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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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SUBCOMMITTEE ON POWER UPRATES

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OPEN SESSION

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WEDNESDAY

DECEMBER 14, 2011

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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., William J. Shack, Chairman, presiding.

SUBCOMMITTEE MEMBERS PRESENT:

WILLIAM J. SHACK, Chairman

SAID ABDEL-KHALIK

J. SAM ARMIJO

JOHN D. SIEBER

GORDON R. SKILLMAN

CONSULTANTS TO THE SUBCOMMITTEE PRESENT:

THOMAS S. KRESS

GRAHAM B. WALLIS

NRC STAFF PRESENT:

WEIDONG WANG, Designated Federal Official

MICHELE EVANS

DOUG BROADDUS

JASON PAIGE

BENJAMIN PARKS

JEFF POEHLER

SAMUEL MIRANDA

CHAKRAPANI BASAVARAJU

GEORGE LAPINSKY (via telephone)

ANTHONY ULSES

ALSO PRESENT:

MIKE KILEY

STEVE HALE

CARL O'FARRILL

SAM SHAFER

ANDY ZIELONKA

RICH TUCKER

RUDY GIL

LIZ ABBOTT

KIM ROMANKO

TOM RODACK

ED MONAHAN

CESARE FREPOLI

MIKE WATSON

BOB BAIN

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P R O C E E D I N G S

8:29 a.m.

CHAIR SHACK: The meeting will now come to order. This is a meeting of the Power Uprate Subcommittee, a standing subcommittee of the Advisory Committee on Reactor Safeguards. I'm Bill Shack, chairman of the subcommittee. ACRS members in attendance are Dick Skillman, Sam Armijo, Jack Sieber, Said Abdel-Khalik, and our consultants Tom Kress and Graham Wallis. Weidong Wang of the ACRS staff is the designated federal official for this meeting, and Mike Ryan may or may not attend the meeting.

In this meeting, the subcommittee will review Turkey Point Power Units 3 and 4 License Amendment Requests for Extended Power Uprate. We will hear presentations from the NRC staff and the representatives from the Applicant, Florida Power and Light Company. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

For the agenda items seven and eight on safety analyses, the presentation will be closed in order to discuss information that is proprietary to the Applicants and its contractors, pursuant to 5 USC 552(b)(C)(4). Attendance of this portion of the

meeting dealing with such information will be limited to the NRC staff and its consultants, Progress Energy Incorporated, 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 and the closure of the public phone line for the closed portion.

The subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the full committee. The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register. A transcript of the meeting is being kept and will be made available, as stated in the Federal Register notice. Therefore, we request the participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee. The participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard.

We will now proceed with the meeting. And I believe Michele Evans will open for the staff.

MS. EVANS: Thank you. Good morning. My

name is Michele Evans. I'm the Director of the Division of Operating Reactor Licensing and NRR. I recently assumed that position from Joe Giitter back on about October 1st. I appreciate the opportunity to brief this ACRS Power Uprate Subcommittee this morning.

In the interest of time, I will keep my remarks brief. At this meeting, the NRC staff will present to you the results of our very thorough safety and technical review of the licensee's application. The thoroughness of the review is supported by the fact that we had several pre-application and public meetings with the licensee in which the licensee provided a schedule of the overall proposed EPU implementation plan and technical concerns were identified, discussed, and resolved in a timely manner.

During the course of our review, the staff had frequent communications with the licensee, as well as several audits and numerous conference calls, to discuss the EPU application and its supplemental responses to several rounds of requests for additional information covering multiple technical disciplines. Some of the more challenging review areas that you'll hear about today include the safety analyses for

inadvertent opening of a PORV and feedwater line break. These were requested by the staff and are not part of Turkey Point's current licensing basis, but the staff believe they were necessary to complete its review.

Second, the boron precipitation analysis and the unique approach to mitigate the onset of boric acid precipitation and the steps the staff took to complete its review. And, lastly, the staff recently became aware of an emerging issue regarding a fuel thermal conductivity under-prediction that may affect the best estimate upper tolerance limit of the peak cladding temperature for PWR large-break loss of coolant accidents and could impact the ECCS evaluation for the Turkey Point EPU. The licensee will provide a presentation on this issue and its plans for resolving this item, and the staff will be available to address any questions you may have.

As presented in the draft safety evaluation, which was provided to ACRS on November 23rd, there were five open technical issues in the NRC staff's review of the licensee's proposed EPU application. Later during this meeting, the staff will provide additional information on these open items and their actions to close them.

Specifically, we'd like to give our thanks to the ACRS staff who assisted us with preparations for this meeting, Weidong Wang. Thank you.

At this point, I'd like to turn over the discussion to our NRR project manager, Jason Paige, who will introduce --

CHAIR SHACK: Michele, why is this an emerging issue? I mean, you had an information notice on this two years ago now. I would have thought that this, you know, would have been the first RAI that you'd ask any time somebody comes in with a LOCA analysis.

MS. EVANS: Well, I'm sure there will be discussion of it as you move forward. Emerging issue as in additional information identified in the last week.

MR. BROADDUS: One of the issues, Westinghouse had been working on an analysis and just recently provided that analysis to the staff back on December 6th. So that's the first time we actually had the specific information. That will be discussed further during the meeting, the specifics of that.

MS. EVANS: And I believe another information note was sent out yesterday. So there will be more dialogue on that.

MR. PAIGE: Thank you. Good morning. My name is Jason Paige, and I'm the project manager in NRR assigned to Turkey Point. As you know, we provided a draft safety evaluation without Section 2.8 on November 14th, 2011 and provided a draft safety evaluation including Section 2.8 with open items on November 23rd, 2011, giving the ACRS members less than 30 days to review the information supporting the Turkey Point EPU. The staff understands the burden that this placed on the members. On behalf of the staff, I would like to take this opportunity to publically thank the ACRS for accommodating the schedule and reviewing the proposed EPU in such a short turnaround. The staff appreciates the effort in this regard.

Today, you will hear presentations from Florida Power and Light Company and the NRC staff. The objective 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 Turkey Point EPU. On October 21st, 2010, the licensee submitted its License Amendment Request for Turkey Point Units 3 and 4 EPU. The proposed amendment will increase each unit's license core power level from 2300 megawatt-thermal to 2,644 megawatt-thermal. This represents a net increase in license core thermal power of 15 percent, including a 13 percent power uprate and a 1.7 percent measurement uncertainty recapture. This is a 20 percent increase from the original license thermal power.

The staff's method of review was based on review standard 001, which is NRC's review plan for EPUs. As you know, it provides a safety evaluation template, as well as matrices that cover the multiple technical areas that the staff is to review. There are no associated or linked licensing actions associated with this EPU application. FPL previously submitted two license amendments for Turkey Point, the AST amendment in 2009 and the spent fuel pool criticality analysis in 2010. The NRC staff approved the AST and spent fuel pool criticality applications on June 23rd and October 31st, 2011 respectively.

Finally, there were numerous supplements to the application responding to multiple staff RAIs.

Overall, there were approximately 45 supplemental responses which supported our draft safety evaluation. Also, the staff completed several audits to complete its review and resolve open items. The staff projects February 2012 to complete our review, and this would be in support of the licensee's schedule implementation in the first quarter of 2012 for Unit 3 and in the third quarter of 2012 for Unit 4.

This slide is the topics for today's discussion. FPL will start out providing an overview of the EPU and then presenting all materials and steam generators. FPL and the NRC staff will then each present their presentations on fuel and core and safety analyses. The NRC staff will then have a discussion and presentation on mechanical and civil engineering and human factors.

Finally, at the conclusion of the meeting, as needed, we can cover any open items in preparation for a full committee meeting. And also to note, if needed, there will be closed portions of this meeting during the afternoon session scheduled on the agenda for 2:45 p.m. So if there's any proprietary information that needs to be discussed, it can be deferred over to the designated closed session.

This concludes my presentation as far as

the introduction. Unless there are any questions, I would like to turn it over to the presentation to Mr. Mike Kiley and FPL. Mr. Mike Kiley is the site vice president for Turkey Point Nuclear Power Plant.

MR. KILEY: All right. Good morning. As Jason said, I'm the site vice president for the Turkey Point Nuclear Plant. With me today is two individuals. Sam Shafer to my far left. Sam has over 25 years in the operations department at Turkey Point, currently the assistant operations manager. And my immediate left is Steve Hale. Steve Hale is the director of licensing for the EPUs for Turkey Point.

So as you can imagine, this uprate was a significant undertaking. Not only will it increase the electrical output of the station, but it will also increase the equipment reliability and the availability for the units.

Turkey Point 3 and 4, to put it in context, there was five units at the Turkey Point site. Units 1 and 2 are fossil units that came online in the late 60s. Units 3 and 4 are the nuclear units we're discussing today. Unit 5 is a combined cycle gas unit that came on in the 2005 time frame.

CHAIR SHACK: Those fossil units I assume burn gas?

MR. KILEY: They have the ability to do gas or --

CHAIR SHACK: Oil. But they do burn gas at the moment?

MR. KILEY: That's correct. That's correct. And Unit 2 is currently not operating as a generating station. It's operating as a synchronous condenser unit. So Units 3 and 4 are three-loop Westinghouse PWRs. Bechtel was the design engineer for those sites.

The matching Westinghouse generators for the two units. The two units came online in 1972 and 1973 respectively. We did achieve our license renewal for both Units 3 and 4 in 2002. That extends the initial license to 2032 and 2033 respectively. The generational output of Unit 3 and 4 currently is 795 megawatts electric.

