both loops. So per loop is coming about 202. When you said these flow for the analysis, we account for the amount of plugging we allow, because right now we have two plugging, which is close to probably very, very low number.

MR. HOFFMAN: Zero.

MR. KABADI: And all these analyses are done with ten percent two plugging. So we look at what the floor would be with the ten percent plugging,

and then allow margin for uncertainty and some additional margin, and that's how this flow of 187,500 is set up.

So real flow is much higher, but all the safety analyses which are conservative, if you use the lower flow, we bounded with these numbers. So as long as -- we measured the flow for each cycle, as long as they are a bounded flow, we meet all the safety analysis requirement.

In the real sense, exactly as you said, for the field performance and all, really get much better numbers. So thermal conductivity by the reactor temperatures will be lower than what is analyzed. So then exactly there is some original margin. But since we do these analyses for DCD, LOCA and other things one time, we take the worse conditions and analyze that.

So as long as our flow remains about this value, we meet the requirement of the effects of the LOCA.

MEMBER SKILLMAN: Thank you, understand.

CONSULTANT WALLIS: So if I wanted to make an independent calculation of something, to satisfy myself that something is okay, which number should I use?

MR. KABADI: When we look for our actual operating parameters, we can look at the reactor measured flow, which is done every cycle. We measure that at the beginning of every cycle of the actual reactor cooling system flow.

So if you use that flow and fit into all the thermohydraulic equations, you will get the actual conditions of what the T-cold, I mean what the T-hot temperatures are.

So although, for example, for one specific cycle, you want to do the best estimate of analysis, those numbers are available, based on -- are available in the sense of could be easily generated --

CONSULTANT WALLIS: What would help me in the future or maybe not, if you had a different table which said these are best estimate values.

MR. HOFFMAN: We certainly have those, and again, we just wanted to establish, for example, with this slide --

MEMBER BANERJEE: Can you just supply that, what the 187,500, you know, best estimates.

MR. HOFFMAN: Sure. Steve, do you want to take that? We'll just provide a table of the -- I think we actually have a calculation, and it's a best estimate calculation.

CONSULTANT WALLIS: That would be good.

MEMBER BANERJEE: So if you were looking at the stored energy in the fuel for LOCA, based on 187,500 is what you're doing. That's ten percent --

MR. KABADI: Right, that's correct. So the analysis is done conservatively.

MEMBER BANERJEE: Yeah, conservatively. So what is the difference compared to what your best estimate would be?

MR. KABADI: Yeah. I think actual numbers we'll provide.

MEMBER BANERJEE: Yeah. If you can provide --

MR. KABADI: There will be a few degrees loss.

(Simultaneous speaking.)

MEMBER BANERJEE: -- percent, right?

MR. KABADI: Temperatures will be in the range of at least 600 instead of 606, whatever mentioned here. But actual numbers we will provide.

MEMBER BANERJEE: Okay.

MR. HOFFMAN: I actually have the calculations.

MEMBER BANERJEE: I think that's where I'm --

(Simultaneous speaking.)

MR. HOFFMAN: I'll talk to you on break.

MR. HALE: Jay, this is Steve Hale, Florida Power and Light. I think it's also important to point out when we do safety analysis, we not only use the minimum flow number, but we use a range of temperatures to make sure that we bound the low end and the high end.

And if it's more conservative to run at low temperature, that's the analysis we run, and if it's more conservative to run at a higher temperature, we run it at that.

MEMBER BANERJEE: So we are going to visit this TCD issue later, and the effect on LOCA?

MR. KABADI: That's correct. That's in the afternoon closed session.

MEMBER SKILLMAN: I accept your answer and I appreciate what you have said. Had this slide been titled "Analytical Assumptions," perhaps neither Dr. Wallis nor I would have asked the question.

MR. KABADI: Understood.

MEMBER SKILLMAN: But when they're presented as the actual -- it sounded like they were presented as the actual.

MR. HOFFMAN: Yeah. They're design

parameters.

MEMBER SKILLMAN: We have a tendency to stumble. So thank you.

MR. HOFFMAN: It confuses the operators, because they look and this is not what I see in the plant. But they're numbers that we in Engineering need to use, to make sure we do bounding conservative analyses.

MEMBER SKILLMAN: For analyses?

MR. HOFFMAN: Correct.

CONSULTANT WALLIS: But the trouble is that what's conservative for one thing may not be conservative for another?

MR. HOFFMAN: For another. It makes it, that's the challenge we have, is to make sure we're picking --

MR. KABADI: And we look at it as part of the analysis, like some, for example, fuel liftoff and we use max flow. We cannot use this minimum flow to calculate the liftoff of the fuel.

MEMBER SKILLMAN: We're looking at the same thing. So yep. Thank you.

MR. HOFFMAN: Okay. Any other questions on the parameter slide? If not, we'll move forward. Several EPU modifications shown on this slide have a

beneficial safety impact. For example, the second modification on the list resolves a long-standing low margin issue for St. Lucie Unit 2.

Unlike Unit 1, the control room air conditioning condensing units are cooled by the safety-related closed cooling water system. This design limits the maximum allowable ultimate heat sink temperature, and becomes challenging during the summer months.

The proposed EPU modification upgrades the air conditioning skid to accommodate elevated heat sink temperatures well above that expected during normal plant operation. The last modification on the slide increases the reactor protection system steam generator low level trip setpoint to improve the unit's plant risk profile for beyond design basis events.

The risk impact of EPU was calculated using the St. Lucie Unit 2 internal events, PRA model and the results concluded that the EPU results in a slight decrease in risk or a risk benefit.

MEMBER BANERJEE: So if you go and look at this, install Leading Edge, you're already taking advantage of that by getting your uncertainty down. So in some way, you can double-count it, because

you've already taken that advantage. It's not like if you didn't take the advantage, that would enhance safety?

MR. HOFFMAN: Correct.

MEMBER BANERJEE: But in this case, that's really pushing it too far, to say it supports safety. You're doing what you can to get the benefits of it.

MR. HOFFMAN: Sure.

MEMBER BANERJEE: Right, okay.

MR. HOFFMAN: We believe it's a more accurate way of calculating --

MEMBER BANERJEE: Sure, but you're also getting --

MR. HOFFMAN: --which ultimately gets to NIs and --

MEMBER BANERJEE: Yeah, but you're also taking advantage of it.

MEMBER SKILLMAN: At one point -- you're jacking the power up by 1.7 percent.

MR. HOFFMAN: No question. It is far more accurate then --

(Simultaneous speaking.)

MEMBER SKILLMAN: It just allows you to maintain an equivalent safety posture, not improvement.

MEMBER BANERJEE: And you know, this committee has had continuing debates on the accuracy of these things, because it's very, very tricky and we've sort of finally, after many go-arounds, agreed to this in some sense.

But there are concerns, because it has to be installed precisely. You can't do the calibrations of these, you know, *in situ* very easily. So it's a difficult problem. The staff has taken a certain position. We've agreed to it, but let's not push it too far.

MR. HOFFMAN: Understand.

MEMBER BROWN: Just my reading of the installation and the basis was that you were not doing, using this based on analytical extrapolations, that what you actually tested with the appropriate number of pipe diameters or whatever it is from the terminology is upstream and downstream and where the thing is located, and you actually did a calculation.

MR. HOFFMAN: That's right.

MEMBER BROWN: It was fairly --

(Simultaneous speaking.)

MEMBER BANERJEE: Yeah. Let's not go there. This is a --

MEMBER BROWN: Well, I know. That's why

I didn't, since I figured you had already caved somewhere along the line.

MEMBER BANERJEE: I didn't cave. Graham Wallis caved.

MEMBER BROWN: Okay.

(Laughter.)

MEMBER BANERJEE: This goes back historically.

MEMBER BROWN: But at least it was not an extrapolation. They were doing it based on actually testing their --

MR. HOFFMAN: The actual spools that we put in the field were tested --

MEMBER BROWN: They were testing those in a calibrated facility, to make sure they've got the right data. So --

MEMBER BANERJEE: The Reynolds numbers effects, all sorts of things.

MEMBER BROWN: All that good stuff, yeah, yeah.

(Simultaneous speaking.)

MEMBER BANERJEE: Over and done with.

MEMBER BROWN: Yes.

MEMBER SKILLMAN: I'd like to drop out of the stratosphere for a second and ask one or two

questions.

MR. HOFFMAN: Absolutely.

MEMBER SKILLMAN: When we talked a little bit earlier about NPSH, part of that answer is we've tightened up the tolerances on the emergency diesel generators for the tolerance on frequency and on voltage.

MR. HOFFMAN: That's correct.

MEMBER SKILLMAN: And from my experience, that is a big deal, because it affects every 4160 component in the plant, your ECCS buses. How did you do that? Did you change your governors, or did you just credit what you know is the real experience at load for your EDGs?

MR. HOFFMAN: Actually, those actually numbers, and this came out of a previous NRC inspection, component design basis inspection, and we ultimately corrected -- we had the long-term corrective action to fix the problem from that previous NRC inspection.

If you looked at our original technical specifications, and they're consistent with the rest of the industry, the original frequency, allowed frequency on the diesel was plus or minus two. We've gone to plus or minus one.

So we've tightened up on that and, more importantly, we've done an extensive amount of analyses as part of the EPU project, to look at all the components that are speed-dependent, pumps, valves, and ensuring that in all the safety analyses we can support again plus or minus, depending on which is conservative.

So all that analytical work was done as part of the EPU and I'll call them hydraulic or system analyses. The voltage was tightened up from plus or minus 10 to plus or minus 5, and a similar electrical evaluation was done at all of the bus level, whether it was 41.60, 480, 120, to show that, you know, the pumps actually can operate at minus 25 percent. They're spec'd out and designed to voltage.

MEMBER SKILLMAN: Thank you. Let me just pursue this a little bit further. Have the surveillances been changed in your tech spec for the engines, so that the acceptance criteria for the output reflects the tightened tolerances for voltage and for frequency?

MR. HOFFMAN: As part of the technical specification change package for EPU, those new tightened requirements are in our surveillance requirements.

MEMBER SKILLMAN: Thank you. Let me ask one more. While the spent fuel pool criticality work has been pushed off as a supplement, there is a set of words I would like to ask, because I don't see another place to ask the question.

The wording is the tech spec 561 Alpha 3 is changed from a nominal 8.96 center to center between fuel assembles, to a nominal of 8.965 inches, a five thousandths of an inch change. To those that have handled fuel, you have a hard time finding five thousandths of an inch. If you put them in the racks, you'll never find five thousandths of an inch.

What's with that, please? What is this change?

MR. KABADI: Yeah, I think at this point I can answer. That was the number which was in the current tech spec. Actually, this is a correction. This should have been the correct number in the tech specs. Now whether you could get the tolerance to that, what you mentioned, I cannot answer now.

But the correction to tech spec was changed, mainly because to correct what was in the previous tech spec. Actually, they're not changing --

MEMBER SKILLMAN: So this is an admin change in the tech spec?

MR. KABADI: Yeah. When we, since we were at the time doing EPU analysis, when we found that they actually, I think previous, the current tech spec had a number which is slightly different. So this is right time, and we're redoing all the criticality analyses, and when this number was identified as being this, this will change.

MEMBER SKILLMAN: Thank you.

MR. KABADI: So it is not a real change at the plant.

CONSULTANT WALLIS: Well, is there any point in having a tech spec which you cannot verify, because you can't measure it, because it's too, you know, it's too fine? It doesn't seem to make sense.

MR. KABADI: No. I think what I said, I can answer it now. Whenever this configuration was done, they looked at all the specs to see the racks are laid out and what tolerances it should be. That's the real number that should have been in the tech specs.

CONSULTANT WALLIS: But it's something that you can't verify?

MR. KABADI: Right. Those are the numbers used in the analysis.

CONSULTANT WALLIS: It's used in an

analysis, but you can't verify that it's a reality.

MR. KABADI: No. Well, I did not say that. I did not know how that, when the racks were put in the system, I right now do not have knowledge how those were verified, that are within that spec.

CONSULTANT WALLIS: You have Leading Edge measurement system in your spent fuel pool, which enables you to measure within five thousandths of an inch.

MR. KABADI: We can look at that and see what the spec is. But this is -- we are not changing the actual rack configuration in this criticality analysis. That number was just a correction, and criticality analysis has been done with the same numbers as before. Only changes we did in the criticality analysis were putting slightly higher enrichment and putting more margin in terms of --

MEMBER SKILLMAN: Well, I think we'll get another chance to look at this on the spent fuel analyses.

MR. HOFFMAN: Right.

MEMBER SKILLMAN: But I just want to put a signal in the air that the change from -- a change of 5 mils is a very tight tolerance.

MR. HOFFMAN: I think if you look at the

actual tech specs, it's in the section called "Design Features." So it's not -- it's just a design feature number in the tech specs. It's not a number that we go out and have to verify or validate. It's simply a design feature number in the specs, and again, that's a number that's carried on with additional uncertainties in the criticality analyses.

MEMBER SKILLMAN: Okay, thank you.

MEMBER SCHULTZ: Jack, before we leave this slide, you were in the process of looking at the last bullet with regard to the steam generator low level trip setpoint change, and its impact on the plant risk profile.

I wanted to clarify whether you were saying that this was a major change that with the EPU affected the plant risk profile in a positive way. EPU alone would have affected this in a negative way. So then you made a change.

MR. HOFFMAN: Right.

MEMBER SCHULTZ: And is what you're saying the change that was implemented more than compensates for the EPU change?

MR. HOFFMAN: Yeah. When you look at classical safety analyses, Chapter 15 analyses for EPU, there was no need to change the setpoint. It's

currently 20.5 percent, an error range greater than equal to, and that number could have been defended as part of the EPU.

However, when our PRA folks did their analyses and they were concerned about events such as total loss of feedwater and the amount of inventory that's in the generator for a beyond design basis event and operator timing to initiate once-through cooling, we were able to in PRA space -- we changed an RPS setpoint primarily for PRA, not for safety analyses. We could have kept it as is. But it was a risk benefit, so we made that change, and the new number is 35 percent error range.

MEMBER SCHULTZ: Oh, and that's important. The operator timing changes are real.

MR. HOFFMAN: That's right.

MEMBER SCHULTZ: And so you may be able to support it in safety analysis in some fashion, but the arguments are tougher to make and therefore this change is a good one to employ.

MR. HOFFMAN: And it was risk-driven, not safety analysis driven.

MEMBER SCHULTZ: Understood.

MEMBER BANERJEE: Yu did this with St. Lucie 1 as well?

MR. HOFFMAN: Correct. Same change, consistency between the units. It's actually more critical for Unit 1 than Unit 2 because of PORV sizing.

MEMBER BANERJEE: Right.

MR. HOFFMAN: But again, for operators it's human factors. We want to keep the same numbers.

MEMBER SCHULTZ: And on the point related to environmental qualification, the radiation shielding changes, what is the magnitude of those. Is that a change in program?

MR. HOFFMAN: Well ultimately it affects the programs, because the components are in the program, and what initially happened with the EPU is there was one area in the plant in the auxiliary building that went from a current mild environmental to a harsh environment.

We initially thought that the components, the EPU components in that now had to be evaluated for the harsh environment, and we did detail -- we initially were going to shield those component for more detailed analysis based on distance. Those components still remained in a mild environment.

However, the changes for EQ that we had to make for EPU are the temperature indicators inside

containment. There's an IEEE 323 margin. You want to have at least ten percent margin on dose, radiation dose, and we fell within the ten percent margin. So for EPU, we're replacing two of our safety-related containment, air temperature RTDs as part of the EPU.

So that's the modification. Everything else was shown by analysis to still be within the existing qualification of the components.

MEMBER SCHULTZ: Thanks for the additional information.

MR. HOFFMAN: Okay, yep. Let's go to the next one. For the balance of plant, a number of changes are being implemented in the steam path. The low pressure steam path was replaced during the Unit 2 refueling outage. It was replaced during the last Unit 2 refueling outage, I'm sorry, and the high pressure steam path will be replaced during the upcoming 2012 EPU refueling outage.

A modernized turbine control system, similar to that recently implemented on Unit 1, will also be implemented to replace the existing obsolete system. The main feedwater and condensate pumps will be replaced, and additional modifications to the main feedwater system include replacement of the --

CONSULTANT WALLIS: Can you ask you about this steam bypass?

MR. HOFFMAN: Sure.

CONSULTANT WALLIS: It says that you increased the control system capacity. You mean you've increased the bypass capacity?

MR. HOFFMAN: Yeah, that's correct, and actually we did -- well, we increased the speed too.

CONSULTANT WALLIS: There's no bypass capacity.

MR. HOFFMAN: Absolutely.

CONSULTANT WALLIS: The way it reads, it's as if --

MR. HOFFMAN: Yeah, yeah, yeah. There was both. We actually made a speed change to make the valves respond faster, and we also made a capacity change.

CONSULTANT WALLIS: So you made something bigger in capacity change?

MR. HOFFMAN: Bigger valves, bigger valves.

CONSULTANT WALLIS: Bigger valves, okay. I thought that was it. Thank you.

MR. HOFFMAN: As I mentioned, the main feedwater reg valve internals and actuators are being

replaced with EPU in addition to the number five high pressure and number four low pressure feedwater heaters. Next slide.

CONSULTANT WALLIS: How did you upgrade the condenser?

MR. HOFFMAN: Actually, we did a lot of work on the condenser. We had a lot of experts, subject matter experts come in and do walkdowns, material condition walkdowns of the condenser during past outages. On paper analytically, there's enough design capacity to handle the additional duty.

But the changes we made, we put in tube stakes for vibration concerns due to the higher steam flow, and we also made improvements to the air removal system, which has been an existing ongoing problem.

You know, we expect to have more non-condensables. It was an existing problem, so we just improved that system. So fairly benign.

CONSULTANT WALLIS: You didn't change the tubing at all?

MR. HOFFMAN: No.

CONSULTANT WALLIS: I mean it's the same --

MR. HOFFMAN: Titanium tubes that were replaced many years ago, good performance.

MEMBER SKILLMAN: Getting rid of the additional non-condensables, did you change your air ejectors or change your blend condenser or anything like that?

MR. HOFFMAN: No. The capacity, we had a design problem internal to the condenser, where the pickup points for the non-condensables were not necessarily optimized, and we also had some leakage problems and we -- the capacity of the system was adequate. It was more, you know, the internal configuration of the system, and eliminating flanges, because we had some air and leakage problems.

MEMBER SKILLMAN: So I hear you actually made physical modifications on the condenser including staking?

MR. HOFFMAN: And staking.

MEMBER SKILLMAN: Changing location of suction of air ejector?

MR. HOFFMAN: I'm not -- I'll have to double-check that. I know we definitely made piping changes outside the condenser on the -- maybe Dave, you can -- I'm not. I know we made piping changes outside the condenser on the air removal piping.

MR. D. BROWN: Yeah. What we were looking at is -- this is Dave Brown, Florida Power and Light.

The problems that we were having is where the steam was coming in, where the air ejector pickoff was coming up. What we did is change some of the tray arrangements around that, so that we don't actually pick up steam instead of the air, so that we can actually get a collection of the non-condensables.

So it's not really a major change. It's really just kind of a tray-type change to change what the flow looks like inside the condenser going into the air ejector pickups.

MEMBER SKILLMAN: Okay, thank you.

MR. HOFFMAN: Thanks Dave. Okay, next slide. The heater drain pump internals are also being replaced for EPU and selected heater drain valves, and heater drain valve controls are being upgraded. Similar to St. Lucie Unit 1, the EPU project will also resolve another long-standing low margin issue for Unit 2.

The existing turbine cooling water heat exchangers have marginal heat removal capability at the current plant power level during the summer months, when the ultimate heat sink temperature is elevated.

To resolve the margin issue, the EPU project is replacing these heat exchangers with heat

exchangers having approximately 50 percent more heat transfer capability. Improved materials of construction are also being included as part of this modification.

MEMBER SKILLMAN: Before you jump into electrical, one more plumbing question please. Sentence one is a pair of PORVs and both arms during operation. St. Lucie 2 has two PORVs. I don't know whether they are the same size or different sizes, but one is disarmed during normal operation.

MR. HOFFMAN: That's correct, correct.

MEMBER SKILLMAN: Is this a modification for the EPU, or is this original hardware for this plant?

MR. HOFFMAN: Yeah. A design difference between St. Lucie Unit 1 and 2, again looking at the vintage, Unit 1 was pre-TMI, Unit 2 post-TMI. The PORVs on Unit 2 are much larger than the PORVs on Unit 1, and there was -- this goes back to original design.

There was a concern that if both PORVs opened on Unit 2, due to their size it could become a challenging overcooling event. So we actually have a technical specification requirement on Unit 2 to keep one of the two valves blocked, and that's been carried

on since Day 1.

MEMBER SKILLMAN: Okay, thank you. The real question I had was whether this was an EPU feature or an original design feature. So it's a post-TMI design feature?

MR. HOFFMAN: That's correct.

MEMBER SKILLMAN: Got it. Thank you.

MR. HOFFMAN: Yep, okay.

CONSULTANT BONACA: Is the auxiliary feedwater system a redundant system?

MR. HOFFMAN: Yeah. Similar to St. Lucie Unit 1, the Unit 2 auxiliary feedwater system has two 100 percent motor-driven pumps. That's a current -- the way we characterize the system currently is it's two 100 percent motor-driven pumps and one greater than 100 percent steam-driven pump, and for EPU, that same design logic has been validated.

The motor-driven pumps remain 100 percent each, and the turbine-driven pump is a greater than 100 percent capacity pump. Did a lot of analyses on Unit 2 in particular regarding aux feedwater performance, decay heat removal capability and again, just because of the design and the diversity of the system, you know, it was not an issue for either Unit 1 or Unit 2.

CONSULTANT BONACA: Okay, thank you.

CONSULTANT WALLIS: Did you make changes in piping in response to FAC, flow-assisted corrosion?

MR. HOFFMAN: Yes, we did.

CONSULTANT WALLIS: Did you change the materials for some pipes?

MR. HOFFMAN: Oh absolutely. Yeah, yeah. We did, just a handful of what I'll call -- in the heater drains primarily on both Unit 1 and Unit 2, and whenever we make a piping change for FAC, we will upgrade to the chrome moly piping. So we minimize the inspections and potential for future replacements. So there were physical FAC modifications.

CONSULTANT WALLIS: Then you extrapolate behavior in the future with EPU?

MR. HOFFMAN: Absolutely. It's already been done and factored into the new program.

CONSULTANT BONACA: Since you made so many changes in the system, do you use the PRA in any way as a means of providing insights on the design of changes?

MR. HOFFMAN: Yes, every modification. Early on when the PRA work was initiated, each modification was looked at, as whether it provided -- whether it was risk-neutral, risk-beneficial or a

detriment to risk, in all aspects, whether it was an internal or an external event.

So that was all, you know, what I'll call baked into the original PRA, and it was subsequently validated based on, you know, when we started, some other little mods came out of the woodwork, and that PRA work was validated again once our modification list was finalized.

CONSULTANT BONACA: Thank you.