Additional modifications that we've done over the years at the station is we have included improvements as replacing the steam generators with Model 44f generators. Those generators were replaced in 1982 and 1983. We increased the number of safety-related diesels from two to four. One of the unique attributes of our system is that any one of the diesels can be cross-connected to literally supply any

power system at the stations. And both reactor heads were changed, as much of the industry did, in 2004 and 2005.

So as Jason mentioned, the original power thermal limit for the station was 2200 megawatt-thermal. It was increased in 1996 with a small uprate to 2300, and this extended power uprate will bring it to 2644.

CONSULTANT WALLIS: Could you tell me how far above sea level you are?

MR. KILEY: Units 3 and 4 are designed for 22 feet.

CONSULTANT WALLIS: Above mean sea level?

MR. KILEY: Correct.

CONSULTANT WALLIS: So when you have surges and things like that, does the water come pretty close to the limit?

MR. KILEY: No. Probably the most life-like example of that was during Hurricane Andrew that came to the site. You know, with the elevation of 22 feet during that Category 5 hurricane, the station saw no flood water that challenged any operating equipment whatsoever. Several of the people here today were actually here during Hurricane Andrew, Sam personally. So he could address any real questions as far as what

the site went through. So pending any questions --

CHAIR SHACK: But what is the storm surge that you're designed for?

MR. KILEY: Twenty-two.

CHAIR SHACK: Twenty-two. That is the -- and the Andrew storm surge was?

MR. HALE: I think it was 14 on the north end of the storm. It was about 14 feet. I'm sorry. Steve Hale, Florida Power and Light.

MR. KILEY: So pending any questions for me, that's the extent of the introductory comments. I'd like to turn it over to Steve Hale. He'll go through in much more detail the modifications that we're going to be implementing at the station.

MR. HALE: As Mike said, I'm Steve Hale. I'm the licensing director for the Turkey Point extended power uprate licensing effort. As Mike indicated, we're implementing an approximate 15 percent power uprate, which includes a 13 percent extended power uprate in addition to a 1.7 percent measurement uncertainty recapture.

Some of the aspects of the EPU. We can accommodate classic NPSH on the ECCS pumps without any credit for containment overpressure. We are not making any fuel designs specifically for an extended

power uprate. As Jason mentioned, we did submit an alternate source term license amendment to which accommodated EPU conditions, and that was approved in June of 2011. And we also submitted a spent fuel criticality license amendment. That was amendment number 207, and that was approved in October 2011.

CHAIR SHACK: On your measurement uncertainty recapture, your power measurement uncertainty is 0.3 percent, which I think, as far as I know, sets a new record. I mean --

MR. HALE: No. If I could, I was involved with the Seabrook uprate. The power uncertainty for Seabrook is 0.3 percent.

CHAIR SHACK: Okay. Because I have 0.5 for Indian Point, 0.4 for Susquehanna. 0.6 for Beaver Valley, 0.6 for Point Beach. I thought 0.3 was a new -- okay. I missed one.

MR. HALE: No, no. I was directly involved, so I can speak specifically to the Seabrook.

CHAIR SHACK: I looked at the way that's done. When you're starting to slice it that fine, how do you know that the mockup that you've created in order to do this measurement, in fact, is a mockup that's close enough to give you uncertainties as low as they are?

MR. HALE: Well, that's really the benefit of going with a Cameron device. I've actually witnessed the testing they do at the test facility. They actually mimic or, you know, set it up where it's very similar to your own piping --

CHAIR SHACK: Very similar and exactly the same are the things that bother me when I'm talking about measuring uncertainties as slow as we are here in terms of the flow.

MR. HALE: The details of the Cameron check-plus device, you know, have certainly gone through quite a bit of scrutiny. In fact, the Seabrook effort, we were the first ones to go through after the Byron/Bravewood issues with overpower. I know the NRC staff actually participated in the review of the testing that was done at all the labs, and it's undergone quite a bit of scrutiny in terms of that. But there's other aspects besides just the Caldon device itself. You know, there are other inputs into the uncertainty, and you have to go in and look at those specifically, you know, the other inputs into your calorimetric. So we feel very confident that it reflects the actual power uncertainty.

MEMBER ARMIJO: I have a couple of questions on your fuel. You have, apparently, a mixed

core with this debris-resistant fuel assembly and an upgrade design, and that, you say, is not related to the EPU. That's just the design change you normally we're going to make?

MR. HALE: Carl O'Farrill is our fuels manager. He was going to get into speaking to that a little later, but we can answer your question.

MEMBER ARMIJO: Yes, if you could let me know now.

MR. O'FARRILL: We will be operating with a mixed core. We had implemented the upgrade fuel design in previous cycles, and we had done that under 10 CFR 50.59.

MEMBER ARMIJO: And so you're transitioning entirely to the upgrade design?

MR. O'FARRILL: That is correct.

MEMBER ARMIJO: And is that Zirlo cladding or what kind of cladding?

MR. O'FARRILL: It is Zirlo cladding.

MEMBER ARMIJO: On both the --

MR. O'FARRILL: On both the current fuel that we have, as well as the upgrade fuel.

MEMBER ARMIJO: Okay. Thank you.

MR. HALE: Any other questions before we --

MEMBER SKILLMAN: Yes, I do. I'm Dick Skillman. The staff's letter comments the reactor coolant thermal design flow will increase approximately 2.2 percent, reflecting a slight reduction of flow resistance from the new fuel assembly as well, also, crediting the additional flow margin currently available. Would you please describe what that additional flow margin is, please?

MR. HALE: Well, the actual flow certainly is a lot higher than what you assume in your safety analysis. So the thermal design flow that we're talking about there is what we input into our safety analysis. We are required by tech specs to confirm and measure our flow periodically, and the actual flow has to be above that input flow. So we're very familiar with, you know, what our actual flows are, and they are in excess of what we assume in the safety analysis.

MEMBER SKILLMAN: How was that documented?

MR. SHAFER: I believe we perform a surveillance to document it, so the testing reactor engineering does get involved -- I'm sorry. I'm Sam Shafer from FPL. They document that per the surveillance procedure. We document it every 90 days after coming out of a refueling outage to make sure

that we take the RCS flow and verify it with a calorimetric.

MEMBER SKILLMAN: Thank you.

MR. SHAFER: You're welcome, sir.

CONSULTANT KRESS: Did you not have to increase the enrichment for the power uprate and the fuel?

MR. O'FARRILL: Yes.

CONSULTANT KRESS: But that's not a fuel design change?

MR. O'FARRILL: Well, that's normal fuel management that we do for normal core designs. This is Carl O'Farrill, by the way. And we do change enrichments from core design to core design. And two ways we can accommodate the uprate is increasing the amount of fresh fuel we load into the fuel in each core design and increasing the enrichment. So we do a balance between increasing the enrichment and increasing the batch size for the reload.

MEMBER SIEBER: Typically, the enrichment is limited by what you're allowed to put into your spent fuel pool, and I presume that your enrichment, maximum enrichment is under five percent?

MR. O'FARRILL: That is correct. We're actually making a revision to go from four and a half

percent to five percent as part of the EPU.

MEMBER SIEBER: Okay. And what kind of fuel -- did you have to make any changes to your fuel racks or your loading pattern in the spent fuel pool?

MR. O'FARRILL: Well, we had previously done the analysis, which we had mentioned earlier that the criticality analysis was approved when we accommodated, there's two effects you want to accommodate. It's not only the increased enrichment but the operating conditions for that fuel assembly. You want to capture those two and uprate conditions to make sure you capture the reactivity effects in the spent fuel storage. So we did that, and we already submitted that analysis that accommodated that. And in that analysis we did have to make configuration changes in the spent fuel storage.

MEMBER SIEBER: And what changes did you make? You know, one thing you can do is relocate assemblies from various places so that they become less reactive or you can actually modify the racks. Did you do any modifications of racks, or is this stage a selective pattern for --

MR. O'FARRILL: It is the selective pattern that we use. We did not, we didn't do any modifications to the rack.

MEMBER SIEBER: Okay. And the heat load is going to be higher than it was before. Have you taken that into account? For example, if you're to lose all makeup water and all cooling through the spent fuel pool, do you know by what extent that we'll reduce the boil-off time until you get down to, the water level gets down to the active fuel? Have you done any calculations like that?

MR. HALE: Yes. That's part of the analysis and evaluations we did.

MEMBER SIEBER: Yes. And could you give us an idea, for example, how the boil-off time has changed in terms of hours, minutes, or what have you?

MR. HALE: We'll have to, we'll get back to you on that one.

MR. O'FARRILL: To get those exact numbers, I don't have them readily available. But we can get back to you on --

MEMBER SIEBER: Well, I think that, from recent lessons learned, that's something that we all need to think about.

MR. O'FARRILL: Well, we did specific calculations for the boil-off.

MEMBER SIEBER: I'm sure you did. I'm just curious as to what the answer is.

MR. O'FARRILL: Okay.

MEMBER SIEBER: I'd like to know how long it will last without the input from water heat removal.

MR. O'FARRILL: Understood. We'll follow up with that.

MEMBER ABDEL-KHALIK: How many open spaces do you have in the spent fuel pool if you are to allow for two full-core offloads and the new fuel at the beginning of refueling?

MR. HALE: I think we have separate spent fuel pits for --

MEMBER ABDEL-KHALIK: Yes, I understand.

MR. HALE: And we're also into a major ISFSI campaign, the, you know, independent spent fuel storage.

MEMBER ABDEL-KHALIK: I understand.

MR. HALE: Okay.

MEMBER ABDEL-KHALIK: So how many open spaces would you have if you allow for full-core offload and the new fuel load?

MR. HALE: I will have to get back to you on that.

MR. O'FARRILL: You're asking the status of our --

MEMBER ABDEL-KHALIK: Spent fuel pools.

MR. O'FARRILL: Fuel assemblies are in there now and how much remaining capacity do we have?