MR. HOFFMAN: Okay. On the electrical side, the main generator stater was rewound and the rotor was replaced during the last Unit 2 refueling outage. During the upcoming EPU outage, the main generator hydrogen pressure will be increased to 75 psi. These modifications will allow the main generator rating to be increased to a value suitable for the uprate.

An additional EPU electrical modification is being implemented to resolve another low margin issue. Currently, there is limited margin between the degraded voltage relay setpoints and the calculated bus voltage during the limiting electrical loading event.

For EPU, a number of electrical modifications are being implemented to increase this

voltage margin, and this is similar to what we did on Unit 1 also. So unless there are any questions for me --

MEMBER BROWN: I have a question of understanding.

MR. HOFFMAN: Sure.

MEMBER BROWN: Station blackout, the coping time that you all advertise, what you calculated and the staff evaluated remains at four hours. This is a two unit site. Since I'm not familiar, I don't remember the St. Lucie 1 set-up. But do each of the units have their own switchyard, or do they share a common switchyard? I don't remember from the earlier St. Lucie.

MR. HOFFMAN: It is a common switchyard with bays.

MEMBER BROWN: So the multiple, the two, the independent feeds, off-site feeds come into the common switchyard setup?

MR. HOFFMAN: That's correct. But the diesels between both units, you know, irrespective of the station blackout coping requirements --

MEMBER BROWN: They have independent diesels. It's not a shared diesel?

MR. HOFFMAN: Two diesels on each unit,

and we do have cross-connect capability.

MEMBER BROWN: You talked about a cross-tie.

MR. HOFFMAN: Right.

MEMBER BROWN: Now one of the reasons, again this is an understanding; I just want to make sure I understand this, okay, is that one of the bases for you all's SBO is that you have natural circulation that will allow you to maintain decay heat removal capability for that four hour coping period.

I'm assuming, then, that that's dependent. You still have to operate certain equipment, but that's dependent upon your battery DC power sources via whatever inverters you have. So you're still, whether it's -- that's just your method, but you're still fundamentally limited by the battery capacity, if you exceeded the four hour coping period.

MR. HOFFMAN: That's correct.

MEMBER BROWN: And then you would be, have to fall into the ability to do the cross-tie, and assume that the diesels from the other side, assuming the other side is shut down, that you then, and you haven't got off-site power back, you'd have to do that.

MR. HOFFMAN: That is the SBO.

MEMBER BROWN: Is my understanding --

MR. HOFFMAN: That's correct. That's the SBO licensing basis for St. Lucie Unit 2, and we did a detailed Chapter 15-type analysis for EPU, to show that again, for that four hour coping time, we could maintain the --

MEMBER BROWN: Yeah. No, I read it. I just wanted to make sure I understood the other connections, since I didn't have any of that information.

MR. HOFFMAN: Okay.

MEMBER BROWN: Thank you.

MR. HALE: Before we leave Jack's presentation, we do have an answer on your cybersecurity question, with regards to information flow.

MEMBER BROWN: Do you have a picture?

MR. HALE: Huh?

MEMBER BROWN: Do you have a picture?

MR. HALE: Don't have a picture, but --

MEMBER BROWN: So the thousand words will replace a simple diagram, right?

MR. HALE: Well, the DCS is classified in our system as a high level security computer system, and the interface between the DCS and PI, as a wall

basically, a one-way diode. They call it the dama-diode (ph). It's a deterministic device that does not allow communication to flow from the PI system back to the DCS.

MEMBER BROWN: Okay. So when you say a one-way diode, let me make sure I understand one thing. There are one-way diodes and then there are one-way diodes. Some one-way diodes are devices which are reconfigurable to be two-way if you so desire.

Several methods to do that. Some can be done externally via remote mains; some have to be executed at the device itself by manual means. So my question is what kind of one-way diode? Even if it's deterministic, it can still be executed either way.

MR. HALE: It's the latter, the one that would require -- you would require to go physically to the hardware to make changes to a diode such as that.

MEMBER BROWN: Okay. So somebody externally cannot do that via remote access to some software package somewhere?

MR. HALE: Exactly.

MEMBER BROWN: Okay. Let it be written and let it be recorded. Thank you.

MR. HALE: All right, and then we do have some of the best estimate data.

MR. HOFFMAN: I've got the calcs, Steve. I'll share the calcs.

MR. HALE: Okay, thank you.

MR. HOFFMAN: Yeah. Okay. Unless there are any other questions for me, I'd like to turn the presentation over to Jay Kabadi, who will discuss the EPU fuel-related analyses.

CHAIR REMPE: So we're running about 20 minutes behind, just so everyone's aware. So go ahead.

Fuel and Core Design

MR. KABADI: Okay. My name is Jay Kabadi. I'm manager of Nuclear Fuel for Florida Power and Light. In the next few slides, I'm going to present what the EPU considerations are for fuel design and cooling towers. This slide presents for EPU, we did not have to make any changes to the fuel design.

We will continue to use the Combustion Engineering 16 by 16 fuel design, which we have been using for past several cycles. It has an Incanel Top Grid design, which we implemented mainly to provide additional margin to grid-to-rod fretting. Our pin burnup and assembly burnup limits remain unchanged.

MEMBER SCHULTZ: Jay, what are those limits for the rods?

MR. KABADI: I think we have real limit is on the pin burnup, and that is 60,000. Assembly burnup is mainly we maintain to ensure that pin burnup is not limited; there is no real hard limit --

MEMBER SCHULTZ: There's not an assembly burnup limit --

MR. KABADI: That is correct.

MEMBER SCHULTZ: --that's designated. Thank you.

MEMBER BANERJEE: Is this fuel being tested? This is a sort of a question which is related to GSI-191. Just for informational purposes, it is being tested for downstream effects?

MR. KABADI: My understanding is when there's a downstream effect, the testing is set up so that it covers all the fuel assembly types. I cannot, I do not know exactly how this product is designed, but the intent of the testing was to make, with the final results, applicable to all the fuel --

MEMBER BANERJEE: Because as you know, there are tests which have been done with Westinghouse and AREVA fuel.

MR. KABADI: Right, right, right.

(Simultaneous speaking.)

MR. KABADI: Right, and this is

Westinghouse. This is the Westinghouse fuel.

MEMBER BANERJEE: Oh, this is the Westinghouse fuel.

MR. KABADI: Right. This is the Westinghouse fuel. Now there were changes because of regional Combustion Engineering. So this is covered under Westinghouse program.

MEMBER BANERJEE: So it's substantially the same design?

MR. KABADI: Right. This is a period of design by the licensee, and not the one which is at Turkey Point and all. Right now, it is Westinghouse, because they put it together, but the design is the regional CE design.

MEMBER BANERJEE: I'm so confused by all this.

MR. KABADI: Westinghouse actually right now is like what you call old or traditional Westinghouse, this 16 by 16 design is not one of the original Westinghouse designs. This was the CE plants 16 by 16 design. When they merged, the same design is carried over. So there is no change to the fuel design before and after CE or Combustion Engineering --

MEMBER BANERJEE: Let's be more direct.

What is the design that's being tested under this program right now?

MR. KABADI: GSI-191? Well, I cannot detail. Only thing what we were --

MEMBER BANERJEE: It's not this, right?

MR. KABADI: It should be included as part of the overall program, the final results to be applicable to all the designs.

MR. HOFFMAN: We'll validate that.

MR. KABADI: Right. We can validate what is exactly --

MEMBER BANERJEE: Yeah. Just give me this --

(Simultaneous speaking.)

MEMBER BANERJEE: I know it doesn't impact you for this EPU, but --

MR. KABADI: That's okay. We can look and see whether this particular design is included in the testing.

CHAIR REMPE: But isn't the argument that was responded to in RAI is that the EPU doesn't affect --

MEMBER BANERJEE: Thermal decay heats, right.

CHAIR REMPE: They're basically saying

that it didn't affect the zone of influence that they were calculating.

MEMBER BANERJEE: It's not the zone of influence. You've got to push most coolant through the core to keep it cool.

CHAIR REMPE: Yeah, okay. That was what the staff --

MEMBER BANERJEE: Does that mean the ultimate if you start to block with downstream effects.

CHAIR REMPE: Okay.

MEMBER BANERJEE: You're having 12 percent more power, right?

CHAIR REMPE: Yeah, okay. But I was just going to take it what's been reported in the SER, so I was just kind of wondering.

MEMBER BANERJEE: They can be, let's say in the GSI-191 evaluations, you take EPU into account. That's the idea, right, and that's what every applicant is saying, before going for an EPU. But to say it doesn't make a difference is pretty hard to defend, I would say. You've got 12 percent more decay heat or something to deal with, right? Does that make any sense?

CHAIR REMPE: It makes sense, but it's

just the reporting that they had in their RAI.

MEMBER BANERJEE: Go ahead.

MR. HALE: This is Steve Hale, Florida Power and Light. Yes. If you'll remember, Dr. Banerjee, at both Point Beach and Turkey Point, we essentially followed the same approach with GSI-191.

It was being handled as a separate, you know, generic licensing action. But we've made sure that anything we're doing, any EPU falls within the bounds of what we're doing under GSI-191.

MEMBER BANERJEE: Well, you have to take into account the higher decay heats.

MR. HALE: That's true.

MEMBER BANERJEE: Sure, okay.

MR. HALE: But all of our efforts related to GSI-191 have already taken the EPU into account.

MEMBER BANERJEE: Right. I was really asking if the fuel designs are encompassed by the downstream effects testing going on. So --

MR. HALE: I can't answer that. We'll have to find somebody to respond to that question.

MEMBER BANERJEE: Okay.

MR. KABADI: From fuel design perspective, we have, we developed several transmission cycles for EPU to come up with the parameters that we can use in

the safety analysis.

But in general, core design limits do not change much for EPU, which is a total integrated radial peaking factor, we reduce from 1.7 to 1.6, again moderating some of the analysis to offset some of the impacts of higher power.

We will remit this reduced limit and the extra energy demand to higher power by changing our peak size number of assemblies, along with some arrangement placing the absorber rods in the locations. But our general loading pattern configuration remains similar. So there is no major change to the core loading plan.

MEMBER SCHULTZ: With the radial peaking factor affected not only by the EPU power change, but also by the thermal conductivity degradation, which we'll discuss later?

MR. KABADI: Actually, when we started this EPU analysis, thermal conductivity degradation was actually not where it is right now. There was not too much consideration directly given. But in general, any time your peaking was down and the power was down, it helps thermal conductivity.

But it was not the initial decision on making this lower; it was strictly based on fuel

performance and the DNB considerations.

MEMBER SCHULTZ: So this change was done and not affected by the thermal conductivity degradation impact?

MR. KABADI: That is correct.

MEMBER SCHULTZ: Thank you.

MEMBER SKILLMAN: Jay, did you change the cycle length in this application, 18 months to 24 months?

MR. KABADI: No. We are still following 18 month cycles.

MEMBER SKILLMAN: I understand you're on 18 month cycles. Thank you.

MEMBER BROWN: Let me ask, it's a simple-minded question. I'm not -- if I'm completely off the wall, just tell me. So you wanted to maintain margins to fuel design limits, and in order to do that, you reduced one of your peaking factors.

But I mean so previously your analysis said okay, if I'm at a certain point, I've got peaking, radial peaking factors of 1.7. Now we said oh, now we're going to assume a lower number. Therefore now, I will calculate that I don't get any closer to my fuel design limits than I did before. Is there a basis for saying I can reduce my radial

peaking factor? Is that --

MR. KABADI: No, I think this is when we did the code design on the analysis, this was actually evaluated.

MEMBER BROWN: It's a similar core. I mean did you all change the core in this case? I didn't get that out of the reading.

MR. KABADI: No, I think that -- so when we designed the core, that's when we had to put the assemblies, and the number of assemblies that reduces the peaking factor, which is --

MEMBER BROWN: But you made a change in the arrangement or the setup --

MR. KABADI: I think that remains similar, in the sense that number of assemblies, fresh assemblies will go up. But we typically follow for St. Lucie 1, in-out-in type configurations. So we put all the peripheral assemblies in as --, and the fresh and whatever turbine go inside.

So that pattern remained the same. But how many fresh we used slightly increased because of this, to reduce the peaking. So we are using currently in the range of 72 to 76 assemblies.

CONSULTANT WALLIS: So you are flattening the --

MR. KABADI: That's correct. So for EPU --

MEMBER BROWN: And so you did something physically --

MR. KABADI: Correct, correct. So we'll be using --

(Simultaneous speaking.)

MEMBER BROWN: --but where you laid out the --

MR. KABADI: That's exactly right. We are using --

MEMBER BROWN: For whatever you did. So you would flatten the power sum and reduce the radial --

MR. KABADI: That's correct.

MEMBER BROWN: So there's a basis for saying I can go to a reduced number?

MR. KABADI: That's correct.

MEMBER BROWN: That's what I was asking.

MR. KABADI: That's right, exactly right. We did some --

CONSULTANT WALLIS: We're not saying that they actually will go to a reduce peaking --

(Simultaneous speaking.)

CONSULTANT WALLIS: That's just an

assumption.

MEMBER BROWN: I understand. That's just, I mean.

MR. KABADI: And we did design with these, to see that we can meet those --

MEMBER BROWN: I just want to make sure you just didn't reduce it because it was fun to reduce it for convenience sake, that's all.

MEMBER SCHULTZ: It was required to be reduced, and you spoke to it here, Jay, but it's not in the slide. But the feedback size goes up.

MR. KABADI: Yeah, right.

MEMBER BROWN: Okay.

MEMBER SCHULTZ: In order to accommodate and achieve the high power.

MR. KABADI: And as I mentioned, from 72 to 76 right now you get --.

MEMBER SCHULTZ: Jay, one more thing. You had burnable absorb replacement here. With regard to that, is that a dramatic change that's been implemented by Westinghouse?

MR. KABADI: No. It's really for burnable absorber we had following the same type of strategy. We go anywhere from 8 to 20. We had gad rods and eight percent of that is very similar, around eight

percent.

MEMBER SCHULTZ: That's not a change. That's under the normal approaches that have been used with regard to the placement of --

MR. KABADI: That's correct. Only change would be number of feeds to go out.

MEMBER SCHULTZ: And you're not implementing any additional changes with respect to gad loading, changes from what you have done in the past?

MR. KABADI: Exactly. No changes to the gad rod --

MEMBER SCHULTZ: The same choices you've used in the past, that you have available in --

MR. KABADI: Exactly. That is correct.

MEMBER SCHULTZ: Thank you.

MR. KABADI: Other limits which are important from core design perspective, mainly the shutdown margin and MTC (ph). Those limits also are met for EPU. So we don't have, we did not have to make any changes to those. Now as far as gadding shutdown margin and improving the boron delivery capability, we are, however, increasing the boron concentrations in all the tanks, RWD.

Also the safety injection tanks and also

in the boric acid make-up tanks, and those are tech specs changes which are covered in the EPU LAR.

Going to the safety analysis, there are no major changes done in terms of what methodology we have used for the analysis. We continue to use the same methods for small-break and large-break LOCA. RETRAN is used for non-LOCA, which is what we currently use.

Only change is we have in the current analysis for tube rupture, we have not transitioned to RETRAN, but as a part of the EPU, even the tube rupture analysis was done with RETRAN. But all these codes and the VIPRE was used in the current V&V analysis.

MEMBER BANERJEE: So these are, some of these are very old codes, right?

MR. KABADI: Those are actually old, but the current --

MEMBER BANERJEE: They're still approved, that's what you're saying?

MR. KABADI: Approved, plus the latest in the sense of the current from the CE plants for these. For example, RETRAN is Westinghouse's current method for non-LOCA.

MEMBER BANERJEE: No. But let's look at

CEFLASH.

MR. KABADI: Right. So that is the Westinghouse Appendix K small-break and large break current method for CE plants.

MEMBER BANERJEE: So your -- in this case, unlike St. Lucie 1, you're going to use Appendix K methods?

MR. KABADI: That is correct. We did not transition to realistic or best estimate for large break. So right now, Westinghouse, ASTRUM and other methods have not been applied to any CE plants. So we may in future take that on.

But right now, based on these -- if you're engaged in a big project event and are using Appendix K, we found that we can meet all the limits with Appendix K. So we did not transition, because that would require a lot of benchmarking and all that stuff to be done.

MEMBER BANERJEE: Okay, and you took TCD into account?

MR. KABADI: Right, and that's something where we have a discussion later in the EPU, when this project started. As I mentioned, we started without DCD like it is right now, but we later on did include and evaluate and see what the impact is, and we'll

talk this afternoon on that DCD impact.

Okay. Some of the key changes which are done for the safety analysis is from the code design point of view actually, which is reduced from 1.7 to 1.6, and the way we do the safety analysis is we try to hold a conservative assumptions, so that planned operations don't get restricted by some of these inputs.

For example, we use all the plant bounding operator parameters, include the uncertainties, and going all the way to the limits of that operation.

CONSULTANT WALLIS: Have these changed as a result of the EPU, or are these the same conservative assumptions as before?

MR. KABADI: Assumptions are same. Only the values will be changing.

CONSULTANT WALLIS: So you did change the values as a result of the EPU?

MR. KABADI: Like the inlet temperature we mentioned. It goes up from 549 to 551.

CONSULTANT WALLIS: Okay.

MR. KABADI: So that is one thing. Other thing will go on the next slide that we show, some of the tolerances on the valves will increase. But the method, in terms of putting --, is about the same.

Yeah. These are some of the changes that help and the same time consistent with our EPU, tech spec changes and other changes we are doing as part of the EPU analysis. Uncertainty goes down from 2 percent to .3 percent, and we talk about that.

Tube plugging, several analyses in the past have 30 percent tube plugging. Not all, but some of the analyses are 30 percent. We are making it all ten percent across the board for all the safety analyses. Tolerances on both --

CONSULTANT WALLIS: What's the basis for ten percent? Is this just a guess of some sort?

MR. KABADI: Ten percent, the way we decided ten percent is we looked at the current flow, what we have, and now we saw how much margin we have, and we generated flows for different tube plugging levels, and we assume that is what is the value that most appropriate to go with.

CONSULTANT WALLIS: What's the reality? I mean you say you're assuming ten percent?

MR. KABADI: Yeah. Right now --

CONSULTANT WALLIS: The reality is what one or two percent or something? What's the reality?

MR. KABADI: Much less than that.

MR. GIL: This is Rudy Gill, Florida Power

and Light. Yeah. Our current number is for the generator that has the most, is a quarter of one percent.

CONSULTANT WALLIS: And the experience with other plants with similar steam generators?

MR. GIL: Typically, the ones that I'm familiar with, that are the replacement type steam generators are also at the very low numbers. I think the only ones I know that have higher percentages are the once-through steam generators that we know have had some issues.

CONSULTANT WALLIS: So this is a number which is convenient, which is much larger than all the experience? There's no real basis other than that?

MR. KABADI: Yeah. I think other than like Rudy mentioned, about similar but -- like St. Lucie 1. We replaced the generators in 1999 time frame, and we have still less than, much less than one percent plugging there.

CONSULTANT WALLIS: So you could have assumed five percent or something like that, maybe wished --

MALE PARTICIPANT: Had to pick a number.

MR. KABADI: Right, and that's why we did some studies to see how much flow, minimum flow we

need for meeting the safety analysis and what we can accommodate in terms of plugging and decided ten percent is the --

CONSULTANT WALLIS: It could accommodate ten percent.

MR. KABADI: Yes. There were other changes to the boron concentrations in the three tanks that are included in all the analyses, where they are important.

CHAIR REMPE: On the steam generator tube plugging, if you for whatever reason were at ten percent, how much margin is -- I mean are you, is that the most you can accommodate based on your analysis, or is there still more margin?

MR. KABADI: Yeah, I think on the next few slides when I present some of the analyses, you will see that analyses has some margins and all the analyses support ten percent plugging. So there is a -- we didn't want to go all the way to the actual limit of all the accident analyses. So there is some margin to the accident analyses.

CHAIR REMPE: Okay.

MEMBER BROWN: Before you leave that one, go backwards, please. The main steam stop safety valve relief tolerances you've now moved from values

you show in here, and I guess I walked away from the one justification for it was that the vendor says his valve is designed to a plus or minute three percent tolerance to hold that, as opposed to your previous tolerance of plus, what you were using on an as-found evaluation basis or check basis, of plus one/minus three.

So now if you go out and you find, if you walk out and you find it's a plus three, you say fine, we're good to go, and away we go. So it may have changed from the last time, but there's no -- I mean it sounds like it's a convenience thing just to minimize adjustments to the steam safety valve.

MR. KABADI: No. I think our tech specs as left setpoint doesn't change. That is still plus one percent. So even if you find, as found three percent, when we start the plant --

MEMBER BROWN: I understand what you find. But if you find it at three, that's an acceptable as-found condition. So you don't have to do anything.

MR. HOFFMAN: Right, and just a couple of clarifications. The plus or minus three percent is the classic ASME --

MEMBER BROWN: I got that out of your write-up.

MR. HOFFMAN: Right, and these numbers that Dave's referring to are really driven by the accident analyses, the over-pressure analyses. That's what dictates, you know, how high you can go primarily, and one thing again. This is a chance for us to get --

MEMBER BROWN: Okay. You're saying that three percent is only used in the analyses. Now when you go out and you do your calibration checks or you do your safety valve trip check, if it was at plus two percent you would reset it, because the tech spec still says plus one percent when you get to the as-found?

MR. HOFFMAN: That's right.

MEMBER BROWN: That's not what the LAR says. It says "as-found value was changed from" -- one of the documents.

MR. KABADI: Right. I think that is the value when the valve got tested.

MEMBER BROWN: So if you go out and if you do a test to verify the operation of your steam safety valves, if it comes in at plus 2.999, you can walk away and say we'll wait until the next time we test it. We're happy as a pig in a mud wallow here.

MR. KABADI: Yeah. That will tell them,

the 2.9 or whatever you find that is covered by the accident. But when they're as-left values, it still has to be plus one. So I'll have to be brought back to within plus one. This is the -- during the, there is some -- during the cycle when they test the valve, and if we analyze with one percent, and the value is found two percent, then it will be outside the analyses.

So we have to do some operability assessment for those. So this one allows that flexibility, that if the value is found outside that, then that is in the analyzed event.

MEMBER BROWN: All right. Your LAR says MSVs with a nominal setpoint of 1,000 psi, the as-found setpoint tolerances are being changed to plus or minus three percent, the as-found value.

MR. KABADI: Right.

MEMBER BROWN: Which to me means that if I find the value within that range, I don't have to do anything until I go run that test the next time and find out that it exceeds that value.

MR. KABADI: I think below that, there is a surveillance requirement that says the valve has to -- no, not --

MEMBER BROWN: No, not tech specs.

MR. HOFFMAN: It's in the technical specifications, not in the text of the LAR. We can show you the tech spec page.

MR. KABADI: Tech spec mentions that, that you have to set it within one percent. I don't know whether that page --

MEMBER BROWN: When you reset it, but as -- okay, I'm really not understanding.