MEMBER ABDEL-KHALIK: Correct.

MEMBER SIEBER: I presume your core loading is 157 assemblies?

MR. O'FARRILL: It's 157 for the core. That's right.

MEMBER SIEBER: Makes sense.

MR. O'FARRILL: One of the things we did have, and we'll include that in a number, is that we have a cask area rack that is removable that we use for refueling outages to accommodate the full-core offload.

MEMBER SIEBER: Okay.

MR. O'FARRILL: Unfortunately, the cask loading campaigns, that rack is removed so we can place the cask there and offload the fuel into the casks.

MEMBER SIEBER: Okay, thank you.

MEMBER ABDEL-KHALIK: So you'll get back to us with that information?

MR. HALE: Yes, yes, we'll give you the numbers as to what our status is, our capacity in our pool and how much available empty spaces we have

currently.

MEMBER ABDEL-KHALIK: Correct.

MEMBER SIEBER: And how long it will take to boil off.

MR. HALE: And how long it will take to boil off.

MEMBER SIEBER: Thanks.

MR. HALE: Okay. Moving on, we have completed grid stability studies for the increases in power output. Of course, this would also include the impact of St. Lucie, which will be coming forward in the next few months before this committee. Our current plan is to implement the modifications during the spring of 2012 for Unit 3 and then the fall of 2012 for Unit 4.

CHAIR SHACK: Just looking historically at the data I have back from NUREG-1776, it says that up until about 2000 you had 13 loss of offsite power events, seven of those were grid related, which is like twice as many as anybody else. Has it gotten better since then?

MR. HALE: Yes. Actual transmission system has improved over the years. In fact, we direct that as part of our customer service aspects, but, yes, it has improved over the years.

CHAIR SHACK: Do you have any idea how many loss of offsite power events you've had since, say, 2000?

MR. HALE: I can't speak to that. I'd have to get back to you with those numbers.

MEMBER SIEBER: Let me -- maybe it's out of sequence or out of your thought pattern. But there are a number of three-loop Westinghouse PWRs that are subatmospheric. Yours are not subatmospheric.

MR. HALE: No. We're a classic post-tension containment Bechtel --

MEMBER SIEBER: Okay.

MR. HALE: No ice condenser.

MEMBER SIEBER: Yes. Well, okay. They have some unique features of their own that you have to be careful of, which some Florida utilities are learning at the moment.

MR. HALE: Right.

MEMBER SIEBER: Even though you already have changed steam generators.

MR. HALE: Yes, we have.

MEMBER SIEBER: And so you, did you use your equipment hatch, or did you make a new hole?

MR. HALE: Actually, for Turkey Point, it was somewhat unique. We actually cut off and removed

the upper head of the steam generator, and we were able, by doing that, pull the lower assembly we called it out of the equipment hatch.

MEMBER SIEBER: Right. Okay. That's the way the design was supposed to work.

MR. HALE: Yes.

MEMBER SIEBER: Not everybody does it that way. Thanks.

MR. HALE: Moving on, you know, I was directly involved with the Point Beach effort, as well as Seabrook uprates. We have had a very active effort to ensure we factor in lessons learned. There's certainly plenty of lessons learned on uprates out there. We did our evaluations consistent with the current licensing basis, but, as Jason mentioned earlier, there were several events that we were required to address that were outside of our licensing basis, which I'm sure they'll speak to later.

Since we've already been approved for license renewal, license renewal was addressed, as required by RS-001. And so we ensured that we were addressing license renewal as we went through our EPU evaluations, both in the area of aging management, as well as TLAAs. And then the measurement uncertainty recapture portion of our submittal addressed the

regulatory guidance associated with measurement uncertainty recapture applications.

If there are no more questions there, I'd like to move on to plant modifications. As you might imagine, with an EPU of this magnitude there was quite a few modifications.

MEMBER ABDEL-KHALIK: Did you include an evaluation of the potential for axial offset anomaly. I assume that your power level currently is relatively low, but after the uprate how would that affect the plant's propensity for boron precipitation, crud precipitation, and axial offset anomaly?

MR. O'FARRILL: This is Carl O'Farrill. And we did take a look at that and looked at the increase in sub-cooled boiling duty that we have on the fuel assemblies and we looked at ways to manage that. And what we're doing is managing through the power distribution in our core design. So part of our core design process, because now we're going to a higher boiling duty at the uprate conditions, is to factor that in as we do our scoping analyses for the core design to assure ourselves that we have manageable boiling duties and are able to manage the crud deposition on the fuel.

MEMBER ABDEL-KHALIK: I assume you don't

have any problems with the axial offset anomaly at your current operating --

MR. O'FARRILL: We do not have any problems at all.

MEMBER ABDEL-KHALIK: Right. So where you are on the spectrum of severity of axial offset anomaly, as predicted, when you go to the uprate power condition in terms of the amount of boron expected to be precipitated in the crud.

MR. O'FARRILL: If I could restate that question, you're asking what are our projections for --

MEMBER ABDEL-KHALIK: Right. For boron precipitation.

MR. O'FARRILL: -- for boron precipitation on the fuel rods?

MEMBER ABDEL-KHALIK: Right.

MR. O'FARRILL: I believe we're talking on the order of, I'm trying to recall this from memory, it is less than 0.3 pound mass of --

MEMBER ABDEL-KHALIK: Is there any way that you can get us a sort of confirmed number, rather than a --

MR. O'FARRILL: Yes. I will get you --

MEMBER ABDEL-KHALIK: -- number from

memory?

MR. O'FARRILL: I'll confirm that number.

MEMBER ABDEL-KHALIK: Okay, thank you.

MEMBER SIEBER: Do you have in-core traveling probes?

MR. O'FARRILL: Yes, we do.

MEMBER SIEBER: How often do you take flux map and analyze it?

MR. O'FARRILL: It's a requirement to do that monthly.

MEMBER SIEBER: Okay. And you do it?

MR. O'FARRILL: Yes, that is in our tech specs.

MEMBER SIEBER: And all the probes work?

MR. O'FARRILL: All the thimble tubes are available to us.

MEMBER SIEBER: Okay.

MR. O'FARRILL: And we maintain the ability to move --

MEMBER SIEBER: You have arriving network --

MR. O'FARRILL: Right. We have five in-core detectors that actually travel at different locations throughout the cores, and that provides us complete coverage when we do that.

MEMBER SIEBER: Okay.

MR. SHAFER: This is Sam Shafer for Florida Power and Light. The answer to the question, he was right on track with it. We do have some discrepancies, but we do have the five-path and ten-path, so getting to all the core locations is not a problem to all the thimbles.

MEMBER SIEBER: Okay, great. Thanks.

MR. SHAFER: You're welcome, sir.

MR. HALE: Any other questions? Okay. Moving on, we did a number of engineering studies and analyses, as you might imagine, to address the changes and temperatures, pressures, and flows to the various systems. We developed secondary heat balances based on the new power levels. We evaluated the changes in the BOP parameters specifically for all the systems and components. We performed hydraulic analyses on feedwater and condensate and heater drain systems for both normal, off-normal, and transient conditions. And, again, there's a wealth of experience out there with these types of changes and modifications, and we've applied it across the board.

CONSULTANT KRESS: Did you have to add anything to the SSCs? Did you re-do your analysis to find out what are SSCs, and do you have to add any

when you make this many changes?

MR. HALE: There's a number of modifications we had to implement that were both in the area of safety analysis, as well as to attain the power output.

CONSULTANT KRESS: I'm not sure that answers my question.

MR. HALE: Okay. I'm sorry.

CONSULTANT KRESS: You have a number of components and systems.

MR. HALE: Right.

CONSULTANT KRESS: They're delegated as safety related and you have to treat them differently, and I was wondering if that list changed any.

MR. HALE: Not to a great extent. I would say no. Most of the hardware changes we're implementing are on the secondary side.

CONSULTANT KRESS: Secondary side.

MR. HALE: On the primary side, it was basically safety analyses and a number of setpoint changes, certainly, to accommodate those kind of things.

CONSULTANT KRESS: Thank you.

MEMBER SKILLMAN: Let me build onto Dr. Kress' question. In the staff letter, the statement

is made, "Due to increased core thermal power, the safety injection system required a minimum of two high-head safety injection pumps to maintain peak clad below acceptance." What's the change? Before you could have one, now you must have two?

MR. HALE: Yes. We actually restored to an original design. Turkey Point was originally, the high-pressure system was a shared system, two out of four high-head pumps for the two units. In 1996, we shifted to a one out of two per unit as part of the stretch power uprate that was implemented.

MEMBER SKILLMAN: Now you need two out of two?

MR. HALE: Now we've gone back to two out of four for the new uprate.

MEMBER SKILLMAN: So in response to Dr. Kress' question, you really have a high-head safety injection pump is added to your SSCs as a required design base for your uprate?

MR. HALE: Yes, you're correct. Yes.

MEMBER SKILLMAN: Let me go a little further. How does that change play into your PRA for the combined units? You say you got four high-head safety injection pumps. You used to need one. Now you must have two to maintain your thermal limits on

your fuel, but you've got a second unit sitting next door that might need two also. So where does that leave you in terms of equipment failure probabilities?

MR. HALE: It had minimal impact on the PRA.

MEMBER SKILLMAN: Is it included in the analysis?

MR. HALE: Yes, yes, yes.

MEMBER SKILLMAN: Thank you.

MR. HALE: Okay.

MEMBER ABDEL-KHALIK: You haven't really analyzed the case of those things happening at both units simultaneously, have you?

MR. HALE: No, our licensing --

MEMBER ABDEL-KHALIK: So I'm not sure how you're answering Mr. Skillman's question.