MR. HOFFMAN: We can't walk away from it. The plus three percent allows us to accept the as-found test in analytical space, but our technical specification will not allow us to walk away from the valve at plus three percent. We have to reset it before we walk away and leave it as left at plus one percent for the next operating cycle.

MEMBER BROWN: Okay. Let me be very, make sure I understand this now. I'm operating along, and I come up to whatever your periodicity is for checking the setpoint of your steam safety valves. You run your tests and it comes out two and a half. Do you have to reset it based on that, and go back because of some other document in the tech spec, or is that the as-found value, and it's within plus or minus three and you don't have to do anything?

MR. KABADI: No, we have a --

(Simultaneous speaking.)

MR. KABADI: --during the outage time, once you have that, and then the next time it starts, we have to make them. All that will be brought back into one percent.

MEMBER BROWN: If they exceed one percent on the plus side, they will be brought back to one percent?

MR. KABADI: That's correct.

MEMBER BROWN: Then I don't really understand why the words "as found" are used.

MR. HALE: Hi. This is Steve Hale, Florida Power and Light. That's fairly standard nomenclature like for instrumentation and that sort of thing. The as-found condition is when you go out and test it, you know, you want to make sure that the valve is within those bounds when you go out and test it, okay.

As-left is where you leave it. So if you found it above one percent, the as-left tech spec says you've got to bring it within one percent. So as found says that hey, it's within the range that we expected it to be in, okay, and you certainly want to make sure that at that as-left condition you're within your safety analysis. But we're also required by tech

specs to reset it.

MR. HOFFMAN: Steve, maybe on a break we can pull that tech spec page.

MEMBER BROWN: Oh no. I believe you.

CHAIR REMPE: You're okay?

MEMBER BROWN: Yeah. I believe what you're -- I'm not questioning the fact that that's set. It's the terminology that I -- all I'm trying to establish is when I first read it, it sounded like now I should walk out and see the valves at a value greater than one percent, and say I passed my test now, because I'm at less than three.

If you're required by some other thing to go reset it to the one percent, and all you're saying is I don't have to submit a report to the NRC because I didn't exceed the plus three percent, I don't know who you have to submit anything to.

MR. KABADI: No, that's right.

MEMBER BROWN: I guess before you would have had to submit something if you found it at two and now you don't. You just go reset it to one is my understanding.

CHAIR REMPE: Is everybody okay?

MEMBER BROWN: I'm fine.

CHAIR REMPE: Okay. Let's go.

MEMBER BROWN: Thank you. Sorry. Unfortunately, I read this stuff and --

CHAIR REMPE: Okay, good. Okay.

MR. KABADI: Next slide. Yeah. We talked about this before. As I said, there are no changes to the methodology we use except in tube ruptures we just RETRAN.

This slide, next we will present some of the reasons for the EPU. Now in the RCS flow, decreased category. The limiting events are loss of flow and the locked rotor, and one of the things to note here is the criteria which is mentioned here, like loss of flow 1.42, that is actually a safety analysis limit. We actually have margin built into that, roughly about eight to ten percent.

So when our diesels show 1.444, it is actually beyond what we set as a safety analysis limit. The actual core relation limit is something in the range of 1.33, and that's our actual design limit. So the way the Westinghouse methodology works is they embed some margin and say okay, although the design limit is 1.33, we'll put a safety analysis limit as 1.42, and unless needed for some events, then we'll lower that.

So there is some margin built in in all

these MDNBR limits. So for both locked rotor and loss of flow, we meet all the acceptance criteria for locked rotor. For example, we'll use 19.7 percent fuel failures in our dose calculations. We have no failures in the actual analysis done.

In the peak pressure, our limiting event is the loss of condenser vacuum, and the peak pressure is .69 psia, which has significant margin to the limit. In the new event analyses that we did as part of the EPU, was both in feed line break and loss of feedwater, for the longer term AFW adequacy type analyses, we did like Chapter 15-type assumption to confirm that AFW has enough capacity to have RCS not do subcooling.

So this is a new subset of the regional analysis, what we did as part of the EPU. This is based on some of the staff review and there's a part of some of the request of information we requested.

Next slide. Yeah. Feed line break for St. Lucie 2 is also analyzed in the shorter term, for break sizes, to see the peak pressure in both in the larger breaks and the smaller breaks meet the acceptance criteria with sufficient margin in there.

Steam line break is the other limiting event from cooldown considerations, and as shown on

this slide for both, and V&V and the fuel melt, we have no fuel failures. So the dose consequence analyses remain well-bounded.

CEA withdrawal, this is one of the place where that limit, 1.26 which is mentioned, that has a margin built in significantly in there. The real design limit is in the range of 1.14. So we have sufficient margin in there, and the final result shows that the V&V margin is something like ten percent or so.

For CEA ejection, we analyzed the event for a more restrictive 200 calories per gram criteria. Our analysis shows margin to that, with more than 40 calories per gram, and other limits suggest V&V and field melt for CEA ejection as not limiting and we meet the criteria for EPU.

CONSULTANT WALLIS: And with all these, you do something about conductivity degradation in the fuel?

MR. KABADI: Well, we'll talk a little bit about that later. But yes --

CONSULTANT WALLIS: In that analysis, you take account of that?

MR. KABADI: Right. But a lot of these analyses were like the center-line melt and always

considered, and we'll talk this afternoon how --

CONSULTANT WALLIS: That's included in this table here somewhere, that how it's --

MR. KABADI: Right. How that, why that limit is acceptable. We'll talk this afternoon, that with the thermal conductivity degradation, that's okay. Those limits we'll talk a little bit this afternoon.

MEMBER SCHULTZ: Jay, could you go back one slide?

MR. KABADI: Uh-huh.

MEMBER SCHULTZ: On the CEA ejection, just can you give more information related to the rods in DNB and what you're showing here, or will we discuss that in more detail this afternoon?

MR. KABADI: No. Rods in DNB, Westinghouse, the way the Westinghouse methodology right now works is that they have done some generic calculations, put in some bounding parameters in terms of ejector rod failure, and the coordination they use for all that. St. Lucie 2 specific EPU parameters were compared to that and found to be significantly lower.

The generic analyses has shown that the amount of rods or number of rods in failure are much

less than ten percent. So by doing a comparative-type evaluation, that was concluded that the number of rods in the NBR well below what is used in the --

MEMBER SCHULTZ: So it was comparative parameter evaluation, parametric?

MR. KABADI: That is correct.

MEMBER SCHULTZ: To demonstrate that the analyses essentially didn't need to be repeated --

MR. KABADI: Right, that is correct.

MEMBER SCHULTZ: --you know, with the conditions of EPU.

MR. KABADI: Right, particularly since the generic analysis covers the limits of all those analyses.

MEMBER SCHULTZ: But specifically was there an evaluation related to -- was there an analysis related to fuel melt, or was that an evaluation also?

MR. KABADI: Fuel melt? I think I wrote this specific analysis and Jessica, are you responsible?

MS. TATARCZUK: For our CA ejection event, the rods and DNB parameter of less than 9.5 percent. That was the generic analysis that Jim was speaking to, that we had our data for the EPU, and it was

actually vastly bounded by the WCAP that was done, the generic analysis.

So we did that. But we did use that as input our state points, which come back. For the other parameters, actually they did actual data evaluation for, the rods and DNB was the portion that was the portion that was bounded by the generic analysis.

MEMBER SCHULTZ: Thank you.

MS. TATARCZUK: Sorry, just one other thing. I'm Jessica Tatarczuk from Westinghouse. I didn't introduce myself.

CHAIR REMPE: Yes, thank you.

MR. KABADI: Next slide. Yeah. You have the difference between EPU and non-EPU on that, but certain margins don't change and there is not too change to the plant configuration. One event which was done in two subevents, which was inadvertent opening of the PORV. Typically, that event was analyzed only for DNB, and that has significant margin for EPU.

CONSULTANT WALLIS: Now on this slide, the pressurizer volume is 1519, is that right?

MR. KABADI: Right.

CONSULTANT WALLIS: It doesn't say so.

MR. KABADI: Oh, okay. Yes. Pressurizer full volume 1519, and that inadvertent --

CONSULTANT WALLIS: So you're saying that the pressurizer does fill if no one does something, is that right?

MR. KABADI: In 20 minutes, the operators --

CONSULTANT WALLIS: At the bottom.

MR. KABADI: Right, and that is the same as what our current analysis is done then. But now for the inadvertent opening of PORV, that's where we analyze again for the pressurizer fill, and that pressurizer fill event for St. Lucie 2 comes out about three minutes, and that is what the operators have to take action to close the block valve or to --

CONSULTANT WALLIS: The operator has about three minutes to close the block valve?

MR. KABADI: For the inadvertent opening of PORV, and that is a new, what I call a new event which builds on the staff review. We have to also do for St. Lucie 1 and --

CONSULTANT WALLIS: Is time significantly less than it was before the EPU?

MR. KABADI: No. This event was not analyzed --

CONSULTANT WALLIS: Was not analyzed before.

MR. KABADI: Yeah. This is a new, it came as a part of the staff review and now, for those of you who were here for St. Lucie 1, that was also talked about as being redone for St. Lucie 1 also, and St. Lucie 1 gets larger time because the PORVs are smaller compared to St. Lucie 2.

Yeah. We'll do small-break LOCA. Small-break LOCA, we use the same methodology, what we currently have, and that is called small-break LOCA SM-2, SPM (ph) methodology, which was approved by the staff.

Only real change here is the tube plugging. The current analysis we have 30 percent; we ran to ten percent, and the other inputs here are related to the power, which we discussed earlier.

As seen on this slide, the PCT (ph) for the EPU is 1903, with Appendix K and all the other acceptance criteria are met.

MEMBER SCHULTZ: Jay, you've changed the steam generator tube plugging, and then you have PPU conditions, and the limiting break size doesn't change for the analyses? Where does this break size, where does it sit in the spectrum?

MR. KABADI: Yeah. I think the spectrum is run and Bob, why don't you --

MR. ATKINSON: Yeah. Limiting break size is a .05 square feet, and the next larger break size that was analyzed was at .06 square foot, and that had SITs injecting. So the zero-five was the break size, the largest break size within the spectrum for when SITs would not inject.

MR. KABADI: And then what we did, based on the staff's request for information, we did some sensitivity around that theme to show that PCT doesn't vary much around that.

MEMBER SCHULTZ: Okay, and the other, the other data that at least raises a question is that your maximum local oxidation has gone down. The maximum core-wide oxidation has increased limit and --

MR. KABADI: Yeah. I think --

MEMBER SCHULTZ: Have you looked at that to evaluate it?

MR. KABADI: Yes. I think we internally looked also on that. As you see here, one of the things to mention here, the reason PCT goes down is also because we were not taking credit for charging flow in the previous analysis on lower tech spec. Hence, charging is a part of ECCS. So we did take

credit for the charging flow, and that's why one of the reasons why the PCT is lower.

But as far as the oxidation, that's a part of the methodology, based on where you are rupturing and how you calculate. That's a conservative way of calculating the total oxidation and Doug, can you add --

MR. ATKINSON: That's correct. This is Doug Atkinson. Yes. The MACCS local oxidation follows with the PCT decreased. There is a change in the compression of the power. It's toward the center, and the integral effect of all the local oxidation values, you end up with a larger value for EPU.

MEMBER SCHULTZ: And then looking at core-wide oxidation?

CONSULTANT WALLIS: That goes up because of the flattening of the flux --

MR. KABADI: Correct, if you use -- yeah. That's where you calculate the flux, and again what we used was very bounding to that cycle, the cycle. We don't have to change anything, but meet the criteria.

CHAIR REMPE: So are there any additional questions? Brian?

CONSULTANT BONACA: I need to go back to page 24. I had a question about the CEA injection.

I just couldn't hear the conversation there, and the question that I had was how were these boundings calculated and how; that is, statistical results?

MR. KABADI: Any particular number?

CONSULTANT BONACA: Well --

MR. KABADI: Like CEA injection was specifically around -- the calculations are done for EPU from the neutronics point of view. Now in terms of DNB we just talking about, how it was done, but in terms of calories per gram, it was done following the approved methodology, which is currently Westinghouse methodology what we used.

CONSULTANT BONACA: Okay. So this was a 3D model that was used?

MR. KABADI: Kim can answer rather than --

MR. JONES: Kim Jones here, and that was a 1D BACTRAN model. They do a pin census or a 1D-2D FQ to come up with that.

CONSULTANT BONACA: Okay.

MR. KABADI: Yes. I think the current approved methodology has a 1D-2D synthesis, and that provides effects which are generally found to be actually more bounding than the 3D analysis. That's how the current analysis is done here.

CONSULTANT BONACA: Okay. All right,

thank you.

CHAIR REMPE: Are there any -- Charlie?

MEMBER BROWN: Yeah. I just wanted to get one follow-up on that that I forgot to ask on the SBO question. You talked about you've got two sites, you've got two diesels at each site. If one plant's affected, will the two diesels at the unaffected plant really be able to support both itself and the other plant? So the capacity is begin enough to do that. Okay. I didn't ask that. I just wanted to make sure. Thank you.

MR. HORTON: Todd Horton, FPL. Just a point of clarification. It is two diesel generators per unit, four per site, and on the loss off-site, all four emergency diesel generators would start. One thing that I think, maybe just to clarify, it is on the station blackout the operating crews are trained to immediately take action to start cross-tying power.

They don't wait until the batteries start reaching their four hour depletion period. It's immediate response for the operating crew.

MEMBER BROWN: Well, when I think "station" I think everybody loses, that both plants lose it at the same time. I'm just canoodling a way here, thinking well, what's the likelihood of being

able to get a couple of diesels back, because you are limited by that four hour period to get AC back before you start depleting your batteries in a bad manner.

So I'm not particularly happy with that. It's just a matter of where do you draw the line with your previous licensing condition.

MR. HORTON: Any one of the four diesels can provide adequate power for both units in station blackout.

MEMBER BROWN: Well, that means if they can recover it within the four hour period, at the no later than four hours.

MR. HORTON: Sure.

MEMBER BROWN: I just wanted to know what the --

MR. HORTON: The loads did go up slightly for EPU, some of the loads for the components, and that was evaluated.

MEMBER BROWN: Got it, okay.

MR. HORTON: And we have adequate diesel capacity.

CONSULTANT WALLIS: Let me just make sure that I heard it right. When you have SBO, it affects both units?

MEMBER BROWN: It's a common switchyard.

(Simultaneous speaking.)

CONSULTANT WALLIS: Well, someone said something about one unit. That's what worried me. But it is both units?

MR. HORTON: That's correct.

CONSULTANT WALLIS: Yeah, thank you.

CHAIR REMPE: Okay.

MR. HORTON: Todd Horton, FPL. Point of clarification. The loss of offsite power and the station blackout are two different events. The station blackout would be loss of offsite power coincident with the diesel generators not being available.

MEMBER BROWN: No, I understand. Yeah.

MEMBER SKILLMAN: I would like to ask Todd, when you have this event and the operators go to cross-tie all four engines, haven't you increased the vulnerability that a bus fault kills all four engines for both plants? Would it not be more prudent to keep the units separated until you know how the vulnerability is proceeding?

MR. HORTON: Actually, on a station blackout, we don't cross-tie all four engines. We identify a specific train of the unaffected unit and utilize its single diesel generator to supply power to

the affected unit. So let's say, for instance, Unit 1 is the unaffected unit. It has either one or two emergency diesel generators available.

We would not cross-tie those diesels and then supply Unit 2 with that power. You're right. It would make the condition vulnerable for some sort of event thereafter. So we do ensure that that's part of the emergency operating procedures, is we identify which train and which emergency diesel generator is best suited to supply the affected unit, so we can reduce those vulnerabilities.

MEMBER SKILLMAN: Thank you, Todd.

CHAIR REMPE: Okay. We need to take a break. But we've talked to the staff and we're a little ahead of schedule. But they're prepared to come back and do their open session part between break and lunch. If you have any of the requests, like the table that we've mentioned and other items that you can talk about too that's open session that we could do before lunch, that would be great, although we can accommodate it later.

But then we're hoping after lunch and do all the closed session information, okay? Okay. Break time. Let's come back in about 15 minutes, okay. So 10 til. How about 10 til, okay?

(Whereupon, a short recess was taken.)

CHAIR REMPE: Okay, Trace are you up, or is Sam or who's up first?

MR. ORF: Sam and Ben will present the safety analysis review.

Safety Analysis Review

MR. MIRANDA: Good morning. My name is Sam Miranda. I'm a technical reviewer in the Reactor Systems Branch, and I'll be presenting the long LOCA accident analyses evaluation of the St. Lucie Unit 2 EPU. This was performed by another technical reviewer in the Reactor Systems Branch, Summer Sun, but he's unable to be here today, so I'm filling in for him.

Ben Parks, sitting to my right, will talk about the LOCA analyses and the evaluation of those accidents. Just as an introduction, having been through the St. Lucie Unit 1 EPU evaluation, I thought that would be a good place to start. We have the two units, the one, one was licensed in 1976, the other in 1993, and they both came in for the same EPU power rating.

After the EPU is limited, they'll be rated at 3,020 megawatt thermal core power. The principle difference is that fuel supplier was AREVA for Unit 1, and Westinghouse for Unit 2, which means we were

looking at accident analysis supplied by AREVA and Westinghouse using their methods.

The Unit 2 fuel is CE-designed fuel fabricated by Westinghouse, and Westinghouse has used their analysis methodology for the EPU analyses. Both EPUs were audited by the Reactor Systems staff just about two weeks apart, January and February of this year.

Next slide. I selected a few events to look at in detail, because this is where we had some challenging issues, and it's the same with the EPU for St. Lucie 1. We had to look mass-addition events because these events are most likely to violate the anticipated operation recurrence/acceptance criteria and specifically the criterion that doesn't allow an Anticipated Operational Occurrence or AOO from escalating into a more serious event.

This typically happens when you pressurize the fills, and causes a PORV to open and discharge water. Well, since the PORVs are not qualified for water relief, we have to assume that any PORV that discharges water will remain open, and then this would create a small-break LOCA at the top of the pressurizer, which is an event of a more serious class, and it's a violation of the acceptance

criteria.

CONSULTANT WALLIS: But it can be closed. There's a block valve.

MR. MIRANDA: Yes.

CONSULTANT WALLIS: With most LOCAs, you don't have the valve.

MR. MIRANDA: That's right. It can be closed. In real life it can be closed, but in licensing, in the licensing world, the acceptance criterion has been violated. So that's what we need to follow when we do the evaluation.

This is what I described earlier. The charging pumps control the pressurizer. St. Lucie Unit 2, as St. Lucie Unit 1, has safety ejection pumps that are not capable of pumping against the nominal RCS pressure. But they do have charging pumps that are actuated by safety injection actuation signal. They're positive displacement pumps. They're small pumps about 49 GPM each.

St. Lucie 1 had three pumps. St. Lucie Unit 2 also has three pumps, but one of them is set to manual, so it's not actually actuated by the safety injection actuation signal. It's a small amount of flow, but it's sufficient to open the PORV, if allowed to go on long enough.

Next slide, please. This is the criterion that presents a lot of difficulty for Florida Power and Light and a lot of other licensees. The properly-designed plant would not allow a Condition 2 incident or an AOO from becoming a more serious event. If it's properly designed, there will be features that will present this, and typically this is demonstrated in accident analyses by showing that an AOO does not result in failing the pressurizer, and therefore it would not be possible for a PORV to open and discharge water.

Now the inadvertent opening of a PORV, this is a relatively new issue that's come up in the past three EPUs, and this was mentioned this morning by FP&L. The inadvertent opening of a PORV is classified a depressurization event or a decrease in RCS inventory. As a depressurization event occurring at full power, you do reduce thermal margin.

This event is analyzed to show that there is adequate protection provided in the automatic reactor protection system to prevent an occurrence of DNB. For a CE plant, we expect a trip would occur from the thermal margin low pressure trip logic, in time to prevent DNB from occurring. This event has been provided by the licensee, and has demonstrated

that DNB will not occur.

This event is analyzed typically for a short period of time until the reactor trip occurs, and after that, there's no danger of DNB. However, if we allow this event to continue after the trip. As the depressurization continues, it eventually causes the safety injection system to be actuated on pressurized or to low pressure, and once actuated, the ECCS is capable of filling the pressurizer, especially with an open PORV. It fills the pressurizer and could eventually pass water through the PORV, and now we have a situation where this Condition 2 event could become a Condition 3 event.

CONSULTANT WALLIS: It sounds like a recap of TMI to some extent.

MR. MIRANDA: Except -- well, in TMI, the PORV was supposed to open. It needed to open. The trouble is it didn't close.

CONSULTANT WALLIS: Well, it's the same effect, though.

MR. MIRANDA: Yeah, yeah.

CONSULTANT WALLIS: And then the pressurizer filling is the same sort of thing.

MR. MIRANDA: Well, the pressurizer -- no. Actually, in TMI the pressurizer didn't fill.

CONSULTANT WALLIS: The alarm wasn't in right, that's why.

MR. MIRANDA: It looked it filled. It looked like it filled, because of voids in the pressurizer. So the operators made a mistake and they thought they could turn off the safety injection with --

CONSULTANT WALLIS: They won't do that this time.

MR. MIRANDA: This time we have truly a fill to pressurizer.

CONSULTANT WALLIS: That's even more incentive to turn off the ECCS.

MR. MIRANDA: Yes, yes.

MEMBER SKILLMAN: Sam, I'm confused. TMI was an under-cooling event that led to an over-pressurization, that led to both a reactor trip and an opening of a PORV, and as you mentioned, the problem is the PORV did not close and the operators failed to diagnose that and didn't close the block valve, okay.

In this particular case, when I get the charging pumps running, I'm pushing up the pressurizer level, and if that continues, that level will threaten and push open a PORV, and they're not qualified for water. So I understand the logic.

MR. MIRANDA: Right, right.

MEMBER SKILLMAN: What is the first trip out? Do I go out on high pressure on the reactor cooling system?

MR. MIRANDA: You go out on low pressure. Well actually you go out -- you go out on low pressure. But before that, if the reactor protection system is properly designed, the first trip should be from a thermal low margin protection, and we verified that in the accident analyses. So the reactor trips at low thermal margin; later on, defense indepth, you get a low pressurizer pressure trip. It doesn't matter, because you've already tripped.

MEMBER SKILLMAN: I see, okay.

MR. MIRANDA: And then the continuing depressurization causes the SI.

MEMBER SKILLMAN: SI. Thank you, Sam.

MR. MIRANDA: Okay. We've seen from simulator tests that operators are trained to respond to this very quickly. They can close the PORV in less than ten seconds, and if the PORV doesn't close, there is also the block valve available. Again, this is the real world, and we have to, we need to consider this at --

CONSULTANT WALLIS: And what is the

operator's indication. Is it the temperature in the line from the PORV? Is that the indication that the PORV is open?

MR. MIRANDA: That's one indication.

CONSULTANT WALLIS: One, and there's also a signal supposedly that it's open?

MR. MIRANDA: Yeah. There's an indication that it's open. There's also, you can also check the pressurizer pressure and determine hey, at this pressure should a PORV be open or should it have been opened? Do you want to --

MR. HORTON: Yes. Todd Horton, FPL. I did appreciate the Subcommittee's discussion on the operator's response at the Unit 1 Subcommittee. One of the things that I had communicated at that time is this is one of the events that is a high priority for the operating crews to train on.

So I did go back to this station to identify exactly when was the next sequence of training that we were going to pull this performance training on the crews, and we did pull it back in cycles so I could complete that just prior to coming here. The idea was I could come here with detailed information.

So we validated. In fact, the operating

crews did identify the inadvertent opening the pilot operator relief valve in less than ten seconds. The things that help facilitate that is we have alarms specifically tied on the position indication of the PORV itself. Almost 99 percent of the alarms in the control room have a white background.

We have approximately a dozen that have a red. This is one of those alarms that has a red condition, so it immediately draws the attention of the operating crew. Another thing that draws the attention of the operating crew is we have acoustic monitoring downstream of the PORV. So when the PORV opens, the acoustic monitoring also goes to alarm.

The third thing that really facilitates the quick identification of the event is the reactor coolant system and pressurizer pressure are right there at the PORV. So the way the event unfolds is the red alarm enunciates; the acoustic monitoring alarms; the operator sees that and looks at reactor coolant system pressure, and validates that in fact that is not a real --

CONSULTANT WALLIS: But the pressure doesn't really respond instantly, does it?

MR. HORTON: I'm sorry?

CONSULTANT WALLIS: Does the pressure

respond instantly or it takes a while?

MR. HORTON: The pressure starts coming down and stops, but the operator validates that pressure is still in its normal operating band. They inform the unit supervisor. They take the PORV to override, and then we actually instilled a second fault is when you go to override, the PORV should have closed, as Sam mentioned.

The second fault that we instilled was okay, that didn't work. Then the second action is for the operator to manually close the motor-operated valve to isolate that penetration, and we validated all crews were doing that in less than 43 seconds.

The lowest pressure that we saw across the crews was 2,030 pounds. Normal operating pressure is 2,250. Safety injection is at 1,736 pounds, so we had quite a bit of margin.

So what we saw was manual action to isolate the PORV in less than ten; we mechanically isolated it in less than 45 seconds, and then we got below 2,000 pounds.

CHAIR REMPE: Was this standard the current in plant conditions and would you expect them to change if you dialed it up on the simulator to the EPU?

MR. HORTON: Actually, the simulator is modeled precisely with Unit 2.

CHAIR REMPE: The EPU though, or with the current?

MR. HORTON: The pressure post-EPU conditions will be the same, and there are no design modifications to the PORV.

MR. MIRANDA: So we have -- we looked at the licensee's analysis of this event, and basically we were interested in what would happen if the operator does nothing, and this slide indicates that if the operator fails to close that PORV, eventually the pressurizer will fill in very short time.

This is where we look at the difference between the real world. In the real world, the operator will close the PORV in less than ten seconds. But in the licensing world, we need to consider just how much time is available for the operator and what can reasonably be done following procedures and so forth.

So we pay attention to the time it takes for the pressurizer to fill, because that defines the time available.

(Off record comment.)

MR. MIRANDA: Okay. So to finish up on

that, the time that we're concerned with in this case is the time that the safety injection occurs, which will occur before the pressurizer fills. This is the time between the PORV opens and the time safety injection occurs. If the operator acts within that time, then and closes the PORV, the accident is over.

However, if the operator is a little bit late and safety injection is actuated, now we have an inadvertent SI actuation, a variation of that, and now the operator, in order to end the transient, has a lot more things to do to turn off the safety injection. It turns out that if the operator closes the PORV at any time after the safety injection has been actuated, that doesn't end the transient, but it does reduce it to a variety of inadvertent safety injection actuations, and it does gain more time for operator action.

In this case, operator action involves following procedures to turn off the safety injection, and that's going to take a lot more than ten seconds. So the staff is evaluating this event on a generic basis, and we expect to come up with a position because we expect to see more analyses like these.

This St. Lucie 2 is not unique. Pressurizer fill times of three and four minutes seem

to be pretty common. So we need to take a closer look at this.

MEMBER SKILLMAN: Sam, you used the words "inadvertent SI injection." Would it be accurate to communicate SI did what it was supposed to do at the pressure that it was supposed to do it?

MR. MIRANDA: Exactly.

MEMBER SKILLMAN: Thus reducing the time that the operators have to take any real significant action. Once SI starts, they have an inventory issue that they now have to deal with, a significantly greater inventory issue.

MR. MIRANDA: Once SI starts, and it does start. It's supposed to start. Once it starts, the operator has a real complicated situation. Simply closing the PORV will not end the transient, and that's going to take a lot more than ten seconds.

MEMBER SKILLMAN: My point is it is not an inadvertent actuation of SI. It is an appropriate action of SI for which there are consequences.

MR. MIRANDA: Right. That's why we asked for this analysis, because this is not, you know, a failure upon failure. This is what the system is supposed to do.

MEMBER SKILLMAN: Okay. Thank you, Sam.

CONSULTANT BONACA: I have a question for the licensee. Just for information, do you have one single simulator for both units?

MR. HORTON: Todd Horton, FPL. Yes, we do. One simulator for both units. It's primarily modeled for Unit 2.

CONSULTANT BONACA: But you do have setpoints different for Unit 1 and Unit 2. How do you manage that?

MR. HORTON: We do have some setpoints different between the units. As you mentioned, that is a key training piece with the operating crews that we focus on quite a bit. Now there are things that we perform in the simulator to enhance training in the simulator, to get operators familiar with changes on Unit 1.

Most notably is we've made some early modifications on the simulator in response to the Unit 1 EPU. But as you mentioned, when operating crews go into the simulator, it is modeled after Unit 1. So the setpoints are corrected for Unit 2. So when they go in there and they perform their training on specific events, they're Unit 2 events.

CONSULTANT BONACA: But is there any possibility of confusing the operators of Unit 1, for

example?

MR. HORTON: I think what the operating crews see that do license operators is the systems respond the same between the two units. Like for instance, the safety injection actuation signal on Unit 1 actuates at 1,600 pounds. On Unit 2, it actuates at 1,736 pounds. That is a unit difference between the two.

Now that is something that the operating crews discuss, they're trained to discuss during their briefs in those events. That is something we focus on quite a bit during our training. But the system still responds the same between the two units.

CONSULTANT BONACA: And one last question. Are the crews dedicated to a specific unit, or are they covering both units?

MR. HORTON: Their license allows them to operate on both units.

CONSULTANT WALLIS: You said this was a new event you're considering?

MR. MIRANDA: It's actually an old event. We're considering it a new way.

CONSULTANT WALLIS: Because it seems to me that it reminds me a lot of TMI. I mean you have a PORV open for some reason, right, and then if the

operator doesn't shut it, what happens? You've got various branches, depending on whether you turn off the safety injection or whether you close the block valve, and you've got different ways you can go and so on.

Now this seems to me an obvious thing to do 33 years. Say look at TMI, in say post-TMI action. What happens if a PORV opens and they don't show that? That's the obvious thing to do. We seem to be looking at it. So the half hour you desire you have now if this thing happened, and you're taking all that time to do something about it.

MR. MIRANDA: Well, it was considered. It was considered, but there's a small-break LOCA aspect, okay. A PORV open sticks open. It's considered as a -- well, it doesn't need to be a PORV. It could be a safety valve, some opening at the top of the pressurizer. But that's not considered as an AOO. That's considered in 15.6 as a small-break LOCA.

This particular event is considered in 15.2 as an AOO and is considered to be sure that we have DNB protection. But then recently we noticed well okay. We see that there's no problem with DNB. The reactor hasn't tripped. The AOO has been satisfied. But has it really, because if we continue

the event and we continue the depressurization, we'll eventually get safety injection.

That's going to -- in this case, it's not needed. It's going to be causing problems. One more point I'd like to make --

CONSULTANT WALLIS: I understand that. I'd just wonder why it takes 30 minutes to do this.

MR. MIRANDA: It's a good point. Yes. We just discovered this aspect of this event, yes. One thing that was mentioned earlier --

CONSULTANT WALLIS: Well maybe these are the events which are most likely, the ones you didn't think about until now.

MR. MIRANDA: We didn't think about it enough. It's always been in there.

MALE PARTICIPANT: You finished beating him up yet?

CONSULTANT WALLIS: You're still here, so you can do it.

MR. MIRANDA: We did notice, by the way, quite a big difference between the two units, St. Lucie 1 and St. Lucie 2, in terms of filling the pressurizer. Pressurizer fill time in St. Lucie 2 is much, much faster than St. Lucie 1, and the difference is that St. Lucie has much larger PORVs.

So we have a PORV with a capacity of something like 400,000 pounds per hour in St. Lucie Unit 2, filling the pressurizer in about three minutes; and St. Lucie Unit 1, with a PORV of about 153,000 pounds per hour, it takes about seven minutes.

We asked the licensee about this, and they, at our request, they performed another analysis of the St. Lucie 2 event, using the St. Lucie Unit 1 PORV capacity, and they reproduced the St. Lucie Unit 1 results. So that the cause is the PORV capacity.

MEMBER SKILLMAN: Sam, isn't there another piece of information that is important, and that is that the charging pumps were not originally part of ECCS, and in the course of time on this pair of plants, the charging pumps became part of ECCS?

MR. MIRANDA: We got a clarification on that at the last --

MR. D. BROWN: This is Dave Brown with Florida Power and Light. It has to do with taking credit for the charging pumps in the analysis. The charging pumps have always started at St. Lucie on a safety injection actuation, okay. The functional difference between the units is on Unit 1, three pumps start; on Unit 2, two pumps start. That's always been the actual true plant condition. It was whether we

were taking credit for them in accident analysis or not that's changed.

MEMBER SKILLMAN: I see, thank you.

MR. MIRANDA: And yes, this came up at the last EPU for St. Lucie 1, and my position on that is that was a mistake.

MEMBER SKILLMAN: An oversight.

MR. MIRANDA: They didn't include the charging pumps because they didn't want to take credit for the flow, okay. I would understand that if you're doing a LOCA analysis. But when you're doing an inadvertent ECCS analysis, you need to take credit for those pumps. They need to be in there, and they weren't.

As a result, the EPU application we received dismissed the inadvertent ECCS analysis, because as they were modeling the ECCS without the charging pumps, it wasn't necessary to do that analysis, since the safety injection pumps just didn't have a head to pump into the RCS at nominal pressure.

So we asked for the analysis, and we got the results. It's the same situation with St. Lucie 2. The ECCS does include the charging pumps. They are actuated by a safety injection signal, and therefore this type of analysis needs to be performed.

MEMBER SKILLMAN: Thank you.

CONSULTANT WALLIS: It's a very nice example of what is conservative from one aspect is not conservative from another, and you always have to be careful about that.

MR. MIRANDA: Yes, yes.

MEMBER SCHULTZ: Sam, let me make sure I understand. Then we heard the discussions from the licensee's viewpoint associated with the operator action and the simulator's response, the operator's response to the event on the simulator, and the timing of the operator's actions.

That would take care of the event, if there is operator action. All right, and you're saying then in addition, the staff is continuing to consider the event with respect to no operator action. But this is a generic issue that is being treated separately from this amendment request?

MR. MIRANDA: Yes, it is, and the concern I have when I look at this is that the shortening interval between closing the PORV or the block valve and the time safety injection occurs, because it's like a two-phase event. Once safety injection occurs, now it's more difficult to terminate the event. Closing the block valve is not enough; closing the

PORV is not enough.

So you see in some plant designs this pressurizer fill time is much shorter than what we're used to seeing.

CONSULTANT WALLIS: So what is the status of this? This is an ongoing, evolving issue?

MR. MIRANDA: Yeah. I've written a draft of a generic communication that it's being reviewed. We're trying to find the proper path for the bureaucracy to get this out.

CONSULTANT BONACA: I want to go back a moment to the issue of training, and having the same plant training, the operators on the behavior of two different plants, and I'm not saying there is anything wrong about it. I'm just saying that I would have liked to have had evaluation of the impact, potential impact on performance of this issue.

It just troubles me, I mean as I talk here, I'm thinking about so many different possibilities of confusion for the operators or whatever. I don't want to blow that out of proportion right now, but certainly I would like to have the Subcommittee considers a conversation today, at close of the meeting, for what you think about that.

CHAIR REMPE: So you would like us to

consider it in our comments, but there's nothing you would like to see from the licensee or the staff?

CONSULTANT BONACA: Yeah. I mean it may very well be that simply it was the surprise of not knowing that, that created this concern in my mind. There may not be a concern in the back of my mind. But I certainly would appreciate your thoughts.

MEMBER SKILLMAN: I would like to join the concern, but I would like to respond to Todd's comment. Dr. Rempe asked about the St. Lucie 2 simulator and underlying theme of Dr. Rempe's question was fidelity with regard to the current plant design, versus the upgraded plant design.

So in my very practical thinking, I say I've got a simulator. It's a four loop, Combustion, 2,700 megawatt plant, and I would think that the crews are doing just in time training and their normal training on that simulator for St. Lucie 2, as the plant is presently licensed and configured.

MR. HORTON: If I can speak, Todd Horton, FPL.

MEMBER SKILLMAN: Yeah. Let me go one more step further.

MR. HORTON: Okay.

MEMBER SKILLMAN: Or one step further.

The time's going to come, presuming the Subcommittee and the full Committee are in agreement, that you will have a 3,200 megawatt plant that's really at 3,050 thermal, including pumping. So back to Dr. Rempe's question.

For these simulator runs, were the simulator runs done with the higher power level and the higher core decay heat, or are these simulator runs, and we're talking about here today back in the 2,700 megawatt configuration?

MR. HORTON: The core model right now utilized in the simulator is the 2,700 megawatt thermal. To add a few talking points as to our discussion, the training piece is a huge piece of the EPU project. Obviously, addressing the operator needs and putting them in the best position possible, as we go through these EPU outages, has always been right at the forefront of implementing EPU.

Just in time training. Coming out of the last Unit 1 outage, even though we haven't gone to the higher power rate on Unit 1, a lot of the systems that support the EPU are in place. So we had very extensive just in time training for the operating crews as those systems came back to them, during coming out of the outage.

We did a very extensive evaluation of the simulator itself, to see which systems in the simulator did we need in place prior to implementing EPU. So things like the digital turbine control system that we talked about when you were here for Unit 1. We put that in place on the simulator, even though it wasn't in place on Unit 2, so the operating crews would really understand how that system works and responds on Unit 1 coming out of the outage.

One key piece that maybe we could discuss is the training program for the licensed operator, as we know, is an accredited training program. At St. Lucie, like a number of other stations, there are distinct differences between the units. That is something that is a key piece of the licensed operator's initial and continuing training.

We have shown high performance in those areas, but there's always gaps that we're always looking for and attempting to address. One of the things that's been a -- that was one of the things that the station put forward as a goal as we go through into EPU, is the goal is to not take the units farther apart, but to get the units closer together.

As I mentioned, functionally the systems to the operators, they appear almost identical. There

are a few distinct differences with the set points that we talk about, that we find ways to challenge the operators, to make sure they understand the differences between the units. But the way the systems respond and the way they look to them in a simulator is almost identical.

But as I said, the accredited training program takes that into account, and makes sure that those specific items we have definitely training requirements, to ensure that the operators understand the differences, what that means to them in the impact of operating the plant, and then we test them on a basis to make sure that they can demonstrate that.

MR. HALE: Yeah, and if I could, yes, our training program, our license operator training programs come under a lot of scrutiny from the NRC and INPO, and these guys can tell you what they go through to get that accreditation. It includes explaining how we accommodate and ensure that the operators understand the differences between the units.

Now with regards to the inadvertent opening of the PORV done at EPU versus the current power condition, it's very insensitive to power level, an overfill event. If we're looking at DNB like we typically look at this event, then yes, the decay heat

comes into play. But when you're really looking at it strictly from an overfill event, the power levels, the event's fairly insensitive in terms of fill time to power level, okay.

Really, we did that just to show, you know, how quickly we can confirm, because we didn't have that data the last time we were here for Unit 1, okay.

MR. HORTON: And just to add, as we've gone through this EPU process, one of the things that I am real pleased with, as I think most of us who are familiar know, that there's no tougher customer than an operator in a training program, and they've really challenged this site, to make sure that the EPU modifications are presented in a way that puts the operating crews' ability to be able to operate those systems, understand them and implement them, prior to actually them being in place and turned over to the operating crews.

CHAIR REMPE: With respect to Mario's question, is St. Lucie unique, that they have one simulator for two different units and training operators for both units, or is that standard across the commercial fleet? I just would like a --

MR. HORTON: We're not unique. I wouldn't

go as to say -- I wouldn't be able to speak to the standard, but I know we're not using --

MR. HORTON: It's common.

CHAIR REMPE: It's fairly common?

MR. HORTON: It's fairly common.

MR. JENSEN: Joe Jensen, Site Vice President. Having worked in the industry for 35 years and at various plants around the country, there's virtually no two unit facility where the plants are 100 percent identical. In virtually every case, there are deltas between the two units, and in virtually every case, they train on a single simulator.

I think the only exception I can think of probably is Beaver Valley, where they have two separate operating licenses, and so they have two simulators. But it is standard practice. We do delta training between the unit that is modeled on a simulator and the unit that is not.

We have to remember that there's a number of other training venues that we use to make sure our operators are well-trained. That includes our classroom training, that includes job performance measures where we physically take the operators into the plant on the operating unit, and they step through those activities that are necessary, in order to

respond to the various events. In addition to that, the on-shift training takes place in both units. So the operators are exposed and have to run through a number of reactivity manipulations and other events and activities on both units.

So the simulator, while important, isn't the only tool that we use to ensure that the operator are well-trained and can respond to those events.

CHAIR REMPE: Thank you.

CONSULTANT WALLIS: Now it seems to me that the Committee has to say something about this in its letter. It's not a trivial matter. Now the question is is it a matter of the EPU, or is it sort of a generic thing around the fleet? I'm not quite sure how you know whether it's a matter for the EPU, and we're told it's very insensitive to the power level. But until we see some numbers, we can't tell what that means.

MR. MIRANDA: I agree that it is insensitive. With respect to overfill, it's --

CONSULTANT WALLIS: Makes no difference to your arguments at all?

MR. MIRANDA: Not with overfill.

CONSULTANT WALLIS: Okay. So if some of that can be very clearly shown, then I think we're

okay. Otherwise, we have to figure out or maybe wait for what the staff position is going to be on how do you satisfy the regulations --

MEMBER BANERJEE: Well, I think there are two separate issues. This came up, of course, before.

CONSULTANT WALLIS: But this is a bigger PORV and all sorts of things.

MEMBER BANERJEE: So one issue is how does is it affected by the EPU. My understanding was that it's not greatly affecting the EPU, right.

MR. MIRANDA: I agree.

MEMBER BANERJEE: So the real issue is what should you do about it, and that's more of a generic issue.

(Simultaneous speaking.)

CONSULTANT WALLIS: --affecting EPU be quantified in some very discrete way?

MEMBER BANERJEE: Well, because of the times available yeah, you can -- I think -- have you got it quantified or not, Sam, in the -- how much the times are affected for various actions. It wasn't very much, if I remember, right?

MR. MIRANDA: We're talking about the period of time until reactor trip, which you know, might be ten seconds, and the difference in power

level would be, you know, 300 megawatts for a period of ten seconds, and then after that it's strictly mass-in and mass-out.

MEMBER BANERJEE: Right.

MR. MIRANDA: So I don't see a significant effect due to the EPU.

CONSULTANT WALLIS: So this mass is being heated, isn't it? It's not just mass-in/mass-out. It's also volume.

MR. MIRANDA: Well yes, yes of course. The SI water's coming in at about 70 degrees, and it goes up to 600 degrees.

CONSULTANT WALLIS: But a greater power level heats it and swells it up more, so that it rises more. So it's not just mass-in and mass-out.

MR. MIRANDA: Right.

CONSULTANT WALLIS: It's a response of the whole system.

MR. MIRANDA: Yes, yes. But if we're talking about differences, the differences is about -- is the period of time before the reactor trip occurs. The difference is the amount of the EPU, approximately ten seconds. We're talking about a fill time here that's on the order of three to seven minutes.

CONSULTANT WALLIS: So it's, how much does

it change, does the fill time change with the EPU? It goes from three minutes to something else?

MR. MIRANDA: Well, I haven't done that case.

CONSULTANT WALLIS: If it went from three minutes to two minutes, would that concern you?

MR. MIRANDA: I don't think we'd be even -- I don't think it would be even 30 seconds.

CONSULTANT WALLIS: Well, it would be useful to have some numbers there, I think.

CHAIR REMPE: One of the changes for the EPU are changes in the NSSS setpoints. Would any of those changes affect the timing for this event, or have you already implemented those changes into the simulator?

MR. HORTON: Todd Horton, FPL. The changes would not impact. I think what Sam and his group has looked at is from the time you get the safety injection signal and the ECCS pumps started at about 1,200 pounds, the high pressure safety injection pumps start injecting.

That's really your primary driver for filling the pressurizer. Nothing associated with those systems are going to change post-EPU. What's in place now will be in place then. Now one thing, just

to clarify, one of the things that we talked about was okay, well what's the differences between this and TMI?

It's kind of like I believe the point that was brought up, and I don't know if it was, you know, discussed enough, but one of the things that was mentioned is once you had the safety injection signal, it's not an inadvertent safety injection. It's a real safety injection. At that point, the ECCS pumps start and start injecting, as needed, as a result of the safety injection signal.

The operating crew wouldn't just immediately turn the pumps off. At that point, you would have a real safety injection. You'd enter the emergency operating procedures, and you've got very distinct actions to take, to validate proper inventory before taking manual control of those pumps. That's the difference between this condition and TMI.

MR. KABADI: Yeah, and this is Jay Kabadi, FPL. I just want to verify that the three-way timing which is presented, that is for EPU. That analysis done is the EPU analysis.

(Off record comment.)

MR. MIRANDA: We've seen from this analysis for St. Lucie 2 the important factors

determining the fill time. It is of course the rate of safety injection, and the rate of safety injection is largely determined by the depressurization rate or the back pressure the safety injection system is seeing. That is highly dependent upon the PORV capacities. We saw that in the difference between the St. Lucie Units 1 and 2, the difference in the PORV capacities.

So the EPU or power level in general has a very small effect on the pressurizer fill time. The power level is important in the beginning of the transient, when we're looking at DNB. Any more questions?

CONSULTANT WALLIS: Less than three minutes isn't very specific, is it? I think you need to be more specific, and say that there is at least three minutes for them to act, because less than three minutes could mean ten seconds.

MR. MIRANDA: That's right, and I think that yeah, that is not specific.

CONSULTANT WALLIS: That's not very reassuring as it stands.

MR. MIRANDA: It conveys our concern that this time is short.

CONSULTANT WALLIS: I think you need to

say the pressurizer fills in greater than something.

MR. KABADI: This is Jay Kabadi from FPL. FPL time in the analysis was 174 seconds.

CONSULTANT WALLIS: That's less than three minutes. I think you've got to show that there's enough time.