MR. HALE: Well, when you're looking at PRAs, certainly you're looking at contributions or the probability of core melts on an overall sense. The high-pressure ECCS pumps, you know, whether you're at one out of two or two out of four, is not a real high contributor to that probability. Now, from a licensing basis or standpoint, we do not assume dual unit LOCAs from a, you know --

MEMBER ABDEL-KHALIK: I understand.

MR. HALE: Okay. If you look at --

CONSULTANT KRESS: Do you assume dual unit loss of off-site power?

MR. HALE: Yes, we do. Yes, we do.

CONSULTANT KRESS: But that's part of your PRA?

MR. HALE: Yes, yes.

MEMBER SKILLMAN: Before we go on, I found this intriguing comment that I need to ask. A comment was made that you're going to install reach rods in valves 3867 and 4867. Reach rods went out with Liberty ships. What's with the reach rods?

MR. HALE: Turkey Point is still a manual plant. In other words, we do not have, you know, say, some of the later plants, which were, you know, all the actions could be accomplished from the control room in terms of motor-operated valves and things of that sort. So we're one of the older plants, and we still make use of reach rods on valves for protection of the operators from high-radiation areas and that sort of thing post accident.

MEMBER SKILLMAN: What are these valves, please?

MR. HALE: They're associated with Emergency Core Cooling system.

MR. SHAFER: Sam Shafer, Florida Power and Light. The three and four Type 867 is the inlet isolation valve for cold leg safety injection to both of our units. What the purpose of the valve is, it branches off to two motor-operated valves, which then injects into all three loops. The reason that we had to get the reach rod on there from the analysis is, if we did have a failure of that component, we will be able to take manual control of it when I have to go over to the hot leg injection. So we're not going into both hot and cold legs for the uprate, so that's why we had to include the reach rod to make sure the operator doesn't get overexposed to doses. They'll be able to close that and accomplish the function to make sure they're not injection cold leg and hot leg.

MEMBER SKILLMAN: Okay. Just stick with me here, Sam. You're over in ops, right?

MR. SHAFER: Yes, sir.

MEMBER SKILLMAN: Reach rods normally get rusty and don't get exercised.

MR. SHAFER: That is correct, sir.

MEMBER SKILLMAN: So how do you make sure this pair of reach rods, because they normally have universals and toggles and so on, how do you ensure that these are fully --

MR. SHAFER: We have a normal -- for that specific one, there will be an 18-month PM that's performed on it. All the other reach rods in the plant we have normal periodicities, which we go through and we physically go out not only to exercise it, they go out and look to physical linkages, the goob and lube we call it, as necessary to make sure that there's no interruptions or obstacles in the way that would prevent it from operating.

MEMBER SKILLMAN: Thank you, Sam.

MR. SHAFER: You're welcome, sir.

MEMBER SIEBER: You do this testing of the reach rod valve system while the system is operating in a configuration that you would expect to have to operate it under emergency condition? In other words, under certain flow conditions, it's much more difficult to open or close a valve than it is when the system is shut down, for example. So you do it under actual plant conditions, this test of operating valves with reach rods or manual wheels; is that correct or not?

MR. SHAFER: That's partially true. On some of the valves, for instance when the RHR system is in service, the bypass valves around the RHR heat exchanges do have the reach rod connections on them.

We do manipulate those while the RHR system is in service. Another one would be the full-flow system of our residual heat removal system that has the reach rods for using for alternate safety injection in the event that we had a problem. Those we do operate with real system pressure on it. There's some --

MEMBER SIEBER: The ones I'm concerned about are the ones that you test and declare operable when the system isn't in service, where the DPs aren't across the valves and so forth. Do you have any of those situations?

MR. SHAFER: Sir, I would have to get back with you on that. I don't have that specific information.

MEMBER SIEBER: Yes. Well, even in motor-operated valves, that's one of the areas many years ago, 25 to 30 years ago, that became a problem because the valve would operate during the test conditions and test setup, but it would not operate during the operating condition you expected during an accident. That's where all that testing came from. So I'm just curious as to how you test manually-operated valves that are important in emergency operations.

MR. SHAFER: Okay. We'll try to get you, we'll get that answer for you.

MEMBER SIEBER: Okay, thanks.

MR. SHAFER: You're welcome, sir.

MR. HALE: Okay. Moving on to just to give you an idea of various parameters, looking at core power, no change in RCS pressure, certainly some changes in rack coolant system temperatures. As we spoke earlier, the thermal design flow assumptions and safety analysis is going up, which carryover is not --

MEMBER ABDEL-KHALIK: And the decision as to the amount of increase in thermal design flow is based on historical data from the surveillances that you have to do on --

MR. HALE: Yes. Well, and also we want to ensure we maintain certainly a sufficient margin between what's assumed and what we actually measure.

MEMBER ABDEL-KHALIK: So what is the minimum measured flow historically?

MR. HALE: I can't speak to that. I don't know what the actual values --

MEMBER ABDEL-KHALIK: Is there any way we can get that information?

MR. HALE: Yes.

MEMBER ABDEL-KHALIK: Thank you.

MR. HALE: And then, of course, a fairly significant increase in steam mass flow as a result of

the uprate. Moving on, I wanted to highlight the modifications we're making just for the safety analysis, and then I'll talk about some of the modifications we're making to achieve the uprated power level.

As with all uprates and changes in power level, there will be a number of changes in triple setpoints. The pressurizer level program is changing as a result of higher temperatures. We are tightening the safety valve lift settings. Hot leg injection flow path, we spoke to that. That was the reach rod on the valve that we were speaking of. We have modified our emergency containment coolers auto-start logic to ensure that we have at least two emergency containment coolers operating at all times post accident. We have made some --

CONSULTANT WALLIS: Have you had history of investigating water hammer in those coolers?

MR. HALE: No, we don't. You know, it's a pretty smooth operating system.

CONSULTANT WALLIS: How about those, some of those containment coolers have a problem that they lose water and you bring water back in again?

MR. HALE: Right, right.

CONSULTANT WALLIS: You don't have a

problem with that?

MR. HALE: No, no, we haven't had a problem with that at all. We're changing main steam safety valves. We're also modifying the main steam isolation and main steam check valves. Feed water isolation valves, we're making some modifications to those, as well, to support the MUR. We're installing the LEFM, the check plus. We are refurbishing the auxiliary feed pumps. That is to restore them to their design flow rate capability.

MEMBER ABDEL-KHALIK: How much degradation has already occurred?

MR. HALE: I guess the flows, I don't know if I can speak to the exact flows. I don't know if someone here can speak to that. But they're not meeting their design specifications. They certainly meet the tech spec requirements.

MEMBER ABDEL-KHALIK: Right.

MR. HALE: But because we need some additional auxiliary feedwater flow to support the EPU, by refurbishing the pumps we can restore them to their design capability. And I think it's on the order of, it's like 373, 370 gpm, somewhere in that range, versus 310 to 373 as the increase in the actual tech spec flow capability or the license flow

capability.

MEMBER ABDEL-KHALIK: But I guess the question is how much degradation has actually occurred and necessitated this refurbishment?

MR. HALE: I'll have to get back to you on that. We'll get the actual flow numbers. We're making some modifications to the aux feedwater control valves. That's to give us some additional travel on the valves to support the additional flow. There are some safety-related piping modifications required as a result of changes in loading as a result of increased flows, that sort of thing. We're installing some additional jet impingement shields.

Tech Support Center modifications. This is just to add some additional shielding based on the relative location of Tech Support Center to the containment required some additional shielding as a result of the EPU. And talking about spent fuel cooling capacity, we are looking to supplement the existing spent fuel cooling system with additional cooling capacity as a result of the increase in loads.

MEMBER SKILLMAN: Two questions. Stay on that slide, please, Slide 12. Main steam safety valve setpoint changes, are you also changing the area on your safety and relief valves, are you changing the

orifice-ing in your --

MR. HALE: No, no. It's strictly a change in the lift setpoints.

MEMBER SKILLMAN: And has your analyses demonstrated the current area is acceptable --

MR. HALE: Yes.

MEMBER SKILLMAN: -- with the blowdown rate you need?

MR. HALE: Yes.

MEMBER SKILLMAN: Okay. Another question. You've gone to Model F generators. The distinctive change, I think, for the Fs is where your emergency feedwater is injected into the tube bundle. As I recall, that was one of the historical changes Westinghouse made.

MR. HALE: Actually, for Turkey Point, the aux feed is injected into the feedwater lines outside containment, so it goes through the sparger and the J-tubes.

MEMBER SKILLMAN: Okay. Here's where I was going. You've added enough reactivity in your moderator temperature coefficient to make these machines much more thermally sensitive reactivity than you have before. Did you need to change your control system at all? I hate to ask a yes or no question,

but it's not identified here. The question is does your control system need to change because of the reactivity associated with going to the higher enrichment fuel? Your moderator temperature coefficient has increased by about 50 percent.

MR. HALE: Certainly, there are changes to the control system itself. You're talking about level control?

MEMBER SKILLMAN: No, I'm talking about the reactivity that comes because you've got a hotter core. Your moderator temperature coefficient has become more reactive, right? Maybe we'll talk about this in the fuel section, but there is a relationship between the control system and how much positive reactivity you had when you add colder water because you're dropping temperature and you're adding reactivity, which would make the plant more sensitive to cold water injection. My question is have you considered that in your control system? And if so, how has the control system changed?

MR. HALE: Which control system are you speaking?

MEMBER SKILLMAN: Well, most would call it the RCS, the reactor control system --

MR. HALE: Control rods?

MEMBER SKILLMAN: It's the reactivity component into your control rod drive control system.

MR. O'FARRILL: Well, I know we did not make any changes to the automatic rod control system.

MEMBER SIEBER: Do you actually operate in automatic?