MR. MIRANDA: Well, we're not sure that there's enough time.

CONSULTANT WALLIS: Okay, you're not sure.

MR. MIRANDA: That's way, you know, it conveys our concern, and we have a very small time, less than three minutes. Less than four minutes would also be a concern. That's why we're looking at this generically.

MEMBER SCHULTZ: So in presenting the concern, it's approximately three minutes, which your concern is that's not a big number.

MEMBER BANERJEE: I think it's a generic. I mean it's not EPU-related. That's all we're saying.

MR. MIRANDA: Yeah. We need to take a closer look at it, because these times are getting shorter and shorter.

MEMBER BANERJEE: So what is -- I mean maybe this is not the venue to address this, but what do the staff plan to do about this? You're dealing

with this on several EPUs, right? So what are the plans?

MR. MIRANDA: I've written a generic communication. It's pointing out that this is an issue, and for certain plants.

MEMBER BANERJEE: Right.

MR. MIRANDA: Other plants it's not a concern, but it 's an issue for certain plants and as a regulator, I'm not going to tell people how they need to fix it, just that they need to pay attention to this and present to the NRC staff a credible rationale for dealing with this, something that will hold up to licensing standards.

MEMBER BANERJEE: So what is the state we are at right now? Have letters gone out to operators or licensees?

MR. MIRANDA: The stage we're at now is that I've written a draft of a communication, which it needs to be reviewed and issued, and we have written, I think so far, three safety evaluations, Turkey Point, St. Lucie Units 1 and 2 --

MEMBER BANERJEE: Right.

MR. MIRANDA: --where this is an issue, and we have come up with an argument as to why it's acceptable for the EPU, but we reserve the right to

revisit this on a generic basis.

MEMBER BANERJEE: Who is this draft letter with, your branch head or something right now?

MR. MIRANDA: No.

MEMBER BANERJEE: Where is the review process? What point is it at?

MR. MIRANDA: Well, at this point, I sent it to my branch chief for his review.

MEMBER BANERJEE: Now he's taken off for some --

MR. MIRANDA: Yeah. I don't think he's going to be reviewing it.

MEMBER BANERJEE: Right.

MR. MIRANDA: So I'm acting for him, so I guess I'm reviewing it.

(Laughter.)

CONSULTANT WALLIS: Would it help you if ACRS said something about this issue?

MEMBER BANERJEE: I mean all we can say at the moment is that we recognize this should be treated on a generic basis or something, right?

MR. MIRANDA: Yeah. Basically, where we are is we don't think this is a reason to hold up an EPU. We have written a safety evaluation that says it's -- well, at this point it's good enough, but we

want to look at it generically and come up with a better solution.

CONSULTANT WALLIS: It's an issue for not in EPU. It was an issue before EPU.

MR. MIRANDA: Yes, yes, that's right. I would say this is not --

MEMBER BANERJEE: EPU has very little to do with it.

MR. MIRANDA: That's right.

CONSULTANT WALLIS: The interesting thing will be to see how quickly the agency can respond.

MR. MIRANDA: So yeah. If you can raise the --

MEMBER BANERJEE: We've done this in some letters in the past, where we know that this is not a specific issue for this EPU, but we mention it in some generic sense, whether it be methods related to whatever, you know. We've done it. We've made comments on reactor physics codes, that sort of thing, in past letters.

However, with this aspect, if you've already got something underway and there's no issue with your going forward with it, then ACRS has not much of a role to play, I would think, you know. If you encounter resistance, that's a different matter.

This is the last EPU for a while.

MR. MIRANDA: Well we intend to continue with this, because it goes beyond EPUs.

MEMBER BANERJEE: Right. It goes well beyond, like the TCD issue. It goes beyond EPUs, right? So you're going to take some action on it.

MR. MIRANDA: Yes.

MR. PARKS: If I may in the interim, the staff's review activities consider this event even when it's not an EPU. I had a license action request on my desk a couple of months ago, and I know while we have to ask about this, the licensee showed that its safety margins were significantly reduced, and the staff's decision-making in that matter was following the licensee's awareness of the issue, appropriate.

The key message there being the staff considers this -- I was awfully vague. You know, we consider this --

MEMBER BANERJEE: That was a lot of legalese, Ben.

MR. PARKS: The staff's aware. We consider it in other things, not just EPUs, bottom line.

MEMBER SCHULTZ: And again, it goes to the importance of the operator actions as they are being

proposed and taken and demonstrated that they can be achieved, but then also the success of those operator actions, being effective.

MR. MIRANDA: And I think this is where Dr. Bonaca's comments come into play, because whatever solution is arrived at for this event, and also the inadvertent ECCS actuation. The protection against these events is not an automatic reactive protection system. It's in operator actions.

MEMBER SCHULTZ: Yes.

CONSULTANT WALLIS: This is where you might be reminded about TMI. I mean it was the operator actions that seemed to have led to the progression of the event the way it did.

MR. MIRANDA: Yes. They thought they were doing the right thing, but they weren't.

CONSULTANT WALLIS: Well, here they've got two things to balance. That's where they get in trouble. They do the right thing for one and then later on, you know, they fix the other one.

MR. MIRANDA: Yeah. They need to undo the automatic reactor protection system.

CONSULTANT WALLIS: It's not taboo to do that.

MR. MIRANDA: Not if you've followed all

the procedures.

MEMBER SKILLMAN: Let me make sure I've got this straight. What I think this, I think very valuable discussion has created in my mind is the recognition that the SI actuation of the charging pumps has always been part of this design, but the mass flow rate contributed by those pumps was not previously credited, and when it is credited, that mass volume has the capability to take an AOO to a small-break LOCA.

MR. MIRANDA: I would agree with that, yes.

MEMBER SKILLMAN: And that is an event that is entirely independent from the power uprate discussion. That is a basic design issue for this plant that we are talking about today, independent of what other plants it may be part of.

MR. MIRANDA: Yes.

MEMBER SKILLMAN: Thank you. I got it. Thank you.

MR. MIRANDA: Any more questions?

(No response.)

MR. MIRANDA: If we can move on to LOCA. Ben?

Large-Break LOCA Safety Analysis

MR. PARKS: I'm Ben Parks. I was not the reviewer for lost coolant accidents. That reviewer was Jennifer Gall. She is not able to be here today. She had long-standing prior obligations. So I'll present the results of her review.

I reviewed her safety evaluation and provided some feedback, so I am familiar with her review activities. This slide is the summary of the licensee's approach for ECCS evaluation. The licensee's methods for St. Lucie Unit 2 are based on and conformant to Appendix K of 10 C.F.R. Part 50. So the results are going to be quite a bit different, especially for the large-break loss of coolant accident analysis than they were for St. Lucie Unit 1.

Here's a list of the methods that the licensee used, and a note becomes important a little bit later in the presentation. The limiting PCT is calculated to occur during the late reflood. For the limiting large-break case, it's around 300 seconds.

MEMBER BANERJEE: So this is quite different?

MR. PARKS: Yes, yes sir.

MEMBER BANERJEE: Because of the methods.

MR. PARKS: In essence --

MEMBER BANERJEE: It's not due to the

plant.

MR. PARKS: That is correct. It's basically the most significant driver here, I think, or one of the most significant drivers is a very conservative decay heat model. For the next --

MEMBER SCHULTZ: Conservative, in that -- oh, there it is. 20 percent above, okay.

MR. PARKS: We use a 20 percent multiplier -- well, the staff doesn't use. The licensee uses a 20 percent multiplier and applies that to the ANS 1971 standard, as required by Appendix K.

CONSULTANT WALLIS: You mean 120 percent multiplier?

MR. PARKS: I apologize. Yes, I do. The licensee made the point in its application or in the first layer of RAI correspondence that thermal conductivity degradation is not important because our analysis methods are conservative, and it turns out there's a regulatory reason to make that argument.

When we promulgated the realistic rule in 1988, the Commission said, you know, significant public comment was made, as to whether Appendix K methods remain valid, and the Commission came back and said Appendix K is conservative, and so many features of its requirements are going to be retained, and

licensees may continue to use Appendix K.

The staff did, however, question a little bit deeper regarding the effect that TCD could have on this particular limiting transient. It was shown, through some sensitivity studies, that a substantial increase in fuel-stored energy would be required to drive blowdown peak higher than the reflood peak that we had seen in the results.

The reason that that study was done that way is because it's a system of codes that are used in various phases of the transient. So we ask for a sensitivity study on the first code. I believe CEFLASH is the blowdown code. We asked for the sensitivity studies in CEFLASH and we chose to leave alone the COMPERC results.

I believe that there is a 30 percent increase required in the stored energy, in order to get the blowdown peak to approach the reflood peak. It was quite a difference, and quite a bit of an increase in the stored energy.

CONSULTANT WALLIS: That's strange, to tweak the energy, because it's really the conductivity which matters.

MEMBER BANERJEE: Which is of course ultimately --

(Simultaneous speaking.)

CONSULTANT WALLIS: It also determines how quickly it comes out, doesn't it? So it's probably also, yeah.

MEMBER BANERJEE: But let me ask you this. This plant filled a lot of emergency core cooling available, right? So why, is it purely an artifact of the method, that you're getting a reflood peak rather than a blowdown peak? If you did a realistic calculation, you'd expect that you'd get a blowdown peak on this plant, right?

MR. PARKS: The best information I have available to me is obviously the St. Lucie Unit 1 results.

MEMBER BANERJEE: Right.

MR. PARKS: They have similar emergency core cooling systems and yes, I think if you applied more realistic assumptions, you would find that the limiting peak is either in the blowdown or in the early reflood.

MEMBER BANERJEE: Okay, yeah. So what is it about this methodology that is physically or not physically, because it's not a physical methodology, but why are you getting the reflood peak? What's happening there?

MR. PARKS: I believe in this case it's a difference in the decay heat modeling.

CONSULTANT WALLIS: Only the decay heat.

MR. PARKS: I can't say it's only the decay heat model. But I think that that's a significant driver.

CONSULTANT WALLIS: It's not that you're throwing away a lot of the available emergency water coming in --

MR. PARKS: Well yes. This method requires that the accumulator flow be largely bypassed.

MEMBER BANERJEE: right.

MR. PARKS: ECC bypass is a difficult thing to model, and I don't know that the realistic model is a whole lot more realistic with respect to ECC bypass. Those methods tend to throw a lot of cooling or yeah, accumulator cooling out the break also.

MEMBER BANERJEE: So it's not that which is causing the --

MR. PARKS: I can't say for certain. I truly don't know.

MR. KABADI: This is Jay Kabadi from Florida Power and Light. I think for the Appendix K

models, also there are very conservative, the transfer correlations used in the reflood phase. That's what drives the PCT during reflood much higher than what the realistic LOCAs would do.

MEMBER BANERJEE: Is this to do with the heat transfer to the dispersed, during the dispersed --

MR. KABADI: Yeah, I think that's correct. I think there requirements that once your flooding rate is below something, you cannot get ready for a lot of correlations that could be used in a best estimate test analysis.

MEMBER BANERJEE: So this is sort of an unusual result, because the reason we sort of fought the St. Lucie 1 situation and why we got such low PCTs compared to Turkey Point was due to the fact that it was dominated by the blowdown piece. I mean in Turkey Point if you recall, it was the reflood piece --

MR. PARKS: Early reflood, about 30 --

MEMBER BANERJEE: Oh maybe early, yeah. But whatever it was, the mechanisms was somewhat different, which is why you had a sort of 400 degree margin or maybe even larger in the best estimate calculations for St. Lucie compared to Turkey Point, which is much closer to the 2,200.

MR. PARKS: There were also some other fundamental design differences as well. I don't know, I'm not terribly familiar with the types of containment design, but the containment design any differences there could have been attributable to differences in the predicted PCTs and also the accumulators are much different.

MEMBER BANERJEE: Yes, of course.

MR. PARKS: At Turkey Point, they're a higher pressure.

MEMBER BANERJEE: Right, and that's more or less what we attributed. We were trying to make sense of why St. Lucie 1 came in so much lower than Turkey Point, you know, in the best estimate calculations. I think we rationalized that. Now we see a plant which is essentially identical in terms of this emergency cooling and so on to St. Lucie 1, coming in with a result which is showing, you know, completely different behavior due to the methods primarily.

So and we're trying to understand what it is about the methods which is causing this. So I can understand that the correlations that you're using are much more conservative. You're probably throwing away more water. I'm not sure of that. You're using a

much higher decay heat than a realistic calculation. Are there any other factors that we should be aware of?

MR. PARKS: I believe there's a difference in the accumulator pressure. I think that St. Lucie Unit 2 has higher accumulated pressure --

(Simultaneous speaking.)

MR. KABADI: This is Jay Kabadi of FPL. Yes. At St. Lucie 2, accumulator pressure is 500 psia and psig, which is much higher than St. Lucie 1.

MEMBER BANERJEE: What was St. Lucie 1?

MR. KABADI: St. Lucie 1 was originally 200 and they raised that to 230 as part of this EPU. One of the reasons the PCTs in Appendix K model that PCT in heat flux is so-called artificially driven so high, dictated by decay heat, that other changes will change that. That is like photo slide that was grid and stored and feed down to blowdown PCT, much, much higher than what this PCT was.

That still is below the reflood PCT because reflood PCT is calculated very high in the Appendix K model because of the decay heat and the correlations.

MR. PARKS: The other important piece of information that you might get, you kind of glean from

the ECCS research is the significance of these mechanism at a given phase in the transient. Decay heat's more significant. I think in the NRC's part, I think it's rated at about an eight in late reflood, and it's much less significant earlier.

The stored energy is rated very highly, and in early reflood it comes down to about a two, and then it's insignificant. So there's a combination of the way these phenomena are being treated analytically, and their significance at the given time in the transient.

MEMBER BANERJEE: Yes.

So it's an artifact of the calculational methodology here, and you can explain this. You've satisfied yourself, your colleague has.

MR. PARKS: I watched as my colleague satisfied herself.

MEMBER BANERJEE: Right, right, that you can explain this behavior.

MR. PARKS: In my opinion, I think that justified the staff's review approach here, where rather than sort of, for lack of a better word, require the licensee to do a complete reanalysis or explicitly address thermal conductivity degradation in this event, to ask instead that they do sensitivity

studies to show us what are we missing by leaving this out?

I think that that ties back. That's why I mentioned the rulemaking and the history there, because I think that that follows the Appendix K regulatory approach.

MEMBER BANERJEE: So you're saying you bumped up the stored energy by about 30 percent, and you still had the reflood peak?

MR. PARKS: That is correct. I think the results were, and I would have to confirm this, it increased the blowdown peak by about 250 degrees, and I have a picture of the limiting transient provided by the licensee. Do you have that slide?

MR. ORF: Is that part of this afternoon?

MR. PARKS: Yeah, probably this afternoon. I'm not sure.

MEMBER BANERJEE: If you like, you can defer this, yeah. You can defer the discussion.

(Simultaneous speaking.)

MR. PARKS: That's a closed session discussion, so let's don't go there.

MEMBER BANERJEE: Yeah. We can defer the discussion.

CHAIR REMPE: Yeah, and in fact --

MR. PARKS: Okay. Well, the slide was publicly available. It wasn't proprietary.

MEMBER BANERJEE: Okay.

CHAIR REMPE: Well, do you think you can go through the rest of this presentation in 15 minutes, or do you want take a break and come back after lunch?

MR. PARKS: I think I'll push it in 15 minutes or less. There's not much more information to provide.

CHAIR REMPE: Okay.

MR. PARKS: We don't have the slide. It shows a blowdown or a reflood peak.

MEMBER BANERJEE: Well, we can look at them later.

CHAIR REMPE: Let's see if we can finish, okay.

MEMBER BANERJEE: Yeah, later.

MR. PARKS: Okay. So this is the large-break LOCA. Let's see. There are a couple of other things the staff addressed. The staff asked some questions about downcomer boiling, the downcomer model for CEFLASH was pretty simple, and so the staff asked for some sensitivity studies to --

CONSULTANT WALLIS: SITs or the tanks or

the --

MR. PARKS: The accumulators.

CONSULTANT WALLIS: Accumulators, right. How does the downcomer get filled in a cold-like break? There's steam going up there, isn't there?

MR. PARKS: At some point, there's enough liquid, and I'm thinking through. I'm not working from memory, Dr. Wallis. It seems that you have to inject enough liquid that you get some sort of countercurrent flow limitation. You have enough heavy liquid that's not boiling.

CONSULTANT WALLIS: How does the steam get out then?

MR. PARKS: The steam is going to entrain the liquid from the safety injection tanks for a while. It's going to go out the break, as the break flow reduces and you have easier lower plenum steam conversion, lower plenum flashing, I suppose.

CONSULTANT WALLIS: The steam has to get to the break somehow, as in -- I'm not quite sure how the downcomer fills with water?

MEMBER BANERJEE: Eventually, the steam has to go the other way.

MR. KABADI: Yeah, this is Jay Kabadi.

MEMBER BANERJEE: It's got to come out

somehow, eventually.

MR. KABADI: Yeah, this is Jay Kabadi for Florida Power and Light. I think that Appendix K model, that's one of the things, that is one of the ways.

You go through the blowdown period, and that's why 900 water injector goes in other core. That's assumed to all go out. Once the pressure, that's the end of blowdown, where the pressure in the containment gets higher than the pressure in the RCS. That's when you want to start setting into --

CONSULTANT WALLIS: Well, it gets down there all right, but it doesn't fill downcome does it? I mean there's stuff steaming in the downcomer, isn't it?

MR. PARKS: Yeah.

CONSULTANT WALLIS: It can't get to the break without going through the downcomer, unless I've got it all mixed up.

MEMBER BANERJEE: No. I think it has to go down the downcomer.

CONSULTANT WALLIS: Well, there has to be counter-current flow. So there's no way the downcomer can be filled with water. I don't understand this rationale.

MR. PARKS: I see what you're saying. I think the staff may have characterized the phenomenology a bit out of order.

CONSULTANT WALLIS: Well maybe if you get to the full Committee, you can give a better explanation?

MR. PARKS: Absolutely.

MEMBER BANERJEE: Maybe filled is too strong a word?

CONSULTANT WALLIS: Yeah, it would be enough to suppress boiling somehow.

MR. KABADI: This is Jay Kabadi, FPL. Let me just -- I think what happens is once the pressure in RCS gets lower, the volume which goes through the loops, and that is what is balanced by the containment pressures. There is only the driving force coming from the containment side, and as the water gets in, whatever volume that goes inside the core gets through the loops and it goes through the loops.

CONSULTANT WALLIS: It doesn't go out the cold leg break, does it?

MR. KABADI: That is correct. Once the vessel --

CONSULTANT WALLIS: That's what's happened, that's what's happened.

MR. PARKS: Okay. So here are the EPU results and compared to the pre-EPU. During the staff's review, we considered the fact that the PCT decrease, we asked about that. In the license report, I think there is a very vague statement regarding credit, not fully crediting the improved features of the new steam generator.

The reviewer asked questions about that and then obtained sort of a rack-up list, if you will, of all the different changes they had made in their assumptions from the prior analysis to the current, to show what's the PCT effect of each bit and piece. Looked over that and they add up to this result. So the staff reviewed this difference.

MEMBER BANERJEE: What was the main reason that it decreased, which is so slightly strange?

MR. PARKS: I don't recall the exact rack-up. I intended to bring it with me and I don't have it.

MR. KABADI: Yeah. This is Jay Kabadi from Florida Power and Light. I think the back-up slides, the impact of the EPU by itself was in the range of 50, something in 50's, the temperature going up. Then the benefit came from the higher flow, which we increased in the reactor coolant system.

Their own analysis did use 335,000. We're using this one, 375,000, which is one of the changes we talked about, and the reduction in the peaking factor. The two together provide balance, and the actual number came out slightly lower in report.

MEMBER BANERJEE: But you've got a higher decay heat, right, and now your peak temperature is in the reflood peak, where decay heat matters. And, you know, the fact that you have a higher flow affects the stored energy, and you're saying the stored energy doesn't really matter as much as the decay heat. So I find that rationale pretty hard to understand. Do you follow what I'm saying?

MR. KABADI: Right, right. But I think the 54 degrees or so that came out strictly what they ventured about the EPU.

MEMBER BANERJEE: So the EPU gives you 10 percent or 12 percent or whatever more decay heat, right, than you had assumed?

MR. KABADI: Right, and that raised the PCT. That's correct.

MEMBER BANERJEE: That has to raise the PCT?

MR. KABADI: That is correct.

MEMBER BANERJEE: Because this is a

reflood peak, right?

MR. KABADI: Right.

MEMBER BANERJEE: And if you didn't change any methods between the pre-EPU and the EPU, you'd get an increase in that temperature. Now your higher flow --

CONSULTANT WALLIS: In some ways, he said he's injecting more water. I think he said he's injecting more water.

MEMBER BANERJEE: How is he injecting more water?

CONSULTANT WALLIS: Ask him.

MEMBER BANERJEE: Are you changing something else?

CHAIR REMPE: Radial peaking.

MEMBER BANERJEE: The peaking factor I can see has an effect.

MR. KABADI: Right. Yeah, I think a little like -- well, we've had some sensitivities on these, and those are the reasons what I presented, like you mentioned that why you mentioned like why are such slow decreases to PCT and that sort of thing. I'm just looking at the Westinghouse --

MEMBER BANERJEE: Well, increasing the RCS flow will reduce the stored energy, and but on the

other hand, you're also increasing the amount of power. So I mean the two things will sort of balance, to some extent. You know, I think we need a rationale for this, where you say the stored energy is affected by that much, by increasing the RCS flow, and the effect of the decay heat is this much.

So we understand. I'm sure that your colleague looked through this. It's a startling result.

MR. PARKS: It is, although this is fairly minor, I think it looks like about 25 degrees.

MEMBER BANERJEE: Yeah.

MR. PARKS: Fahrenheit. We'll look. Over lunch, we'll get the rack-up list. We'll have a look at it. You know, the original statement from the licensee was changes in the steam generator modeling, full credit, which implies that there be some primary to secondary heat transfer in play here. That makes sense for later in a greater stage of decay heat.

MEMBER BANERJEE: That makes more sense. That makes more sense because your decay heat is going up, and if you get the heat out through the steam generator, it makes more sense, okay.

MR. PARKS: So these are the results, and onto the small-break LOCA. We got a fairly coarse

break spectrum initially from the licensee, and the staff requested a more detailed one. I don't believe that the detailed break spectrum changed the limiting result. I think it was .05, or yes. .05 square feet was the limiting result.

The staff also requested and obtained an analysis of a severed injection line. The dynamics of the transient are a bit different, and it also affects how much ECCS you can get. On the next slide, we have --

MEMBER BANERJEE: What about the loop seal clearing? Did you ask for that as well?

MR. PARKS: I would have to check with the reviewer to see how it was addressed, and we can certainly do that.

MEMBER BANERJEE: Okay.

CHAIR REMPE: So we'll get answers to these questions today after lunch you think?

MR. KABADI: I think I have loop-seal clearing the -- at the approved methodology which we use for here, requires doing some sensitivities on the loop sealant, take the worst reasons.