MR. SHAFER: Yes. The control rods are operating in automatic. We do take it to manual when we maneuver the plant, but automatic is normal steady state ops.

MEMBER SIEBER: Does your plant cycle?

MR. SHAFER: No, sir, it does not cycle.

MEMBER SIEBER: Base load --

MR. SHAFER: Base load; that's correct, sir.

MEMBER SIEBER: And so it doesn't really, nothing changes, whether you're in automatic or manual?

MR. SHAFER: That's correct.

MEMBER SIEBER: You just sit there for a year.

MR. HALE: But certainly the safety analysis takes into account, you know, moderator temperature coefficient effects and things of that sort in terms of return to power for accidents, like

steam line break or whatever events that you have. And I believe at Turkey Point, for steam line break, we have about a 13 percent return to power. But, you know, so those effects are accommodated in the safety analysis and addressed, the colder temperatures, moderator temperature coefficient effects, and that sort of thing, both from a D&D and a plant performance standpoint.

MEMBER SIEBER: Through all the changes you've made over the years, T-ave, though, is dropping, right? According to your slide --

MR. HALE: Well, you have to, we certainly operate at the high end of the T-ave. Westinghouse evaluates a range, you know, because when you embark on the safety analysis you want to make sure you accommodate any change you may make in the future.

MEMBER SIEBER: Yes. When I look at that, though, I look at what T-h is going to be because of Inconel issues. Yours is not the highest I've seen.

MR. HALE: Right. If you look at the four-loop plants for example, like at Seabrook --

MEMBER SIEBER: Sometimes plants --

MR. HALE: -- you're at 619 or 620. So we're well within the range of experience, operating experience in terms of Inconel but --

MEMBER ABDEL-KHALIK: To follow up on Mr. Skillman's question, how much has your end-of-cycle moderator temperature coefficient changed?

MR. O'FARRILL: The tech spec change, I believe, that we are proposing is going to 41.

MEMBER ABDEL-KHALIK: Forty-one? Minus 41 PCM per degree?

MR. O'FARRILL: Right.

MEMBER ABDEL-KHALIK: And what was it originally?

MR. HALE: I think it's 35.

MEMBER ABDEL-KHALIK: Thirty-five?

MR. HALE: Yes, 35.

MEMBER SKILLMAN: Excuse me. My take-away is that your control system reactivity component has not been modified to accommodate the increase in moderator temperature coefficient reactivity and that your analysis have demonstrated that the plant is able to navigate through reductions in reactor coolant system temperature, wherever they may come from.

MR. O'FARRILL: That is true. And it's worth to note that our automatic rod withdrawal has been defeated. We do not have that in our system, so it only controls to insert rods automatically.

MR. HALE: So looking at the power

mismatch circuitry, looking at a turbine load, and looking at T-ave, T-reference is all the inputs into our rod control system, so if we do have the more sensitivity of temperature effect, it will definitely be responsive to that. Now, the internals of rod controls, to the best of my knowledge, we haven't done any changes to that.

MEMBER SKILLMAN: Thank you.

CONSULTANT WALLIS: Is this -- going back to the slide that talks about the LEFM system, how do you install -- does it come as a flange, everything's together?

MR. HALE: Yes. It's a spooled piece, basically.

CONSULTANT WALLIS: It comes as a spooled piece. So you have a bunch of pipe, and you have to put flanges in.

MR. HALE: Yes, it's actually welded in.

CONSULTANT WALLIS: You're looking at this with very great accuracy. You have to worry about the real accuracy with which you install it, too.

MR. HALE: That is true.

CONSULTANT WALLIS: Is this all controlled by Cameron, is it?

MR. HALE: They established installation

requirements, and you're required to meet those and verify that you meet those.

CONSULTANT WALLIS: The gaps in the flange and all that stuff is very well controlled so --

MR. HALE: It's not flange. It's actually welded in.

CONSULTANT WALLIS: It's actually welded in.

MR. HALE: Yes.

CONSULTANT WALLIS: So whether you finish the welds -- I mean, anything you do can slightly change that flow, which will get you 0.31 percent instead of 0.3 percent.

MR. ZIELONKA: Andy Zielonka from Florida Power and Light. You got the minus ten inches from what it was tested at the lab, and we specifically paid very close attention to achieve that during the installation. It's very close. It's ten inches, that's it, plus or minus.

CONSULTANT WALLIS: Ten inches in what?

MR. ZIELONKA: Excuse me? Oh, within ten inches of the tested configuration, so when you put it --

CONSULTANT WALLIS: In the pipe, placed in the pipe --

MR. ZIELONKA: -- mentioned before, the whole assembly was tested as it is in the field, and you have to, in the field, install it within plus or minus ten inches of the tested configuration in the lab, and we specifically paid attention to that during installation.

CONSULTANT WALLIS: And the welds on the inside have to be really finished so that you don't produce any roughnesses or turbulence or something.

MEMBER ABDEL-KHALIK: On the change in the main steam safety valve setpoints, historically have your safety valves passed the test for --

MR. HALE: Yes.

MEMBER ABDEL-KHALIK: You haven't had any stuck valves that would open at a higher setpoint or anything of that sort?

MR. HALE: I'm not sure what the historical performance has been. Typically, they've been very good. We pop test them at the, you know, full pressure.

MR. SHAFER: That's correct. In my recollection, we've only had maybe one problem. Rich Tucker might be able to help me out with that one. I think there was only one problem we've had with the safety valve, which we were close to at the beginning

of an outage. We did have to enter into the action statement for that.

MR. TUCKER: Rich Tucker, FPL operations also. I don't know the total number of failures, but it's been within the program. We have a valve program that determines the testing population and whatnot. So we've had a few failures, but it's within the program.

MEMBER ABDEL-KHALIK: Can we get more information on that, the frequency of failures as far as passing the setpoint tests?

MR. HALE: Absolutely, sir.

CONSULTANT WALLIS: So this is a three-loop plant?

MR. SHAFER: Yes.

CONSULTANT WALLIS: How much does the loop flow rates vary? Do they move around? Are they consistent, or do they vary among themselves or with time and all that?

MR. SHAFER: I'm not sure --

CONSULTANT WALLIS: It gives me a little feeling for uncertainty. I mean, if you're looking for this very accurate measurement --

MR. SHAFER: You're talking feedwater flow?

CONSULTANT WALLIS: Yes. Feed water flow.

MR. O'FARRILL: This is Carl O'Farrill. You're asking about the MUR for --

CONSULTANT WALLIS: Yes, that's right.

MR. SHAFER: This is the -- the LEFM is installed on the feedwater.

CONSULTANT WALLIS: That's right, that's right. But does it vary?

MR. SHAFER: Typically, feedwater is controlled to maintain steam generator level --

CONSULTANT WALLIS: It varies a lot, though.

MR. SHAFER: I don't know. It's fairly -- to maybe make sure that I understand the question correctly --

CONSULTANT WALLIS: You have some sort of output on the feedwater flow with time and stuff like that.

MR. SHAFER: That is correct. Normally, it's pretty consistent. As a matter of fact, we did some upgrades --

CONSULTANT WALLIS: Do you figure around one percent or --

MR. SHAFER: I would say less than one percent. We average about 3.3 times ten to the six

mass per hour steam flow, and from the recorders I would say it's less than one percent oscillation. Now, feeding into the venturi system, which feeds into the calorimetric --

CONSULTANT WALLIS: You have three different loops, right? So you have three feedwater flows.

MR. SHAFER: That is correct, sir.

CONSULTANT WALLIS: And are they consistent with each other?

MR. SHAFER: Yes. They're pretty much consistent with each other.

CONSULTANT WALLIS: Within this 0.3 percent?

MR. SHAFER: To the best of my knowledge, that is correct, sir.

CONSULTANT WALLIS: So you have some kind of way of looking at this, some reason to suspect that you're not getting 0.3 percent? I mean, if one of them is doing something different from the other ones, you might say, well, wait a minute, are we really measuring that right? Because this 0.3 percent is a very accurate claim.

MR. SHAFER: Right. The current venturi system that we do use, the I&C does quarterly

calorimetric calibrations. They'll go in there and verify if there's any deviations to the loops. Also, when we perform our calorimetric report, the computer will spit out if we have an offset or if we have any kind of a deviation from normal. It will bring it out for us and it will force us into performing a manual calorimetric versus you rely on the computer inputs.

MR. HALE: The LEFM device itself also has self-checking mechanisms. If there's changes in flow profile, things of that, it will alarm, and you have to take specific actions as a result of that.

MEMBER ABDEL-KHALIK: Back to the end-of-cycle moderator temperature coefficient, is the minus 41 PCM per degree within the sort of experience range for other plants?

MR. O'FARRILL: It is in that range. I believe at Seabrook we have something that low in moderator temperature. I can go back and check and see from that standpoint or we can ask Westinghouse whether they have that experience in the other --

MEMBER ABDEL-KHALIK: I think if they can answer it now, that would be great.

MR. O'FARRILL: I don't think they have that answer with them right now.

MEMBER ABDEL-KHALIK: Okay. Is there any

way to follow up?

MR. O'FARRILL: Yes, we will follow up.

MEMBER ABDEL-KHALIK: Thank you.

MR. HALE: Okay. Moving on to the specific modifications we're making to attain the power level, we are replacing the high-pressure turbine. One of the reliability improvements we're implementing is we're installing electrohydraulic system, Turkey Point's turbine control system. We did not have a hydraulic system. We actually used lube oil as part of our control system on the valves, so this is a significant upgrade. We're going with digital turbine controls. We are replacing the moisture separator re-heaters due to capacity, as well as maintenance issues. Condensated feedwater --

CONSULTANT WALLIS: Where are those, and what kind of steel are they made out of?