MEMBER BANERJEE: And also making sure that ultimately only one of them clear, right?

MR. KABADI: We can check how many clear,

but there is some sensitivity in the different configurations, and the worst result is reported. So we can check and see how many cleared and --

MEMBER BANERJEE: Yeah. Just let me know what the worst cases are.

MR. KABADI: Right. We can check on that, yeah.

CONSULTANT WALLIS: St. Lucie 1 used a very complicated loop seal clearing model, which I didn't understand.

MEMBER BANERJEE: Well, it was a very, eventually a very conservative one, yeah. Nobody can understand it, but nobody knows anything about loop seal clearing.

CONSULTANT WALLIS: But they know that they can make a difference.

(Simultaneous speaking.)

MR. PARKS: These are the results for the small-break LOCA, and with that, we hope the presentation's concluded.

MEMBER BANERJEE: Again, you've got a lower peak clad temperature, with a higher decay heat. That's a remarkable result.

MR. PARKS: If the key driver is the same as for the large break, this transient has a large, a

boildown. It would make sense.

MEMBER BANERJEE: So if it's a steam generator, it does make some sense, yeah.

MALE PARTICIPANT: Yeah, I'd like to see that --

MR. KABADI: This is Jay Kabadi from FPL. Really, the main driver was a built-in credit for the charging flow. It was not written up by any model without getting early into transient health significantly. In the previous analyses under the CCS, charging flow pumps were part of the CCS. They have not credited charging pumps in this model.

CONSULTANT WALLIS: You're putting more water in, the same as large-break LOCA, I think.

MR. KABADI: Right. But the charging flow, again constant flow (mouth close to mic). Once the SI signal comes in, they start injecting into the small break, and that (mouth close to mic).

MEMBER BANERJEE: Okay. You have to rationalize it for us.

CHAIR REMPE: You want more then?

MEMBER BANERJEE: Yeah. We want to understand why.

CHAIR REMPE: Okay. So the staff will help address this today or the licensee?

MEMBER BANERJEE: Staff and the licensee together.

MR. PARKS: The staff will make its best attempt to provide clearest rationalization. Without the actual reviewer present, we may not be able to fully address the concerns. So I would say what we can't get done today we'll absolutely do early next week, when you're owed some materials, and definitely plan to talk about it at the full Committee meeting.

CHAIR REMPE: That sounds great.

MEMBER BANERJEE: When is the full Committee --

CHAIR REMPE: The week after the week of the 4th, like --

MR. PARKS: 10, 11, 12, 13.

CHAIR REMPE: Yeah.

CONSULTANT WALLIS: It seems to me when your staff member expert isn't here, then you need to anticipate the questions that we will ask, and get answers ahead of time.

MEMBER BANERJEE: He's just giving you a hot time, Ben. I apologize.

CHAIR REMPE: I know we all want to go to lunch and take a break, but there is a staff member who can answer Charlie's question, and so we're going

to get Charlie, and it will be a brief answer, and so if we'll just have that response, it will help. This is the anticipated outage time response; correct, is the question of Charlie's?

MR. BROADDUS: Actually, we were hoping he would be here to make sure he can clarify the question for the gentleman.

CHAIR REMPE: Okay. Charlie is in the other room, and Weidong is getting him, so just be patient.

MR. BROADDUS: Okay, thank you.

CHAIR REMPE: Okay. Your name is?

MR. MOSSMAN: I'm Tim Mossman. I work in the Instrumentation and Control Branch. Dr. Chung, who did the review of the measurement uncertain recapture on Unit 2 is unfortunately not here today. But I was his peer reviewer on his safety evaluation input, so I am familiar with the measure uncertainty recapture, and I will do my best to answer whatever questions.

CHAIR REMPE: Okay. I believe the question of interest is the allowable outage time, the daily FM, which may be beyond just this EPU. It may be something that the staff has agreed upon in prior reviews or --

MR. MOSSMAN: In fact, I just looked at the safety evaluation before coming over here.

CHAIR REMPE: And here he comes.

MR. MOSSMAN: Oh.

MEMBER BROWN: I thought you were doing this after lunch.

CHAIR REMPE: Well, the gentleman who's responding can't be here after lunch.

MEMBER BROWN: Well, that's a good answer.

CHAIR REMPE: Okay. So thank you.

MEMBER BROWN: Who's the gentleman responding?

MR. MOSSMAN: Tim Mossman.

MEMBER BROWN: Hi. I recognize you.

MR. MOSSMAN: Yeah. I've been here before.

MEMBER BROWN: Either good or bad, one of them.

MR. MOSSMAN: I was told the question was about the allowable outage time for the OEFM?

MEMBER BROWN: Yeah. I'm trying to recall what I said now.

CONSULTANT WALLIS: Two days, but no --

MEMBER BROWN: Oh yeah. No, I understand the two days. They had made a proposal on the AOT,

and the rationalization was that going for two days was based on the normalization they do every day at midnight or whatever the witching hour is, and therefore the ability of the thing to change over a two-day period of the alternate system was small.

There were some other words relative to that, in that they had evaluated and reviewed data to show that the change in that system was small. I'm forgetting the time frame, but it was a long, it was like 18 months of data they said. I don't know how many data sets of 18 months they took to say that yeah, that's a consistent set of data, and I'm not a statistics person.

So I had no idea how much data they used within that 18 month period to come to that conclusion. So I had two questions. Number one, did you all look at that, the data, how they came to the conclusion that it didn't change much. They claimed it was less than a .025 percent change over an 18 month period.

I just wanted to make sure somebody confirmed that their analysis of that data independently was .025 percent over that 18 month period. Did you all look at that?

MR. MOSSMAN: I would have to ask Dr.

Chung specifically what he looked at with that regard. But I know we've historically asked licensees. They generally, like you said, they generally hyper calibrate their venturis to the LEFM readings, and then they're using their venturi for that 48 hour or 72 hour period is generally what we've approved.

MEMBER BROWN: No. My concern was they keep recalibrating it all the time, and therefore how do you get 18 months' worth of data that says it doesn't change.

MR. MOSSMAN: I have seen other -- I've seen other licensees' values that they presented. In fact, we have one now, where they did the similar thing. They collected on multiple units for a year, ten-day drift times on all their transmitters associated with their venturis, and the number, I don't want to quote the exact number, they found is bounding, but it's very consistent with the .025 percent you quoted. It's a very small value on the transmitter drift.

MEMBER BROWN: Now but is that on transmitters, or is that the results of --

MR. MOSSMAN: It's the whole, yeah.

MEMBER BROWN: The results of the whole calculation, or just the flow information that's

going?

MR. MOSSMAN: It should be the signal coming from the venture. It's the air you're focused on.

MEMBER BROWN: So where does the normalization take place? Is that downstream or yeah, downstream where it all goes, so they can go get that data? They're not recali -- okay, let me go backwards.

I've got DP cells, all kinds of stuff on venturis. So you run a calibration, pop up little devices and you make sure that the readouts come out and the right voltages are where they're supposed to be, and they feed out to the converters, etcetera. Now when they normalize, they're not fiddling with that data?

MR. MOSSMAN: Not the raw feed.

MEMBER BROWN: Not the raw feed.

MR. MOSSMAN: My understanding --

MEMBER BROWN: Is that's the data that they take to make this determination, that the venturi and its detectors are not going to vary over 18 months? Which data are they using?

MR. MOSSMAN: Oh, for the 18 month data?

MEMBER BROWN: The output of the --

MR. MOSSMAN: Oh, yeah.

MEMBER BROWN: The output of the venturi downstream, you know, when it's coming out of lots of amplifiers and all the gain adjustments have been made and they're normalized or whatever they are, or is it the actual raw data off the venturi, or the RTDs themselves?

MR. MOSSMAN: I would have -- unless somebody from St. Lucie has that off the top of their head, I have to check on that. That was something that Dr. Chang looked at.

MEMBER BROWN: That was my question.

MR. MOSSMAN: Okay.

MEMBER BROWN: If you're taking normalized data every day, and you then do your 18 month review based on normalized information somewhere downstream, that doesn't seem to -- I'm not a statistician, and I'm not an analyst, but that doesn't seem to make sense to me, if they're taking the raw data over the --

MR. BROADDUS: Yeah, excuse me. Maybe this will help. This is Dave Brown from Florida Power and Light. When we talk about normalizing the venturis to the LEFM, that's not something that has occurred yet. We don't have an LEFM that's in service

that we're going through this process on. So what we did is we went and we looked at what was the venturis giving us over a period of time, to look at how acute is there a change or is it a chronic long-term effect that's occurring over a period of time, and use that fact that they're not changing as a justification for the time frame of being able to run with it at a steady state power level, with an LEFM out of service, and use the venturis as an accurate power indicator.

CONSULTANT WALLIS: How do you know if the venturis are changing if you don't have anything to compare them with? How do you know if the venturis are changing in the way they operate, if you have nothing to compare them with?

MEMBER BROWN: You do a calibration or -- when you took this 18 months' worth, how often do you recalibrate the venturis?

CONSULTANT WALLIS: How often?

MEMBER BROWN: Well, you've got a venturi --

MR. MOSSMAN: How often? I don't have that answer off the top of my head. That's an I&C activity, so I'd have to take, I'd have to look that up.

MEMBER BROWN: I guess --

CONSULTANT WALLIS: That's what I'm saying. How can you calibrate with nothing to calibrate them against?

MEMBER BROWN: At some point, you have to go, in order to get this data, you have to go check your calibration of your venturi instrumentation. The only way to do that is to go, you make two assumptions. Number one, the venturi itself doesn't change internally. That's kind of hard to do.

The second thing is to make sure your detectors, which are measuring the differential pressure across your venturis, those have not changed. In other words, your detector data hasn't changed, and you've got to figure out well gee, did the detector data change because the venturi changed? You can argue about that all you want to.

But in other words, how did you get the data, and who looked at it?

MR. MOSSMAN: I don't have an answer for what that frequency is, so I can't give you that answer.

MEMBER BROWN: That's kind of that question. Okay, that's one question. Okay, all right. The second question was nibbling, they gave you a multiple set of degradations. I think there

were three lines?

MR. MOSSMAN: They had two LEFMs installed --

MEMBER BROWN: Yeah, but one and then a couple of them and then something else, and I don't want to get into what they were. But they had three numbers, and you all came back and said umm gee, we think you ought to have -- those numbers ought not be as big as you're using. We want you to decrease power a little bit more, if I remember.

MR. MOSSMAN: It was -- yeah, and I took a quick look at this. It was very similar to one. We had, we first saw this, I think it was in Shearon Harris, where depending on the number of LEFMs installed, they constitute two different -- they have --

MEMBER BROWN: They've got two.

MR. MOSSMAN: Yeah, they have two, but each LEFM has two planes of detectors where they collect data from. Each LEFM, if one plane of detectors drops out of service for some reason, it can go into what they would now term a degraded mode for the LEFM check plus, which would be very analogous to the original system that they submitted and got approval for, which was the LEFM check.

MEMBER BROWN: And these were used?

(Simultaneous speaking.)

MEMBER BROWN: They said they haven't done --

MR. MOSSMAN: Yeah. If there was any checks, they would have been very early ones quite a number of years ago. The check plus represented an increase in accuracy, by adding additional detectors. But they actually had analysis and data that staff looked at in ER -- Norbert help me -- ER-80P, which was the original topical report on the one-plane system.

I believe for both Shearon Harris and I believe for St. Lucie, that Alden Labs, that did their specific testing of the LEFMs and the typing configurations that were supposed to go into the plant, looked at both fully functional and degraded modes, where you lose one plane of operation. So they do have reasonable data to make accuracy claims, as to how good the instrument is, if you do lose essentially your right or left hand of the instrument.

In this case, and in Shearon Harris, they had more than two. They had multiple, and we got an application that listed six or seven different degraded modes you could go into, depending on which

planes --.

As a branch we had significant discussions about how much credit you wanted to give somebody for degraded modes of operation like this, and the feeling was that given how highly reliable the instrument was, the odds of you getting into one of these kind of corner cases, where the right hand over here has failed, the left hand over here has failed, the left hand over here has failed, should be an extremely remote case for operation.

The value was probably not worth the additional complexity to their procedures, to grant that many tiers of operation. That being said, if I was the system engineer, I'd still ask for it, and I don't know specifically what Dr. Chung, if that was the same logic he used here.

But my guess is that was looking at the Shearon Harris precedent that we had approved previously, one tier of degradation, at the point in time where you have two systems degraded, that should be a fairly remote mode of operation.

MEMBER BROWN: Yeah, that's kind of what you did. You went from instead of having that third two megawatt list, you went full to the 2968 as soon as you hit the third category. So that was your

thought process, qualitative thought process in other words.

MR. MOSSMAN: Yeah, yeah. That it should, erring on the side of conservatism, at the point of time where you have both your instruments partially degraded in this case, it's probably a lot easier to operate and a lot safer, a lot more conservative to go back to your old power rate.

MEMBER BROWN: Okay. Now your SER states that "there are two CPUs. They are physically separate and redundant, each capable of processing all the data from both tool pieces."

MR. MOSSMAN: That sounds correct.

MEMBER BROWN: I'm just reading right from your SER, so I'm not making this up as I go here. I've been known to do that, so be careful. "The active CPU data source will be automatic for the DCS calorimetric calibrations, for where the analysis and all the algorithms are, "will be automatically swapped," swapped, swapped, S-W-A-P-P-E-D, "by the DCS when necessary, based on quality status flags of the LEFM and the Ethernet interface module between the two, LEFM and DCS."

Now if they automatically get swapped, does that automatically qualify as a degradation, and

is somebody going to move 3,020 megawatts down to 3,015? That just sounds like gee, if one loses-- if we can get something that says gee, that one's not working right. I'm going to swap to the other one.

MR. MOSSMAN: Yeah. I will --

MEMBER BROWN: Are there alarms that go off and somebody says now I have to run down and reduce my power by five megawatts? There's nothing that addresses --

MR. MOSSMAN: We typically get, yeah. I did not see it in the safety evaluation, but I know we typically do ask and we do get usually details as to what constitutes going into those degraded modes. I would have to check the original license amendment material to see what was described. I don't have that handy.

MEMBER BROWN: Well, I would, okay. So then my two questions, I guess it's still kind of hanging around, is how did they get this 18 months' worth of data, where did it come from?

MR. MOSSMAN: Okay.

MEMBER BROWN: Okay, which is how do you, you know, what did they compare it to? I presume it was within a prime standard alignment check of some sort, and how many data points did they have over the

18 month period, because you don't normally go in and pump these things up, take them out of service and pump it up and down every week. It's kind of a pain to do that.

Then the next would be okay, how do they know if these things were being swapped? Is that one -- every time something goes out, like you lose one section of the plane, does it automatically get swapped out and nobody has a choice? And then an alarm goes off and somebody knows that they're supposed to reduce power by five megawatts.

That's kind of the open questions, two open questions.

MR. MOSSMAN: Okay.

MEMBER BROWN: Now hopefully I'll be able to remember those for the next time.

MR. MOSSMAN: I will track those down ASAP.

MEMBER BROWN: Okay. Are you the one that's not going to be there afternoon?

MR. CARTE: No. I'm the one who's supposed to be here this afternoon. Norbert Carte. I think the underlining criteria for the swapping is whether you have one or two planes active, I mean for the degraded mode. So as long as you have two planes

of sensors active, you have heightened accuracy of the LEFM check plus system.

MEMBER BROWN: Full functionality.

MR. CARTE: Full functionality. So whatever failure causes you to have only one plane is when you degrade your level of acceptable power operations.

MEMBER BROWN: But does it also get swapped to the other CPU? How does somebody know that, and know it in time, in a timely manner?

MR. CARTE: Well, I think the typical case, I'm not sure about the swapping case. But the typical case is a sense failure. That's what typically causes you to lose a plane of operation. If you have redundancy views and they're swapping, I'm not sure about the answer. But the criteria is if you swap and you still have all your planes, then there's no problem.

MEMBER BROWN: How could you swap if it --

MR. CARTE: Well, if you have redundancy --

MEMBER BROWN: This says "quality status flags," which sounds like something's not operating right. So --

MR. CARTE: Right. So the processors --

I'm speculating, so I have to stop. But in essence, if you have redundant processors, that's their function, to detect when one is misoperating and switch to the other one.

MEMBER BROWN: I've tried to do that before with redundant processors, and it is very difficult to get it right, particularly if it's an automatic control system. We made it work, but it --

MEMBER BANERJEE: These aren't completely redundant either, because what they're doing, it's a very simple instrument. They have the speed of sound in this thing and they --

MEMBER BROWN: It's an ultrasonic flow detector.

MEMBER BANERJEE: So but they're sort of shooting across. But in order to get the velocity profile effects in, they shoot across at various locations. So even if you lose one of those sensors, it degrades your signal substantially. So you've got to do something about that.

MEMBER BROWN: You talked about angles in some of these also.

MEMBER BANERJEE: Yeah, there's also some -

(Simultaneous speaking.)

MEMBER BROWN: --from what I understand. But I don't want to get into the details --

MEMBER BANERJEE: So all you have to do is degrade one of those signals, and then that whole plane is not going to give you accurate results.

MEMBER BROWN: Okay. I guess two questions are still open, where did we get the data, okay, in order to verify that the venturi variations are small, or the detectors, whatever it is that causes it. Quite frankly the venturi, based on -- I actually took venturis and flow nozzles out of a plant after 25 years and found that their calibration in a calibrated facility varied so little we could barely measure it.

But that was 1975. So it was pretty good. The detectors on the other hand though, differential pressure. Those are different, and they will vary.

MEMBER BANERJEE: Well, the venturis tend to roughen slightly --

MEMBER BROWN: I understand, absolutely. Your nozzle coefficients and everything else will become slightly different. Anyway, those are the two questions. And then how do they know that they've go into the degraded mode?

MR. MOSSMAN: Yes.

MEMBER BROWN: It is an alarm that goes ringing because they swapped, or because something else. That's all.

MR. MOSSMAN: We typically have seen a fairly conservative approach to what constitutes degraded. So any kind of failure --

MEMBER BANERJEE: Did you consider any one sensor not operating properly as a failure of the whole plane?

MR. MOSSMAN: That's typically the way it's been interpreted, and as soon as one sensor in the plane, they fail the plane.

MEMBER BANERJEE: That's correct, good.

CHAIR REMPE: Okay. So we have one quick comment, and then I want to make a couple of comments.

MR. HOFFMAN: All right. This is Jack Hoffman, Florida Power and Light. Just one suggestion. We can make our lead I&C engineer available this afternoon. I know he is very familiar with the St. Lucie installation. Can answer all the questions he just had on factory acceptance testing today. We'll track him down and we can set up a time to get all these questions answered. He's the subject matter expert.

CHAIR REMPE: Great. That sounds great.

MEMBER BROWN: Will he have the how you get the data to say it's okay for 18 months?

MR. HOFFMAN: Knowing the individual, I would be shocked if he doesn't have it. He should. He is the subject matter expert that's been involved with this device since its conception.

MR. JENSEN: Well let's make sure he has the questions before we get him to the table.

MR. HOFFMAN: Of course.

CHAIR REMPE: And whatever we can't get this afternoon, we'll hit in the near week or so, we hope.

MR. HOFFMAN: We'll track down.

MEMBER BROWN: Yeah. I'll be in town. I live here.

CHAIR REMPE: We'll send it to everyone on disk or whatever, okay. So I'd like to close for lunch and restart at 1:30. Thanks.

(Whereupon, the above-entitled meeting went off the record at 12:31 p.m., and resumed at 1:36 p.m.)

CHAIR REMPE: Okay. At this point I'm going to reopen the meeting, and we're going to start off with some answers to questions from the licensee. And then we'll close the meeting, and proceed with the

scheduled sessions. Okay?

MR. HOFFMAN: Very good.

CHAIR REMPE: And we have an individual on the line. Will you state your name, please, and start answering -- are you aware of the questions, or do we have to repeat them?

MR. J. BROWN: No, I'm generally aware of the questions, and my name is Jeff Brown. I'm the I&C supervisor for the EPU project.

CHAIR REMPE: Okay. Go ahead and start answering the questions.

MR. J. BROWN: Okay. As I understand it, the first question pertains to the justification for the 48 hour AOT. Is that correct?

CHAIR REMPE: Yes.

MEMBER BROWN: Yes. In other words, how did you generate the data to determine that the venturi is stable -- or the data from that alternate system is stable for at least 48 hours, based on your 18 months of data collection? I just want to know what data you got, and what was the source of it, what were the devices, whatever.

MR. J. BROWN: Okay. So each venturi -- the two-headers, the venturi on each side is monitored by three Rosemont differential pressure transmitters

that develop the input signal directly into our DCS system. So what I did was, I looked at the last five calibration cycles, 18-month calibration frequencies on each of those transmitters, and looked at the drift that we'd see on each of those channels over an 18-month surveillance.

Typically with the Rosemont transmitters, they were within our quarter percent calculation tolerance, even with an 18-month frequency. So over a two-day period of time, 48 hours, the drift is very, very minimal.

In addition to that, the thing that could case significant drift would be a significant change in plant power, which could change the venturi fouling that is seen at that point in time. And under those circumstances, we have a requirement to down-power, enter the LCO.

MEMBER BROWN: Okay. Before you go any further, there's enough snaps, crackles and pops that I'm not sure I caught all of the data, 18-month data. You said something about five calibration cycles?

MR. J. BROWN: I reviewed data on over five calibration cycles.

MEMBER BROWN: And how long is a calibration -- is that the time between calibrations?

MR. J. BROWN: The calibration frequency is 18 months.

MEMBER BROWN: Okay. So once every 18 months, you recalibrate the detectors.

MR. J. BROWN: That's correct. Yes.

MEMBER BROWN: I'm writing. Okay. So you took five calibration cycles, or seven and a half years, worth of data.

MR. J. BROWN: That's correct. Yes.

MEMBER BROWN: So five data points, effectively, over seven and a half years.

MR. J. BROWN: On each channel.

MEMBER BROWN: Each -- a channel being one venturi's worth?

MR. J. BROWN: Right. So statistically, there's a lot more data than would be implied with a population of only five points.

MEMBER BROWN: I guess I'm not quite sure I understand that. A venturi -- this is not the LEFM. This is the old Rosemont detectors, and the venturi feeding them. Correct?

MR. D. BROWN: I think the key here is, there are three of these on each of the two venturis. So when you're collecting the data for an 18-month cycle, you're actually getting six data points over

five sampling periods, so a total of 30 data points.

MEMBER BROWN: Your math is too fast for my old brain. I've got three detectors per venturi, I've got that.

MR. D. BROWN: Well, I've got two headers, three detectors on each.

MEMBER BROWN: Okay.

MR. D. BROWN: And he sampled that five times, so we've really got 30 data points.

MEMBER BROWN: Fifteen times two, with two venturis. Right?

MR. D. BROWN: Correct.

MEMBER BROWN: Okay. I got that. So you're -- okay.

MR. HOFFMAN: And Jeff, this is Jack Hoffman with FPL. Just to clarify, for each one of those -- I don't want to put words in your mouth, but I believe I heard for each of those 30 data points, you were within the quarter percent?