MR. HALE: They're made out of carbon steel.

CONSULTANT WALLIS: They are? So they do have wear?

MR. HALE: Yes, they do have wear, and we inspect them regularly and evaluate them. But the primary reason we're replacing them is for capacity.

CONSULTANT WALLIS: You're going to

replace them with carbon steel?

MR. HALE: Well, for the high-wear areas, we'll be looking at better materials in terms of erosion, that sort of thing.

MEMBER SKILLMAN: Now, for the steam path, you're replacing your turbine and your MSRs. There's some very potent piping between your regulator valves and your HP turbine and from your turbine exhaust into the MSRs back into your LP turbine. Could you explain to us what inspections you've performed to confirm that the piping that you're not replacing is fit for duty?

MR. HALE: Yes, there's quite a bit of that piping. Of course, the main steam piping is not, you know, is not required to be looked at from a FAC standpoint. Typically, our performance has been very good with the main steam piping from the steam generators to the high-pressure turbine to the MSRs. Certainly, the extraction piping has had a long history with regards to erosion, corrosion, that sort of thing. As part of our FAC program, we inspect it regularly. There's quite a bit of the piping we've replaced with chrome-moly through the years.

So our FAC program is very mature. It's a good program. We follow the CHECWORKS. It's

updated and tweaked regularly as a result of actual performance. So we've used all that intelligence and knowledge to evaluate, you know, capability of existing piping. Certainly, we'll continue to monitor it the way we do now in terms of our FAC program, and we've made adjustments based on the increases in flow and that sort of thing. And we'll do some additional baseline inspections, as well as ongoing inspections in terms of ensuring that we're monitoring, you know, piping erosion appropriately.

MEMBER SKILLMAN: Thank you.

MR. ZIELONKA: Just to add -- this is Andy Zielonka. What Steve mentioned, back to main steam, we've actually performed a measurement of flow-accelerated corrosion measurements. There's very little to no wear in that piping. We've also taken a measure of moisture carryover tests here recently, which shows that our moisture carryover is very, very low. We have replaced the most susceptible piping in the system, which is the number six extraction to the high-pressure feedwater heats with chrome-moly piping. We have performed corrosion inspection in the feedwater lines also, such as in the feedwater piping. We've done measurements here recently to confirm that we won't have any issues going up to the higher flows.

And, of course, all this information is going into the flow-accelerator corrosion program based on the new flows and pressures and so forth with continued monitoring. So we have a very, very good program to monitor all of the health of the piping in the systems.

MEMBER SKILLMAN: Thank you.

MEMBER ABDEL-KHALIK: Historically, have you had any problems with either the main or bypass feedwater control valves?

MR. HALE: Historically, we haven't.

MEMBER ABDEL-KHALIK: Including the controllers?

MR. HALE: Including the controllers. They've been, you know, good performing historically. We haven't had any real issues there. The modifications we're implementing are simply replacing the actuators and the internal trim on the main feedwater valves.

MEMBER SIEBER: Are you just going to put the same kind of trim in, or are you modifying the trim to the main feed valves?

MR. HALE: We're modifying the trim for, you know, to ensure that we're operating at the right position in the control valve, you know --

MEMBER SIEBER: So you're trying to make it linear?

MR. HALE: Yes. Well, no, you want to make sure you're operating with the valve approximately, you know, between 70 and 80 percent. You want to be in the good control band, and modifying the trim will allow us. If we hadn't, we would have been operating well above that normal operating range.

MEMBER SIEBER: And three PWRs, feedwater control valves in the past have been an issue for some plants. Were they an issue for Turkey Point in its early days as far as stability and responsiveness?

MR. HALE: You know, being at Turkey Point for all the years that I've been there, certainly the challenges are at low power operation, you know, where you're in manual control and ensuring that you're maintaining, so that's where the challenge is. Once you reach 100-percent power, you know, everything is flat and runs pretty well.

MEMBER SIEBER: I think the problems with most plants of your style and vintage is in the power range for the valves were very sensitive because of the trim design, which is not a good condition. You haven't experienced that, I presume.

MR. HALE: No --

MR. SHAFER: No, not at the 30-percent area. The low power, as you mentioned earlier, with some of the challenges, we do have manual. We don't have automatic bypass feed reg valves, so that is a little bit challenging.

MEMBER SIEBER: Thank you.

MR. HALE: In the condensate and feedwater system, certainly one of the major modifications we're implementing, we are replacing the main components of the main condensers. We're replacing the condensate pumps and motors. We talked about the control valves. The feed pumps, we're actually replacing the main rotating assemblies. The current motors are adequate for flow capacity we're looking for. We are replacing the high-pressure feedwater heaters.

CONSULTANT WALLIS: And the main condensers, that's the whole thing, or is it --

MR. HALE: The main, you know, tube sheets, tubes, water boxes.

CONSULTANT WALLIS: Of the whole thing?

MR. HALE: No, you really -- but the primary components we're replacing: the tubes, tube sheets, and water boxes.

MEMBER SIEBER: What material will you use in the new condenser tubes?

MR. HALE: Well, our current tubes are titanium, and so we're replacing them with the same types of materials.

MEMBER SIEBER: Titanium?

MR. HALE: Yes.

MEMBER SIEBER: Have you had any problem -- were they originally titanium?

MR. HALE: They were not originally titanium. When we instituted the, you know, removing the copper in the systems when we replaced the steam generators, we replaced the condensers with titanium.

MEMBER SIEBER: Did you have problems -- titanium has a different strength and vibrational characteristics than copper or stainless, and usually the remedy in the original design is to change the position of the tubes. Have you had any of those vibration issues because of the titanium tubes are lighter than the --

MR. HALE: Yes. Originally, by design, you try to accommodate that with wall thickness of the titanium, but we --

MEMBER SIEBER: So you have bigger walls?

MR. HALE: Yes, but we have had some vibration. We have stakes and tubes in the upper portions of the condenser.

MEMBER SIEBER: Okay.

MR. HALE: One of the issues we've had in our tubes is our, we had issues with the cathodic protection system where it actually was hurting the tubes, rather than helping the tubes.

MEMBER SIEBER: Okay.

MR. HALE: And so we've had some tube performance issues. We've had tube support plate, I mean not tube support but tube sheet where you had leakage around the tube connections. And also the water boxes have, you know, have been patched quite often and need to be replaced.

MEMBER SIEBER: Now, one of the issues in condensers for this type of unit is where things like re-circulation lines come back into the water box used either as a baffle plate to shield the tubes from the impingement of this --

MR. HALE: Right.

MEMBER SIEBER: -- high-pressured jet. Have you checked, modified, or have any experience with failures of those and --

MR. HALE: I've had personal experience. I've been in the condensers -- yes, yes. Typically, a lot of the steel, you know, we usually do condenser inspections as part of our normal outage.

MEMBER SIEBER: And you always, sometimes a condenser inspection does not inspect every tube.

MR. HALE: Right.

MEMBER SIEBER: You always, I hope, inspect the ones around where the baffle plates are --

MR. HALE: Oh, yes.

MEMBER SIEBER: -- and across the top, right?

MR. HALE: Yes, yes.

MEMBER SIEBER: All right.

MR. HALE: And, certainly, being a salt water site, it's critical that we keep a tight condenser.

MEMBER SIEBER: Yes, right.

MR. SHAFER: This is Sam Shafer, Florida Power and Light. A few years ago, we did have, one of the sparger nozzles did break off and impinged on the tube, which we had to remove the unit from service. And from there, we did have to come up with a beefier design for the sparger nozzles inside the condenser. We haven't had many challenges after that.

MEMBER SIEBER: Okay. That's happened at other plants, also. Okay, thanks.

MR. HALE: We can move on to the next slide. In the heater drain system, we're also

modifying heater drain piping, and we're also installing upgraded control valves and digital controls there. Certainly, there's a number of BOP plant setpoints that are changing and also beefing up some of our BOP piping supports, depending on the system. We are replacing our turbine plant cooling water heat exchangers, these are, you know, kind of like the component cooling water for the turbine plant, to provide additional cooling capacity for the secondary side and also improving the heat removal around the control rod drives with new fan motors and coolers.

On the electrical side, we're doing some extensive modifications there, as well. We're actually replacing the rotating element, as well as rewinding the generator. Included with that will be new current transformers, hydrogen coolers, exciter air coolers, iso-phase bus modifications. You know, certainly, this is an OE item that's been out there. We want to ensure that we have adequate cooling for the iso-phase bus.

Main step-up transformers, we have replaced those, but we want to, as a result of additional capacity, we're providing additional cooling. We are replacing the unit auxiliary

transformers, as well, and then implemented switchyard modifications.

MEMBER ABDEL-KHALIK: Again, historically, any issues with the generator leaks?

MR. HALE: We have had leaks in the past where you have to look at, you know, external leaks, but nothing --

MR. SHAFER: We do have leaks on both main generators. We are looking at the replacement of some lead boxes to minimize that leak. From the calculations, 500 scfm is going to be the most acceptable value, but we do have one unit that's over that value right now so --

MEMBER ABDEL-KHALIK: How much over?

MR. SHAFER: It's 957, I believe, scfm is currently what we're measuring. We do have contingency plans and actions in place. The Control Room is briefed to take actions if we need to if that number increases. We are noticing it's very temperature-sensitive, contraction expansion of the actual generator, so we are mitigating that. But with the upcoming outage here in 45 days, they will be replacing. We've already identified where it's leaking from, so that will be replaced during this overhaul.

CONSULTANT WALLIS: This is pretty well a new generator?

MR. HALE: Essentially, yes.

MEMBER SIEBER: Is your turbine generator in a building?

MR. HALE: No, sir.

MEMBER SIEBER: I didn't think so. My --

MR. HALE: Outside plant.