MR. J. BROWN: I think what's accurate to say is that our general site experience with the Rosemont transmitters is that we very frequently find them within tolerance at an 18-month calibration frequency. And in this particular case, with these DP channels off the venturis, that was generally true

also.

MEMBER BROWN: What do you mean by generally?

MR. J. BROWN: I can't say that every single one of these 30 data points was found within tolerance, but a large majority were.

MEMBER BROWN: Well, what does that mean? How many were out of tolerance?

MR. J. BROWN: Well, and then for values that are found out, they are just slightly out. Generally speaking, the performance, drift-wise, on the Rosemont transmitters, is extremely good.

MEMBER BROWN: So how did you come up with 0.25 percent variation? You discounted the ones that were out of spec, or did you add them all up and average them, or did you take the boundary of the worst-case ones?

MR. J. BROWN: No, when we're looking at the transmitters being within spec at an 18-month frequency, we're saying that they're drifting a quarter-percent in 18 months. So over a two-day period, the drift is negligible.

MEMBER BROWN: Okay, but you also said some of them were outside the spec, also, though. The data says they were only a little bit outside. Does

that mean a little bit is a little bit? I'm being picky, but this is kind of a qualitative assessment, as opposed to a quantitative assessment.

MR. J. BROWN: They are found to be very slightly out of tolerance when they are out of tolerance.

CHAIR REMPE: So, can you put a number on it? Is it less than a percent?

MR. J. BROWN: It's certainly less than a percent. I's less than a half a percent.

CHAIR REMPE: Okay.

MR. HOFFMAN: Over 18 months.

CHAIR REMPE: Yes.

MEMBER BROWN: Okay. He's answered that question.

MR. HOFFMAN: Okay.

MEMBER BROWN: I'm not saying I agree or disagree. I'm just saying he answered the question.

MR. HOFFMAN: Sure. Jeff, I believe the next question revolves around out of service time, and the design features of the system, and what's required for the system to go from the nominal 3020 to the 3015, and then to the ultimate down-power scenario?

MEMBER BROWN: No, that's a table. You gave that table, and the NRC modified it. The table's

a table. I guess what I was interested in is, how does the operator know he's supposed to do something? When I read the -- see if I can find it again. When I read the LAR --

MR. D. BROWN: That's probably best illustrated by looking at the -- this is Dave Brown, FPL -- by looking at the diagram here, the simplified diagram, looking at the two feedwater lines coming up to the LEFM transmitter boxes off of each one, and then going to the two CPUs.

Now, there'd been a question earlier, and I want to make sure we address that, about the auto-swap. The auto-swap that was being discussed up there was actually an auto-swap between the two CPUs, so you'll have --

MEMBER BROWN: What does that mean?

MR. D. BROWN: Well, what it means is, you've got all the data coming from both LEFM, from all four boxes, that's going to both CPUs. If there's a problem with one of the CPUs or an input to one of the CPUs, it will swap and just use the data on the other CPU and give us an alarm to tell us that it has done that. Okay?

So it's not anything that has degraded the system. These are two 100 percent redundant systems,

both getting all the inputs. And you can see that by the multiple lines going into each one of those two boxes.

MEMBER BROWN: All four transmitters go to both boxes?

MR. D. BROWN: That's correct.

MEMBER BROWN: Where's the digital to analogue conversion done? Is that in the CPU inputs?

MR. J. BROWN: No, the D to A is in the transmitter boxes. I mean, A to D.

MEMBER BROWN: So it's a serial data stream that goes out to the CPUs?

MR. J. BROWN: That's correct. It's RS485 communication link between the transmitter boxes and the CPUs.

MR. D. BROWN: So if we lose any one of the four inputs going into the process, which is our first step of degradation, recognizing there's two on the Alpha leg and there's two on the Bravo leg, not only will that give me an alarm inside the DCS system, but that will give me a control room annunciator. The control room annunciator response procedure will drive me to the off-normal.

I start a 48-hour clock, and if at the end of 48 hours I have not gotten myself back into a four

out of four availability and operable, then I have to down-power by five megawatts.

MEMBER BROWN: So when it does a swap, it gets annunciated.

MR. D. BROWN: This is not a swap. Remember, all four of these are feeding into both CPUs, okay? So they're actually kind of separate issues. If one of these four is no longer good, when you come down here -- your two planes, you've got one, two, three, four --

MEMBER BROWN: You don't have to go that deep, I just --

MR. D. BROWN: Okay. Any one of these four fail, okay, then I get an alarm in the control room that says you're in what's called a check, instead of a check-plus, on one, and you're still in check-plus on the other. I start a 48-hour clock. At the end of 48 hours, if I have not got both of them into a check-plus, i.e. two, both redundant transmitters in service, then I reduce power by five megawatts.

Any loss of the system beyond that, whether it's one out of two here and one out of two here, or two out of two here, failures, goes to the full 48 hours reduce the two percent power, or the 1.7

percent, to get myself down inside the criteria.

MEMBER BROWN: What happens if one of the CPUs locks up? Like if you move the mouse, and your pointer doesn't move on your computer?

MR. D. BROWN: So the CPU is no longer processing?

MEMBER BROWN: Yes, if you no longer -- it locks up.

MR. D. BROWN: Jeff, do you want to speak to that?

MR. J. BROWN: Yes. Let me first of all say that each CPU has hard-wired outputs to the plant annunciator system, so the operators are notified of something wrong with the CPU independent of our communications to the DCS system. And then, within the DCS graphics that's used for the power metric, which we call our thermal power trend display, our analogue point is presented there for feedwater flow and temperature off of each header, those analogues out have built-in quality flags associated with them that drive color schemes, which are our human factors, to be consistent with the rest of DCS.

So the operators are notified in numerous ways of different failures in the system.

MEMBER BROWN: What's a quality flag?

MR. J. BROWN: Okay. So, out of each CPU, there are four possible quality statuses being transmitted to DCS. Four discrete values, zero through three. Zero means that the CPU is recognizing the LEFMs as completely normal. One means that there is a low level failure of some sort in the LEFM that doesn't reduce the accuracy of the system at all, but there's some minor maintenance item. Two would indicate that the LEFM is operating in a check mode. And three means that side LEFM is in a fail status.

So those quality flags, or the points that can take on those four discrete values, are also depicted on that calorimetric graphic.

MEMBER BROWN: Is that what swaps -- I still don't understand what the swap means, then. Swapped by the DCS.

MR. J. BROWN: Okay. Let me address that question by kind of presenting a failure mode to illustrate that. If I lose a transducer on one of the meters, what that would do is, within the Cameron system, because of the way they integrate the four measurement points in each plane worth of data, that would put that meter into a check mode. Effectively, the system is saying all of the data from that plane is no longer valid, so the system is then only using

the other four measurements of velocity of sound upstream and downstream to calculate a flow value. So a failure at that level of the system would be equally realized by both CPUs, and both CPUs would sense that and say "That meter, on that header, is operating in the check mode."

Now, if I had a different failure scenario, where I lost one of those RS485 communication links from an individual transmitter back through an individual CPU, then that type of failure would only be sensed by one CPU, the one that's affected by that comm link. So the other CPU would be a better source of data for DCS than the one with the failed RS485 comm link, and the system would automatically transfer over to that preferred source, then. And all of the data that's then being used, the flow and temperature data into the calorimetric, would remain completely valid, because it's being processed by the good CPU. And that is the automatic fail-over that you're talking about.

MEMBER BROWN: Okay.

CHAIR REMPE: Okay?

MEMBER BROWN: I didn't say it was okay, I said I'm done.

CHAIR REMPE: Okay. We're going to say,

then -- let's go to the other, real quick, presentation that goes with this response to the best estimate values. Thank you, Jeff. I think we're done with you from the phone.

MEMBER BROWN: Oh, yes. We're done for now.

MR. HOFFMAN: This is the best estimate.

CHAIR REMPE: Right.

MR. HOFFMAN: The question was asked earlier -- again, this is Jack Hoffman. And what we've passed out -- it was shared with Dr. Wallis earlier this morning -- is the actual calculation that Westinghouse performed to determine what the best estimate, or the way the plant is actually predicted to perform with the actual power level, no additional uncertainty or conservatism, actual flow. And what you have in front of you is a simplified output of that calculation for Unit 2 that has the actual expected megawatt for the plant, the 3020 megawatt in the core, plus the 14 additional megawatts of the reactor coolant pumps. You see our best estimate flow that was measured via RCS calorimetrics, and then you simply do the math in the computers, the thermodynamic math, to come up with the actual, what we can tell the operators that these are the numbers. That if they

have 551, if they program 551 T-cold, then they can expect to see an approximate -- I don't have the page in front of me, 602?

CHAIR REMPE: Point six.

MR. HOFFMAN: Which is a nominal number. It's not a bounding number that we would use in engineering analyses to ensure we have added conservatism.

CHAIR REMPE: Okay. With that, let's go on, if there aren't any questions, into the closed portion of this meeting. And we're unfortunately a little behind now, so let's all try and be mindful of the time a bit more, if it's possible.

(Whereupon, the above-entitled meeting went into closed session at 1:55 p.m., and resumed in open session at 5:52 p.m.)

CHAIR REMPE: Okay, is anyone still out there that's from the public that would like to make any comments? And just to verify, we do have an open phone line with someone out there that can verify that they're there. Maybe there's no one watching it. Is someone out there that can speak up and so we just know that there's someone out there?

Okay. Is there anyone left in the building that wants to make any comments?

Okay, I think we probably should go around the table, and this time I'll get someone to start with the consultants. And Mario, do you have some closing comments that you would like to share with us here?

CONSULTANT BONACA: I mean generally the application was well put together. I didn't see any issues except we expect that this to be an issue. And after you look at all the information, clearly there is a problem there, but the fortunate thing is that the results of the third assessment is coming close, and it may support the view that you have presented.

So I think you have a plan that you're using to monitor and assess and may be adequate in and of itself, but this is a big issue, of course, and I don't need to tell you that.

MR. GIL: It's really driven by the, you know, the operational assessment is obviously we want to get an understanding of what's going on with these generators, but it is driven by the data that we're seeing. So that is very important. If the data for the third inspection tells us differently --

CONSULTANT BONACA: Looking at a day that you may be able to go through a cycle maybe and, but you'll exceed 40 percent. But anyway that's

speculation.

Another issue I raised this morning was about the training simulator representing one plant or the other. I don't think it's a measure issue. I think it's more of an information issue for the Committee. I think that one way it could be handled is by the licensee presenting briefly what they do to the full committee as far as the documentation, just because information is important and you don't want to have people surprised as I was this morning.

So I think I have some other thoughts but I'll send it to you in a letter.

CHAIR REMPE: Okay.

Graham?

CONSULTANT WALLIS: Yes, I will send a letter too. I thought we were doing well until we got to the steam generator. It took a little while but most of the questions that we had eventually got answered and the new evidence that was behind the claims emerged. So I felt pretty good until I got to the steam generator.

Steam generator, I think is a significant issue. I agree with Sanjoy that we need, you almost need a whole day to look at the issue by itself and what the evidence is and then you need to weigh it,

instead of is it really appropriate to move ahead with an EPU when there are some uncertainties about this wear? Root cause analysis is all very well but it's a very unusual event, and so you don't just accept the first root cause analysis, you see, without a lot of thorough investigation of it. So I would think that you need to have another meeting on the steam generator issues before you go to the full committee with the EPU.

CHAIR REMPE: That's a valid point.

Charlie?

MEMBER BROWN: First of all, they answered all my questions satisfactorily from your earlier part so you can put those aside relative to concerns in anything to deal with otherwise.

I'm not a thermal hydraulics guy as is Sanjoy and some of these other learned individuals, but I'm going to give you my thoughts unabashed from what I would call a pedestrian electrical engineer guy that has dealt with plants for a long, long time and also listened to the steam generator guys in my program for a long, long time, vibrations.

Number one, all the initial analyses -- and I'm just going to say what I got out of the presentations and the discussions which were pretty

extensive. None of the initial analyses predicted anything of what you observed in the initial round. You made that statement. And not only did they not predict it, the indications were extensively more than expected, almost in the zero or close to zero you would have expected.

The wear after the second cycle was less but it was still a lot. You did your root cause analysis and assessed the issue as a nonuniform or nonhomogeneous, whatever the proper terminology is, gap and with between the tubes and the tubes support antivibration bars. There was some, I guess, modifications to the analysis. I'm not quite sure of all the details -- don't ask me -- where you said, oh okay, now we've taken this into consideration and looked at this nonuniformity and we can now predict that to some, what we saw and kind of duplicated the pattern or the distribution somewhat.

And therefore the conclusion is that based on our ability to take that modification, we can then take it and apply that to the EPU conditions and come to the conclusion that our wear rates will be within the boundaries which are deemed acceptable in the design and operational world. That's an extrapolation though without basis of any empirical results.

And if you had only had a few indications I would have maybe come to a different conclusion, but because of the thousands of indications, I guess I wouldn't really be convinced that it would be okay to go to the EPU conditions. And if these gentlemen can convince me of that, that would be fine. Okay. Without completing, number one, the third inspection to see how far it's come, that's under the pre-EPU conditions, and then if a decision is made to go on and allow the EPU to proceed, I don't think I would agree with at least today that it would be okay to go for a full 18 months or whatever, two-year, I don't know what you all's refueling cycle is.

MR. HALE: Eighteen.

MEMBER BROWN: Okay. Without another inspection or two mid-cycle or at third cycles, whatever it is, no matter how aggravating those are, where you could now take your EPU condition analyses and predict what additional wear you should possibly see and then see what you get in either a mid-cycle and end-of-cycle inspection or some other combination in between, as onerous as that sounds, so that's a path forward relative to the technical aspects.

The other, being a non-steam generator guy, it blows my mind that the number of indications

were thousands on the first cycle. That just seems to be out of bounds for the most part. I have a hard time coming to grips with why that is okay under any circumstances.

And I find it difficult from a qualitative standpoint to think it's okay to kind of wear myself into acceptable additional later wear rates as we continue to operate.

Now, it may be okay. It's just when you look at, you know, the numbers that you were given and the fact that you had to go and that's a qualitative, strictly visceral, qualitative look at what you presented.

I thought you did a good job of presenting the information you had and you were straightforward and open about it. I thought that was very, very useful and that that's kind of the way my non-initiate thought process goes on this.

Again, I would be open. Now, there's other folks sit here and pound me into submission. There's an outside chance that I might agree.

MR. GIL: No, I appreciate the input because that gives us the things that we think we need to --

MEMBER BROWN: And I tend to agree, that

I don't think a full committee meeting in July is going to be very useful. You'll have an hour and a half or two hours. You can do it and make an initial presentation. I think that's been done before where there was a full committee meeting.

I'm thinking process right now, and you're familiar with one of them, where you got through what I would call 95 percent of the things and you came back with the last 5 percent at a second meeting and that may be an acceptable approach.

I don't have any problem with that, but it ought to be understood what the basis is and we ought not get wrapped around the axle on this issue because this issue could take up the entire meeting or a whole morning alone.

So you wouldn't be able to get through the rest of the things. That's my concern to you, Joy, when you make your recommendation so, anyway, I'll stop there.

CHAIR REMPE: Okay, thank you. Dick, I want to ask for your comments but also I know there were a lot of issues you had.

There are some requests for things we've asked for, but let us know if there's any outstanding issues and other things besides this last issue coming

up a lot with various members.

MEMBER SKILLMAN: At this point no additional issues.

CHAIR REMPE: Good, okay.

MEMBER SKILLMAN: But let me make my comments. I would like to thank the FPL team and the NRC staff for a very comprehensive presentation. This has not been easy and you stayed on the watch and thank you for doing that.

I concur with Dr. Wallis and Dr. Banerjee. I think we need more information on the steam generator phenomenon and that's how I would like to describe it.

It seems to me that there is an additional mechanism or phenomenon at work that's beyond the secondary side flow energy, beyond rarefaction, beyond vibration and manufacturing. It seems to me that there is another issue that we haven't discovered.

And I think it's been easy to point to the thermal hydraulics when there may be another very reasonable explanation for why this wear is occurring and I would like that to be explored.

With regard to the small-break LOCA and the large-break LOCA, I recognize that what FPL has done is taken credit for built-in conservatisms in the

basic plant design and in your tech specs.

But I believe that when one looks at the EPU peak clad temperature for large-break LOCA and the EPU analysis peak clad for small-break LOCA and learns that they are, in fact, lower in absolute value than the pre-EPU values and the oxidation is also lower, that that is counterintuitive.

One would say more heat, more decay heat generation rate, those numbers should have gone up. Why did they go down?

I believe that needs a more thorough explanation, perhaps as simple as a table that shows the increments that were used to end up with a final result under EPU conditions that are, in fact, cooler fuel, lower temperatures and less oxidation. So those are my comments and I thank you for letting me speak.

CHAIR REMPE: Actually what I wish I'd done before I started our comments was ask the staff in light of what they've heard about all the steam generator discussion today if they have any last-minute comment that they wanted to say.

MR. ORF: I don't have anything.

MALE PARTICIPANT: Use your mic.

MR. ORF: Oh, I'm sorry.

CHAIR REMPE: You can come up here.

MR. ORF: This is Trace Orf. I don't have any additional comments but we do have other --

(Off microphone discussion)

MR. ORF: No. I guess none of our reviewers have any other comments as well.

CHAIR REMPE: Okay. I have a process question too for you. With this August inspection, the staff should be involved in any decision with respect to the data too and that is part of the plan which I hadn't seen discussed anywhere, right?

MR. ORF: Typically whenever these inspections are done we have steam generator experts on the staff who do --

CHAIR REMPE: Because, see, but there could be some midway data where you see something may be close but a bit more and would you still go forward with the EPU? I mean, you know, the cart's before the horse is, I guess, an issue that I think I'm wondering about.

You know, it may not continue to go down. What if it stays level? Would you still say that's the one with the EPU? I mean, there's some midway kind of data that might come out of it and I'm just kind of wondering how that data would be treated too.

MR. GIL: We will, but it really is at the

request of the staff. We'll have conference calls. Especially if we have something that's out of the ordinary, we'll have conference calls with the staff and go over with them what the results are. And we wouldn't want to do that before the end of the outage where they can determine whether --

CHAIR REMPE: A question I had for you too is that if you were to come in July and you see the whole committee behave similarly to the subcommittee in their comments, and they say we'd like you to come back, we don't have a full committee meeting in August so we're talking September and so that's something that might want to influence your decision too but --

MR. HALE: Steve Hale, Florida Power & Light. What we found is, you know, if we can be successful at subcommittee, you know, our biggest issue is that we're shutting down in August and we're going to be implementing all our EPU modifications.

But if we feel comfortable getting through subcommittee, you know, we'll proceed with all those modifications and implementation, that sort of thing, so, you know, we kind of figured that would be a potential.

So a September full committee meeting I think would work for us but, you know, I guess we

would be looking for a subcommittee in July, maybe just focused on steam generators I guess. Would that be --

CHAIR REMPE: Well, you won't have data by July.

MR. HALE: Right.

CHAIR REMPE: And so you may not get what you want is what I'm kind of saying.

MEMBER BROWN: There are subcommittee meetings in August.

CHAIR REMPE: There are subcommittee meetings in August but, again, is it worth even going to full committee to present some information because if I were a betting person I'd say you're going to have some issues with the steam generators and --

MR. HALE: I need to bring out something. First off, the inspection, steam generator inspection was never tied to the EPU. The one that we're doing in August.

CHAIR REMPE: Right.

MR. HALE: Okay. Not that it can't be, but the current plan going forward was that would just be a follow-up inspection. We'd factor it into the operational assessment and that sort of thing.

You know, that's certainly something we

could say, hey, we would not go to EPU until we complete or we make a license condition. We wouldn't go to EPU until we confirm the data from that inspection.

In the absence of data, I've heard a couple of folks mention a possible mid-cycle outage as a potential way to resolve it.

CHAIR REMPE: Yes, and that would be a way to resolve it.

MR. HALE: Certainly we would have to go back and discuss that internally, but I guess my question would be would that be an alternative to resolving this issue with full committee?

CHAIR REMPE: I can't answer for the full committee but I think that's a way that it seems reasonable to go ahead and go forward with the full committee meeting, that you would get a letter.

And, again, if you were to offer up the mid-cycle inspection in full committee, I bet things would go easier but that's up to you guys. But then I would say, well, let's go ahead and go forward with the meeting as we planned.

Otherwise I think things could really, but, you know, it's worth going ahead. It sounds like you realize the risks and we'll see you in July.

MR. HALE: Terry, would you like to weigh in at all on it?

MR. JONES: Terry Jones, FPL. First and foremost we want to make sure that, you know, we're nuclear safe and I think there's been a mischaracterization that there's not data. There is lots of data.

So maybe our approach here was when we decided to present our conclusions, maybe we'd been better off starting with here's the root cause of why we have indications in the steam generators and here's what we know and here's what we understand and here's where we are and here's what supported our data.

So it doesn't look like we got all the data on the table in the time to thoroughly, you know, vet that data as an observer watching this proceeding.

So what I'm very much concerned about from my perspective and my role in this is I'm happy to be the guy in charge of all the EPUs, Point Beach, Turkey Point, and St. Lucie, that is. I happen to know we have thousands of people on site and what we have invested up to this point.

And so I also, having been in this business for 30 years, based on the data that I've been presented with and involved in the root cause, I

don't have any nuclear safety concerns. We obviously did not successfully address those here so I understand your position.

I'd like to be able to have an opportunity to present and get the data on the table and get it thoroughly vetted and reviewed. We had a hard time getting to what the actual root cause was here today.

So at the same time, given what we have at risk as a company, I can't go into an outage, not at least having been through a successful ACRS, whether it be subcommittee or full committee.

And so like having a subcommittee some time in August for us would kill the project, just that's the logistics that we have. So if we can get, whether it be full committee or some sort of subcommittee review dedicated to the steam generators so that everybody could be satisfied, that would be good.

License conditions are good too. The scientific methods that everybody in the world uses to know if it's safe to operate their steam generators from one cycle to the next, whether they have one indication or a thousand indications, is the same in a well-vetted and proven process.

And so whether it be a mid-cycle

inspection or a license condition that says if our data is not borne out on the third inspection no review. We certainly would entertain those kind of things.

So I would respectfully request that we look for when we can come back and, you know, thoroughly vet the root cause and the data that backs up the root cause including the data from our two inspections.

MEMBER BROWN: So you would want that in July then? You said August was kind of a non-starter. I'm just trying to make sure I understood your comment.

MR. JONES: Yes, the reactor runs out of fuel August the 5th and so there's, you know --

CHAIR REMPE: Well, you can always refuel and continue going on the way you are, right?

MR. JONES: Not without hundreds of millions of dollars of impact on the company.

CHAIR REMPE: I know. I'm guessing what we should probably do is go ahead and have the full committee meeting in July and there'll be less time. You're not going to go through all the steam generator information obviously then.

I'm not sure. I don't make the decisions

on the scheduling for the next subcommittee meeting but, you know, what you will probably end up with will be what you end up with with the full committee and, you know, we'll just have to see what happens but --

MR. JONES: Well, for one of our other plants, we came back to a subcommittee.