MEMBER SIEBER: It's been a while since I've been to your plant, but I remember it sort of being an outside type.

MR. HALE: Yes, sir.

CHAIR SHACK: Ventilation is not a problem.

MR. HALE: Ventilation is not a problem.

MEMBER ABDEL-KHALIK: And the elevated hydrogen leak has been going on for how long?

MR. SHAFER: If I'm not mistaken, it's been cycling right around two refueling cycles. It's been varying up and down. We have gone in and put in what we call VIP to mitigate some of the leakages. The ones, the last remaining part that we're attributing the majority of the leakage is from this lead box or connection box which is under the belly of the generator, and that's what we're waiting for this

EPU to pull it out so we can do the mitigation for it.

MEMBER ABDEL-KHALIK: Okay, thanks.

MR. TUCKER: This is Rich Tucker, FPL operations. The leak rate that was stated is per day. That's the cubic feet per day. And the generator uprate Steve mentioned is intended to specifically address the major leakage path in the generator.

MR. HALE: Any other questions on modifications and the approach we took?

MEMBER SKILLMAN: Yes. Let's talk a little bit about the reactor coolant system. You raised T-ave about three degrees and T-hot about 14. What evaluation did you give to your code safety valves and your PORV and the resultant impact on the pressure relieve tank for that change in overall enthalpy to the reactor coolant system?

MR. HALE: There's a number of events and evaluations that we have to make in terms of over-pressure, you know, to establish the capability of a system, both the PORV and the safety valves, to accommodate the changes. And there's actually a specific evaluation that's done for the pressurizer relieve tank, as well, to ensure that it can accommodate the changes as a result of the uprate.

MEMBER SKILLMAN: The staff seems to

indicate that that, that the tank and the valving is sufficient for the changes in the reactor coolant system because the PRT is really based on the pressurizer steam volume. I guess my question is isn't there a very important effect on how the pressurizer behaves based on the enthalpy of the water that's contained in the loops lying below the pressurizer? Perhaps, you would say that has been accommodated in analysis. I'd be interested in more details around that. You actually have a hotter reactor coolant system of the same volume that it's mass has changed, the temperature has changed. So I'd be curious as to whether or not the orifice-ing in your safety valves and your PORV have been demonstrated adequate for the change in the heat that is now contained in your hotter core and in your hotter reactor coolant system, including the metal.

MR. HALE: Well, you know, certainly, there are specific analyses that look at over-pressure events and the capability of the system to accommodate those over-pressure events, which includes addressing the changes in enthalpy in the reactor coolant system, as well as capacity of the valves and whether they're adequate or not. We will get into talking about, in Carl's piece we'll talk about the over-pressure events

that were evaluated and the results of those.

MEMBER SKILLMAN: Thank you.

MEMBER ABDEL-KHALIK: So your peak pressure for a loss of feedwater ATWS hasn't changed?

MR. HALE: I didn't say it didn't change. It did change, but we're still within the design limits of the system.

MEMBER ABDEL-KHALIK: Are you going to talk about that?

MR. O'FARRILL: It will be part of the presentation. We'll have those results presented.

MEMBER ABDEL-KHALIK: Okay.

MR. HALE: It will be in the section that Carl will speak to. Any other questions on modifications? Okay. With that, I'll turn it over to Sam, who's going to talk about power ascension testing.

MR. SHAFER: Again, my name is Sam Shafer, and I'm assistant operations manager for the Turkey Point station. I'm also a licensed SRO. And I apologize. My name tag fell down there. I'll be grabbing that during the break. Sorry about that.

The topic that I'll be covering, of course, is the power ascension testing. We'll be looking at, specifically, our preparation phase, the

approach of it, and the actual test plan. We'll be talking about some acceptance criteria here also.

So the test objectives that we developed, we were looking for the satisfactory performance of the equipment that we were going to be installing, as Steve was talking about. A major balance of plant equipment is going to be putting into the systems, ensuring that the integrated plant response also will be closely monitored at each phase of the power ascension. Also, look at a careful monitored approach for our new extended power level that would be going there would be controlled and deliberate as we increase power. Making sure that we meet all our expected established requirements.

We're looking at the roles and responsibilities to make sure that they're clearly documented and clearly understood. We were using the guidance from the Reg Guide 1.68 and also looking at the NUREG-0800 criteria to make sure that we're well within the testing programs. The test plan and actual implementation test procedures that will govern for the power ascension, we made sure that those are also laid out very specifically in how we're going to be implementing that.

Incorporating the industry benchmarks for

OE. We have a great advantage here at Turkey Point. Point Beach is part of our fleet which just went through their uprate, and we sent one of our most senior reactor operators to the Point Beach power plant during their power ascension. So he was able to bring back live OE for us to make sure that we incorporate and capture that into our test plan in development.

We also contacted INPO. They were very instrumental in helping us to identify with all the other utilities that went through either the stretch power or extended power to make sure we grab all that OE. We filtered it down and made sure that each one of the specific areas that we're going to be doing, that we capture that and make sure it's included in our test to make sure in post-modification testing and power ascension testing that we got it completely covered.

CONSULTANT WALLIS: Did you install, are you going to install any instrumentation to monitor new things that isn't installed now, like flow-induced vibrations for instance? Are you going to install any instrumentation?

MR. SHAFER: Yes. Right now, just as an example, there will be like 60 RTDs looking all over

the feedwater secondary side, looking at putting ultrasonic flow measuring devices, be installing recorders with duotron-type devices to measure their frequency of change of the flow, any kind of flow changes that we're looking at, looking at capturing recorders for level changes on the feedwater system. So, yes, there will be multiple --

CONSULTANT WALLIS: Are you looking at vibrations of things?

MR. SHAFER: Vibration and the thermal expansion will also be looked at.

CONSULTANT WALLIS: How steam flows in the steam generator? Are you going to look at the steam generator tubes, or is that done by analysis?

MR. SHAFER: As far as steam generator in tubes? Yes, we're going to talk about that.

CONSULTANT WALLIS: You'll talk about that later?

MR. SHAFER: Yes, we figured we would --

CONSULTANT WALLIS: It's done by analysis, isn't it?

MR. SHAFER: Yes, yes.

MR. HALE: And, hopefully, we incorporated all the dialogue we had at Point Beach to address the question. So I'll speak to that specifically.

MEMBER SKILLMAN: As far as OE is concerned, what would be an example of an a-ha item from the OE where you would say, boy, are we glad we found that piece of information? What was unusual or different that the OE brought to what you're going to do at Turkey Point, please?

MR. SHAFER: One example of the OE that we used is going to probably be the digital EHC system for the turbine. It's pretty much boilerplate across the industry on how people have implemented the turbine controls. We had an individual, a reactor operator as part of our power ascension test team. He actually used to work at Waterford 3, and he was working in the I&C department and set up their actual EHC. So the lessons learned that he had we incorporated into ours and the graphics display to make it more operator friendly, to make sure its usability and the actual controls, how to switch over from the turbine input pressure over to the automatic megawatt and how it's all laid out is much more user friendly for Turkey Point now. So that's one benefit that we got from OE.

MEMBER SKILLMAN: Thank you.

MR. SHAFER: Next slide. Okay. We'll continue with the approach. The expected values for

each data set has been determined by engineering. Baseline data will be taken at each of the plateaus, and I'll cover the plateaus here in a minute. Of course, for the expected value, the modeling is based upon our secondary heat balances that was calculated, also comparing it with the hydraulic models from the condensate feed in the heater drain system. So all those would be put together to give us the expected values, so those baselines will be taking the actual values, comparing it to the expected values, and we'll move on from there.

Master test plan is coordinating to normal operating procedures that we currently have. Now, that's a big benefit. That's also a good insight we received from Point Beach, using one test procedure. So the reactor operators currently have a normal power ascension, like we always have. It's called the general operating procedure. Using that procedure and giving an example, like a specific point, 20-percent power, in our general operating procedure there will be a whole point or a kickout to go to the master test procedure to perform all the testing we need at 20 percent, make sure it's completely satisfied, all acceptance criteria is met. Then it brings you back into the general operating procedure prior to

continuing on to the next plateau. So that was a lesson learned from Point Beach, and we've incorporated that and we're hoping for great expectations with that.

Test reports will be generated for each one of our power plateaus. Currently, based upon the modeling that we've done, no large plant transient testing will be performed. Using analytical methods and training facilities, we were adequately able to simulate the large transient type events. LOFTRAN, of course, is the code that we evaluated the large operational plant transients. It has been benchmarked against data of several other plant transients. Operators will be trained on these large transient events with a simulator. Once we get to the simulator we upgraded, they will be trained on the simulator with it.

Following the test methods, scope, and approach from other successful plants that have already uprated their units, we'll be using theirs as a benchmark. And we got the OE from Point Beach, Ginna, Beaver Valley, just to mention a few.

Next slide. Some of the testing plateaus will include, we've got pre-operational test procedures at each one of these plateaus. They have

to be started and completed prior to continuing and part of that data collection, the pipe vibrations, looking at thermal expansion, radiation monitoring, balance of plant data collection, nuclear NSSS primary data collection also, control system stability, dynamic tuning, data analysis, and test review board, and also a plant safety committee to review and approve the test reports.

Looking at the, for instance, like the control system for stability and the dynamic tuning, we basically looked at one of the smart transmitters that we have installed all over the plant. We're making sure that the initial settings are all incorporated and verified prior to actually starting up the unit. And part of the dynamic testing we'll be doing is validating those projections and predictions that they provided for us.

What we provided here is just an overall test plan of what specific plateaus that we're going to be looking at. The color code, you're going to notice the yellow at 87 percent, which is equivalent to my current licensing 100-percent value. So from 87 percent on up is the extended power. So these are the specific tests that we will be performing.