CHAIR REMPE: Yes, I know we did that with Turkey Point with thermal conductivity degradation and --

MR. JONES: Right, with the thermal conductivity there was no way that anyone had enough time to vet that and so none of us were comfortable going forward.

And so we came back to a full committee in September even though I'm in the outage and even though I've chopped up the plant, to put it quite bluntly, and there's no way to restart, you know, without that approval.

If we're through a successful subcommittee -- that's what we did with Turkey Point. We got through subcommittee. The full committee didn't occur until we were already in the outage. Same was the case for Point Beach.

I think it's undue pressure, unreasonable and if the full committee needs to happen at a

different date in September that still gives us adequate time on the back end to receive the LAR in time to start the unit up.

I just think that, you know, if an all-day subcommittee is what's right and appropriate for the steam generator, I just would respectfully request that we be given an opportunity to do that in July.

(Off microphone discussion)

CHAIR REMPE: In light of the discussion, do you want to come to the full committee in July?

MR. HALE: Well, I think the problem with that is that you have such limited time, you know?

CHAIR REMPE: Absolutely.

MR. HALE: And, you know, I feel, based on, you know, the feedback here, we probably need to vet out some of the details of what we found, you know, in terms of inspection data similar to what Terry has said, you know, because we did go to full committee at Turkey Point and, you know --

CHAIR REMPE: Yes, it's going to be more money for you, more trips and everything.

MR. HALE: Right, and it quickly, you know, it was obvious that we needed to go back to subcommittee. I know that Sanjoy was really interested in it. We might want to make sure that we

resolve his concerns as well.

And I think it would be worthwhile if, indeed, I mean, we need to go back and we need to look at what other options there may be there and I think that we would like to discuss those options with the subcommittee as well so that when you do go to the full committee we have a direction.

CHAIR REMPE: That would be a better approach.

MR. HALE: Yes.

CHAIR REMPE: Where did Tanny go?

MR. WANG: Tanny went to check for the schedule I believe.

CHAIR REMPE: Okay.

MEMBER BROWN: Something's going to have to be moved probably so --

CHAIR REMPE: July, I'm guessing is going to be tough because of the schedule. August, I know there's a Monday that actually is available but that's subcommittee in August and then you'd be at September before --

MEMBER BROWN: Full committee week in July is locked up Monday through Friday but the second round, if my memory serves me right, is thinner on the second week.

CHAIR REMPE: It is except that I have another commitment and I don't know about other folks.

MEMBER BROWN: Outrageous.

CHAIR REMPE: And so I can't come in until the naval reactors thing on the Wednesday.

MEMBER SKILLMAN: We've got naval reactors and that --

MEMBER BROWN: Yes, well, that's what I'm saying. That week it's naval reactors and then if you look at the other, there's another meeting.

CHAIR REMPE: I think APWR is later in the week, isn't that what it is?

MEMBER BROWN: It's APWR, yes.

CHAIR REMPE: I think that's what it was.

MEMBER SKILLMAN: In August we're into Recommendation 1 in Fukushima again.

MEMBER BROWN: That's at the end of August though, isn't it?

MR. HALE: Couldn't we replace the full -- well, I guess that wouldn't work either.

MR. JONES: Maybe one of the options is to package the information appropriately, distribute the information early next week and stick with the full committee since that date's already there.

And if all we get through is steam

generator, then all we get through is steam generator but at least we know what the September full committee would be like.

CHAIR REMPE: Generally speaking, there doesn't seem to be many issues other than the steam generator issue.

MR. HALE: I think we've answered all the questions. I know Bonaca wanted us to talk a little bit about training.

CHAIR REMPE: I think it actually would be --

MR. JONES: That may be the best plan, is for us just to take the feedback here, put a package together, distribute it next week to the members of the full committee and let's start with that issue on the full committee on July the 11th.

CHAIR REMPE: Yes, I actually do and then keep in mind, please, that you won't have data for EPU and so, frankly, offering up a mid-cycle inspection might be a way that you could actually even have a letter from the full committee in July.

MEMBER BROWN: That's why I brought that up.

CHAIR REMPE: I think a lot of people have brought that up. You heard Sanjoy say it too.

MR. HALE: Yes, Sanjoy, I know.

CHAIR REMPE: And so, again, it's kind of your decision but I think that would be good. This is a little different, kind of jointly talking about what the path forward is.

But I'd rather have everybody's buy-in that it is worthwhile to spend the money to come back for full committee in July and to think about the options and --

MEMBER SKILLMAN: I think packaging the LOCA information, getting clarity between present condition, what will be for upright and how you got there so that we really don't have to retread how in the world could those temperatures be different?

MR. HALE: Yes, I thought we had the rackups, didn't we? Jay, didn't we? I thought we responded to that question.

MEMBER SKILLMAN: Not incrementally. You just said EPU and not EPU.

MR. HALE: Yes, but I thought we --

CHAIR REMPE: They actually did for the large-break LOCA and the small-break LOCA.

MR. JONES: Yes, we did provide --

CHAIR REMPE: You were the person who read, no. You were the person who read off the

numbers, yes.

MEMBER SKILLMAN: The question isn't us. It's the full committee.

CHAIR REMPE: Right.

(Simultaneous speaking.)

MEMBER SKILLMAN: And we're going to bring that in front of people who have not seen that.

MR. HALE: Okay, understood.

MEMBER SKILLMAN: And so the question is how to get through the full committee swiftly and focus on the steam generators, and it's by having that information as smooth as it can be and then either having a license condition or a commitment for the steam generator inspection, something like that.

I think that that might get us into that full committee meeting with the capability for our colleagues to be able to say got it, understand and I'm almost there or I'm there.

MR. HALE: We could provide that in advance as well to Weidong so he could distribute that to the members, the rackup.

CHAIR REMPE: I'd minimize the early discussion. And with Grand Gulf, didn't the staff give most of the information other than a couple of issues?

And you might want to work together on how to make sure we get through the information and have enough time for steam generator tube ruptures. Yes, sir.

MR. HOFFMAN: Dr. Rempe, I'm not sure if there were any comments from the other member who left early, just for completeness.

CHAIR REMPE: Stephen Schultz, is he who we're discussing?

(No response.)

CHAIR REMPE: I talked to him informally and so I don't know if second-hand information is worthwhile repeating, but the steam generator issue was the same thing that he had. He had -

MR. HOFFMAN: I was just curious if he had an open issue that we responded to.

CHAIR REMPE: He was fine with the way you responded to the field performance and so he appreciated that.

MR. HOFFMAN: Okay. So we have no open issues to go.

CHAIR REMPE: With that, I appreciate everybody who stuck around till the bitter end and have a good night and I'll close the meeting.

(Whereupon, the meeting in the above-

entitled matter was concluded at 6:22 p.m.)

St. Lucie Unit 2
Extended Power Uprate (EPU)
ACRS Subcommittee

June 22, 2012

Agenda

EPU Overview

- **Analyses**

- **Materials**

- **Acronyms**

FPL

St. Lucie Unit 2

- 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 - Westinghouse
- Unit output 907 MWe gross

FPL

St. Lucie

- **Original operating license issued in 1983**
- **Renewed operating license issued in 2003**
- **Installation of a new single-failure proof crane to support spent fuel dry storage operations in 2003**
- **Steam Generators (SGs) replaced in 2007**
- **Reactor Vessel Head was replaced in 2007**
- **Replaced 2 of 4 Reactor Coolant Pump motors in 2007 and 2011**
  - The remaining motor replacements planned for 2012 and 2014

FPL

St. Lucie

- **Licensed Core Power**
  - Original Licensed Core Power 2560 MWt
  - Current Licensed Core Power 2700 MWt
    - -- 5.5 % Stretch Uprate (1985)
  - EPU Core Power 3020 MWt
    - -- Implement 2012

FPL

FPL is requesting approval for a 12% power level increase for St. Lucie Unit 2

- **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**

FPL.

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 2 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***

FPL

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**

FPL

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 (ºF)	571.6	573.5	578.5	+5.0
Vessel Inlet (ºF)	548.0	549.0	551.0	+2.0
Vessel Outlet (ºF)	595.2	598.0	606.0	+8.0
Delta T (ºF)	47.2	49.0	55.0	+6.0
Thermal Design Flow (gpm/loop)	185,000	187,500	187,500	0
Core Bypass (%)	3.7	3.7	3.7	0
Steam Pressure (psia)	893	896	895	-1
Moisture Carryover (maximum, %)	0.20	0.10	0.10	0
Steam Mass Flow (10^6 lb/hr)	11.19	11.80	13.42	+1.62

FPL

Modifications will be made in support of safety

- Nuclear Steam Supply System (NSSS) setpoints
- Control room air conditioning margin improvement
- Charging pump control circuit modification
- Chemical and Volume Control System (CVCS) vents
- 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
- Component Cooling Water piping support modifications
- Raise Reactor Protection System (RPS) Steam Generator low-level trip setpoint (plant risk profile enhancement)

FPL

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
  - Upgrade steam and power conversion system instrumentation
  - Modify Main Steam piping supports
- **Condensate and Feedwater**
  - Replace Main Feedwater and Condensate Pumps
  - Upgrade Main Feedwater Regulating Valves and controls
  - Replace #5 High Pressure Feedwater Heaters
  - Replace #4 Low Pressure Feedwater Heaters
  - Upgrade Main Condenser
  - Modify Main Feedwater and Condensate 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

- Continued on next page -

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
  - Replace Main Transformers
  - Switchyard modifications

FPL

Agenda

- **EPU Overview**
  - Introduction………………………………………… Joe Jensen
  - Plant Changes……………………………………… Jack Hoffman
- **Analyses**
  - Fuel and Core …………………...……………… Jay Kabadi
  - Safety Analysis …………………………………. Jay Kabadi
  - TCD / LBLOCA (Proprietary) …………………… Jay Kabadi
- **Materials**
  - Steam Generators (Proprietary) ……….......……….Rudy Gil
- **Acronyms**

FPL

Fuel design maintains margin to limits

Fuel Design

- **16x16 CE Standard Fuel Design – same as in previous cycles**
  - Includes Inconel Top Grid design which was implemented to increase grid-to-rod fretting margin
- **Peak rod and assembly burnup will be maintained within current limits**

FPL

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 1.60
  - Linear heat rate COLR limit remains at 12.5 kW/ft
- **Normal incore fuel management methods utilized to meet reduced limits with increased energy needs**
  - Feed batch size and enrichment
    - -- Maximum planar average enrichment increased from 4.5 wt% to 4.6 wt% U-235
  - Burnable absorber placement
  - Core loading pattern

FPL

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

FPL

Approved methods used for safety analysis as supplemented by subsequent RAI responses

- **Codes and methodologies**
  - CEFLASH-4A/CEFLASH-4AS: large & small break LOCA
  - RETRAN: Non-LOCA transients
  - VIPRE-W: DNB analysis of the nuclear fuel

FPL.

Safety analyses demonstrate acceptable results

- **Key changes beneficial to safety analysis**
  - Reduction of Radial Peaking Factor (F_r^T)
- **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
    - -- Pressurizer level (nominal ± uncertainty)

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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 30% 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)**
- **Pressurizer Safety Valve setpoint tolerance increased from ±2% to ±3%**
- **SIT and Refueling Water Tank (RWT) boron concentration requirement revised from between 1720ppm and 2100ppm to between 1900ppm and 2200ppm**

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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	RETRAN, CESEC, & TWINKLE/FACTRAN Computer Codes	RETRAN & TWINKLE/FACTRAN Computer Codes
Thermal-Hydraulic Core Analyses	VIPRE-W	VIPRE-W
	ABB-NV CHF correlation W-3 CHF Correlation (SLB)	ABB-NV CHF correlation W-3 CHF Correlation (SLB)

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 ≥ 1.42	1.44
	Locked Rotor (PA)	Rods-in-DNB ≤ 19.7%	0%
RCS Overheating (Decrease in Secondary Heat Removal)	Loss of Condenser Vacuum (AOO)	RCS Press. ≤ 2750 psia	2669 psia
		MSS Press. ≤ 1100 psia	1094 psia
	Loss of Load to one SG (Asymmetric Steam Generator Transient) (AOO)	MDNBR ≥ 1.42	2.22
	Loss of Feedwater (AOO)	Liq. Vol. ≤ Pressurizer Vol. (1519 ft^3)	1263 ft^3
		RCS Subcooling ≥ 0°F	85°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 Overheating	FW Line Break (PA)	MDNBR ≥ 1.42	2.21
		RCS Pressure ≤ 3000 psia (Large Breaks) RCS Pressure ≤ 2750 psia (Small Breaks)	2704 psia 2700 psia
		MSS Pressure ≤ 1100 psia	1094 psia
RCS Overcooling (Increase in Secondary Heat Removal)	Feedwater Malfunction (AOO)	Increased FW Flow MDNBR ≥ 1.42	1.96
		Decreased FW Temperature MDNBR ≥ 1.42	1.97
	HFP Pre-scram MSLB (PA)	Rods-in-DNB ≤ 1.2% (OC) & ≤ 21% (IC)	0%
		Fuel Melt ≤ 0.29% (OC) & ≤ 4.5% (IC)	0%
	HZP Post-scram MSLB (PA)	Rods-in-DNB ≤ 1.2% (OC) & ≤ 21% (IC)	0%
		Fuel Melt ≤ 0.29% (OC) & ≤ 4.5% (IC)	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	CEA Withdrawal @ HZP (AOO)	MDNBR ≥ 1.26	1.284
		Fuel CL Temp. ≤ 4717°F	3432 °F
	CEA Withdrawal @ Power (AOO)	MDNBR ≥ 1.42	1.74
		RCS Press. ≤ 2750 psia	2485 psia
	CEA Malfunction (AOO)	MDNBR ≥ 1.42	> 1.42
		Peak LHR ≤ 22 kW/ft	13.76 kW/ft
	CEA Ejection (PA)	RCS Press. ≤ 3000 psia	< 2800 psia
		Fuel Enthalpy ≤ 200 cal/g	151.5 cal/g
		Rods-in-DNB ≤ 9.5%	< 9.5%
		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)	> 15 min.
		Time-to-Criticality ≥ 30 min. (Mode 6)	> 30 min.
RCS Mass Addition	Inadvertent ECCS/CVCS (AOO)	Liq. Vol. ≤ Pressurizer Vol.	~1512 ft^3 @ 20 min. after High Level Alarm
RCS Depressurization	Inadvertent Opening of a Pressurizer PORV (AOO)	MDNBR ≥ 1.42	1.73
		Liq. Vol. ≤ Pressurizer Vol.	1519 ft^3 @ ~3 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	3030.0
Peak Linear Heat Rate (kW/ft)	13.0	13.0
Steam Generator Tube Plugging (%)	30	10
Minimum SIT Pressure (psig)	485	485

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Small break LOCA analysis demonstrates acceptable results and is not impacted by thermal conductivity degradation

	Pre – EPU (Appendix K)	EPU (Appendix K)	Limit
Limiting Break Size (ft^2)	0.05	0.05	-
PCT (°F)	1943	1903	2200
Maximum Transient Local Oxidation (%)	9.80	9.21	17.0
Maximum Core-Wide Oxidation (%)	0.64	0.94	1.0

Agenda

Acronyms

AC	Alternating Current
AOO	Anticipated Operational Occurrences
AVB	Anti-Vibration Bar
BAMT	Boric Acid Makeup Tank
BOP	Balance of plant
CHF	Critical Heat Flux
CLB	Current Licensing Basis
COLR	Core Operating Limits Report
CVCS	Chemical and Volume Control System
DNB	Departure From Nucleate Boiling
ECCS	Emergency Core Cooling System
EHC	Electro Hydraulic Control
EPU	Extended Power Uprate
EQ	Environmental Qualification
F	Fahrenheit
F_r^T	Total Radial Peaking Factor
ft	Feet
FW	Feed Water
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
KW	Kilowatt
LEFM	Leading Edge Flow Meter
LHGR	Linear Heat Generation Rate
Liq	Liquid
LOCA	Loss of Coolant Accident
MDNBR	Minimum Departure From Nucleate Boiling
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
PSIA	Pounds 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
SLB	Steam Line Break
SG	Steam Generator
V	Velocity
ρ	Density

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LEFM ✓+ System Overview

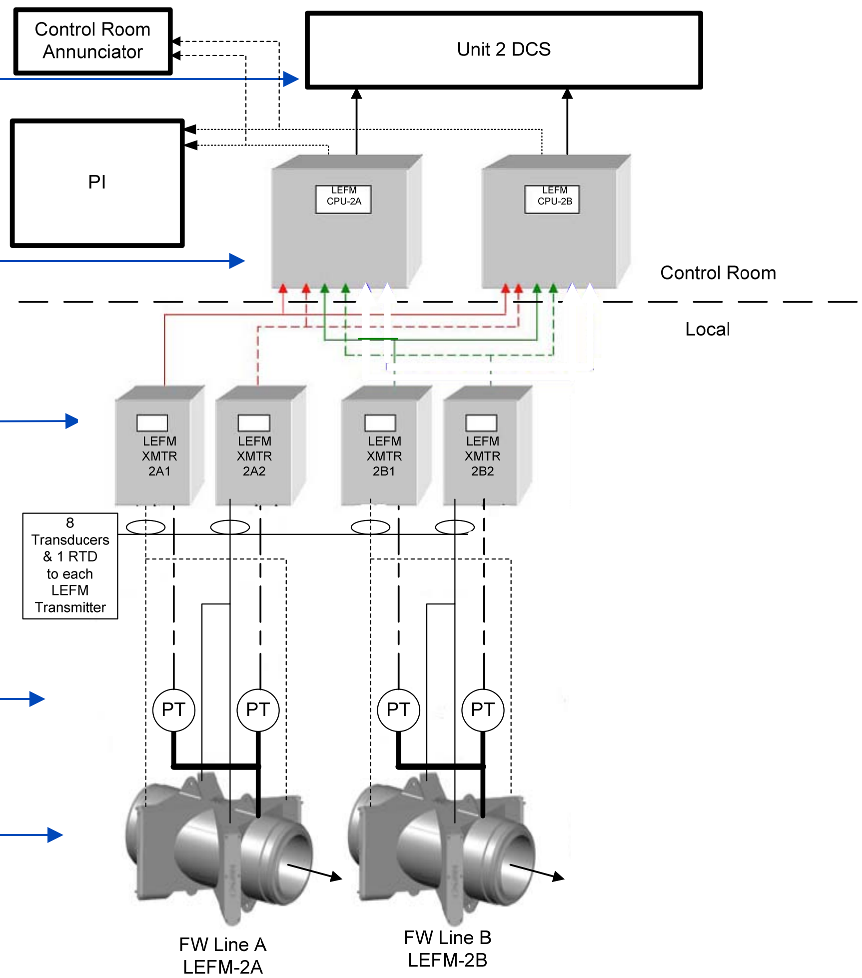
Current plant DCS system
Contains calorimetric calculation

LEFM CPUs
Calculates FW total mass flow & monitors LEFM system condition

LEFM Transmitters
Receives & calculates SG system flow from transducers in spool pieces

FW Pressure Transmitters
Used to determine FW density

LEFM Spool Pieces
Contain LEFM transducers



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ACRS Subcommittee on Power Uprates

NRC Staff Review
St. Lucie, Unit 2
Extended Power Uprate

June 22, 2012

Opening Remarks

Michele G. Evans

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
  - Inadvertent ECCS actuation
  - CVCS malfunction

Introduction

Tracy J. Orf

Project Manager

Division of Operating Reactor Licensing

Office of Nuclear Reactor Regulation

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Introduction

- Background
  - ❖ St. Lucie 2 EPU Application – February 25, 2011
  - ❖ 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
  - ❖ Supplemental responses to NRC staff RAIs and Audits
  - ❖ EPU Implementation
  - ❖ Fuel storage criticality analysis separated into separate license amendment for scheduling purposes

Topics for Subcommittee

- EPU Overview
- Fuel and Core
- Safety Analyses
- Materials – Steam Generators

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St. Lucie Unit 2 EPU
Accident Analyses

Samuel Miranda and Benjamin Parks
Reactor Systems Branch
Office of Nuclear Reactor Regulation

EPUs for St. Lucie Units 1 and 2

	Unit 1	Unit 2
Operating license	1976	1983
Current licensed core power (MWt)	2700	2700
EPU core power (MWt)	3020	3020
Fuel Supplier	AREVA	Westinghouse
Audited by NRC staff	Jan 2012	Feb 2012

Review of Mass Addition Event Analyses

- Inadvertent ECCS actuation
- CVCS Malfunction
- Inadvertent pressurizer PORV opening

Inadvertent Actuation of ECCS and CVCS Malfunction

- Charging pumps 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

- Charging pumps (PDPs) are in the ECCS and started by the SIAS
- Charging pumps can fill the pressurizer and can cause the PORVs to open and discharge water
- PORVs that relieve water are assumed to stick open

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 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.

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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 < 1 min
  - Pressurizer fills in < 3 min
  - Charging pumps can cause PORVs to open and relieve water
  - A PORV can stick open (SBLOCA)

Review of LOCA

- Appendix K Large Break
  - Analysis accordant with CENPD-132, Supplement 4-P-A, "*Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model*"
  - Limiting PCT occurs during late reflood
- Small Break
  - Licensee implemented CENPD-137, Supplement 2-P-A (S2M), "Calculative Methods for the ABB CE Small Break LOCA Evaluation Model"

Appendix K Large Break LOCA

- PCT occurs during late reflood
  - 1.2 multiplier applied to ANS 1971 standard for decay heat
  - Decay heat is more significant than fuel initial stored energy for later PCT
  - Sensitivity study to see how TCD affected blowdown PCT
    - Substantial increase in stored energy required to drive blowdown peak higher than the reflood peak

Appendix K Large Break LOCA

- Downcomer Boiling
  - CE design of large SITs ensure downcomer is filled when the SITs inject
  - Sensitivity studies were provided to demonstrate that downcomer boiling is not a concern

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Appendix K Large Break LOCA

- Conclusions
  - Results demonstrate compliance with 10 CFR 50.46 requirements

Parameters	Pre- EPU	EPU	10 CFR 50.46 Limits
Peak Clad Temperature	2104 °F	2087 °F	2200 °F
Maximum Local Oxidation	16.06	14.48	17.0%
Maximum Total Core-Wide Oxidation (All Fuel)	0.789	0.954	1.0%

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Small Break LOCA

- Break Spectrum
  – Supplemental analysis with more refined break spectrum provided
  – analysis of a severed injection line break provided

Small Break LOCA

- Conclusions
  - Results demonstrate compliance with 50.46 requirements

Parameters	Pre-EPU Analysis	EPU Analysis	10 CFR 50.46 Limits
Limiting Break Size	0.05 ft^2	0.05 ft^2	NA
Peak Clad Temperature	1943 °F	1903 °F	2200 °F
Maximum Local Oxidation	9.80 %	9. 21%	17.0%
Maximum Total Core-Wide Oxidation (All Fuel)	0.64%	0.94%	1.0%