MEMBER ABDEL-KHALIK: Now, historically,

as far as physics testing is concerned, particularly the ITC, the isothermal temperature coefficient, do you measure that at sub-critical conditions or do you measure it at critical conditions because --

MR. SHAFER: Critical conditions.

MEMBER ABDEL-KHALIK: Because you're limited in the number of counts so you have to do it at critical conditions?

MR. SHAFER: I'm not sure. Normally, we perform it during our start-up testing. We dilute to critical, and then we perform all the testing for the physics testing. So the specifics on why for ITC --

MEMBER ABDEL-KHALIK: Right. Why do you do it at critical conditions?

MR. SHAFER: I don't have that readily with me.

MEMBER ABDEL-KHALIK: Have you always passed the physics testing?

MR. SHAFER: Yes, we've always passed our physics testing. Now, in this particular case, because of the uprate, I'll give you an example. Normally, the physics testing could run anywhere from 16 to 24 hours. The physics testing will be performed here will be approximately a total of five to seven days, looking at each specific core parameter changes

that we're looking at. So there will be a significant difference in how we do the start-up phase of the unit. Any questions on the actual test plan?

MEMBER SKILLMAN: Yes. I'd be curious why you are going to get a benchmark. This plant radiation survey that's about seven or eight from the bottom, you're going to keep a benchmark at your current 100-percent power that is 87 percent on your chart there, and then you might check again or you will check again when you're really at 17 or 18 percent down the road. So it would seem to me that, as mundane as that survey might be, that might be one that you want to do fairly often.

MR. SHAFER: There is going to be continuous monitoring by our radiation protection department. These criteria are the specific ones that have to be done, but there will be continuous monitor all the way up in our power ascension. That specific one for the 87 percent was because we have very good historical data up through our 100-percent value for any kind of changing of rad exposures. So specifically over 87 is where they wanted to do the monitoring, but the actual power ascension, RP will be out looking for changes all over our auxiliary building.

MEMBER SKILLMAN: Let's look at one more. I want to go back to Dr. Khalik's question early on about AOA, axial offset anomaly. What imbalance do you normally run on a core at this plant approximately?

MR. SHAFER: Usually, I'll be running about a minus two that I would see beginning of life up to maybe 0.5 positive or a 1 positive at the end of life.

MEMBER SKILLMAN: Thank you. Okay, thanks.

MR. SHAFER: Any other questions on the test plan? Okay. The acceptance criteria and actions established for the testing. Again, looking at the guidance from the NUREG-0800 and the Reg Guide 1.68, Level 1, which is the acceptance criteria, those are associated with the risk-significant or safety-significant type components. If we don't meet a Level 1 criteria, we will make sure that we secure the testing, reduce the power to the last known safe condition, initiate evaluation of the condition, retest only once the condition has been corrected, document problem and resolution, and obtain the plant safety committee review prior to continuing with the power ascension.

MEMBER SKILLMAN: Now, are the Level 1's the ones that are shown on Slide 20 or the Slide 20 tests Level 1's and Level 2's?

MR. SHAFER: Those are both Level 1's and Level 2's, sir.

MEMBER SKILLMAN: So how would we generally know which ones are Level 1 and Level 2 versus Level 2?

MR. SHAFER: Level 1 example would be challenging a tech spec, an RCS flow of 270,000 gallons per minute, versus condenser water box, when we do condenser monitoring, the water box vacuum of less than 16 inches. So safety significance versus the non-safety is the Level 1/Level 2. So the test plan incorporates the scope of the actual power ascension and in there both there's Level 1 and Level 2 type criteria.

MEMBER SKILLMAN: Okay, thank you.

MR. SHAFER: You're welcome, sir. Next slide. Okay. Level two, of course, is the functional criteria. Those are associated with design type limits. On these particular criterion, if they're not, we will definitely stop the testing. We may or may not have to reduce the power. It's dependent upon what the issue is. For instance, if it's low vacuum,

as we described earlier, we wouldn't probably have to reduce power. We'd just have to go figure out what's causing us not to attain the vacuum that we expect. So in those type cases, it could be something where, yes, we do need to reduce power because we don't understand what's going on with the parameters that was given to us.

SROs will be our test directors. Those will be active SROs, be in the control room monitoring the power ascension. So at any time we feel that we need to reduce power, it's well within their authority to reduce power back to its known stable condition.

MEMBER SKILLMAN: Who's in charge?

MR. SHAFER: For the -- the actual shift manager is the actual command and control for our control room. The lead test engineer with the SRO on the test team will be maneuvering the plant with a shift manager in direct oversight.

MEMBER SKILLMAN: Is the shift manager's role endorsed by the station executive management and by the company's executive management?

MR. SHAFER: Yes, absolutely.

MEMBER SKILLMAN: So that guy can say stop here?

MR. SHAFER: Absolutely.

MEMBER SKILLMAN: And he's not going to get cracked in his performance appraisal or his raise?

MR. SHAFER: That is correct, sir.

MEMBER SKILLMAN: Thank you.

CONSULTANT WALLIS: Do you make these changes during the day or at night?

MR. SHAFER: Twenty-four hours, sir.

CONSULTANT WALLIS: So some of them could be at night?

MR. SHAFER: That's correct. Give you an example, I will be one of the test leads. We're still determining if I'm going to be on night shift or day shift, but I will be one of them. Rich Tucker, another one of our SROs, will also be part of this test team. So there's -- right now, I've got four senior reactor operators associated with the test team. I have one reactor operator, and I'll have about, a total of about six reactor operators when we're complete and about ten non-licensed operators for this test team.

CHAIR SHACK: I would point out we have about a half an hour to go, and we're about halfway through the slides and there's a fair amount of substance to go so . . .

MEMBER SKILLMAN: Let me ask this, please.

Setting your watch, and then setting your watch again, and setting your watch again as you're bringing the plant up. Will it be your intention to have your tech support staff or your tech support center or some additional engineering resource available to you while you are going through this?

MR. SHAFER: Yes, sir, absolutely. As a matter of fact, part of the power ascension test program that we're developing, there is a separate entire entity that's an engineering support staff that will be working with the contract engineering group and in-house engineering group, working with the test team as power is ascending.

MEMBER SKILLMAN: Now, are these individuals standing watch --

MR. SHAFER: No, sir --

MEMBER SKILLMAN: -- all through the night, or are these your day personnel?

MR. SHAFER: I'm sorry, sir. The support team will be assigned days and nights, but they're not standing watch on the unit.

MEMBER SKILLMAN: I see. So they're support teams, they go on 24/7, but they're relieving each other as you would in the control room with your operations --

MR. SHAFER: Yes, sir, that is correct.

MEMBER SKILLMAN: Thank you. Thank you.

MR. SHAFER: You're welcome.

MEMBER ABDEL-KHALIK: Who serves on the test review board?

MR. SHAFER: That will be one of the senior SROs at the station. Myself included would be one of them and also the operations manager.

MEMBER ABDEL-KHALIK: And how would these people know that non-compliance with a design expectation may or may not affect a safety limit?

MR. SHAFER: When they initially developed each one of the criterions for either Level 1 or Level 2, those have been vented out using the appropriate review process that was generated by the engineering group. So when we do the review of it, not only its operations, we will have an independent, it will be a lead engineering manager type level that will also, when we review the test reports, it has to get through us and then independently verified with our engineering team.

MEMBER ABDEL-KHALIK: So engineering is a part of that test review board?

MR. SHAFER: That is correct.

MR. HALE: Rich, did you want to say --

MR. TUCKER: Yes, this is Rich Tucker, FPL operations. Just one thing I would add to what Sam has said is that this entire evolution will be treated as an infrequently performed evolution with the management designee and test director and that type of oversight.

MR. SHAFER: Correct. Any other questions? That concludes the power ascension portion.

MEMBER SKILLMAN: Okay.

MEMBER SIEBER: Since we're getting ready for a break and I've looked at the agenda and looked at your handouts and looked at the SER, perhaps some place along the line somebody will address the fact that your upper shelf energy for the reactor vessel embrittlement will go below 50 foot-pounds, which is the regulatory limit. And the SER says that you have compensated for that by extra calculations, but I notice no place on the agenda or in your slides or in anybody's slides that I have that that's even discussed. And it doesn't make any difference to me who discusses it. Perhaps the staff, since they accepted what you did, may want to discuss it. But there is a hand calculation that can be made to justify an upper shelf energy that's less than 50

foot-pounds, and I'd like to hear a little bit about it. And I thought before we have the break I would say something about it, so you have a little bit of break time to figure out how you will answer that question, whether it's the staff or the applicant.

MR. HALE: Okay.

MEMBER ARMIJO: I would like to join him. Another issue in the materials there, it's limited to steam generators. I'd like to have some discussion, you may want to think about it, about the core internals and the influence of the power uprate on susceptibility to stress-corrosion cracking of your upper core plate and why you believe that there is no significant increase in risk for this type of cracking due to the power uprate.

MR. HALE: This is a radiation-assisted stress-corrosion cracking?

MEMBER ARMIJO: Yes, IASCC and then also all the SCCs, IGSCC, PWSCC.

MR. HALE: You know, as part of license renewal, we had to develop an internal inspection program as part of our aging management program for the reactor vessel internals. You know, we've looked at, there's a threshold for IGSCC, radiation-assisted stress-corrosion cracking. We do have Rudy Gil here,

who is our materials person. Rudy, do you want to mention something about, you know, internals inspection programs and what we're doing there?

MR. GIL: Yes. Actually, as part of license renewal -- this is Rudy Gil, engineering at FPL. As part of our licensing renewal effort and, of course, as part of the industry initiative on reactor vessel internals, we are going to be following the EPRI document MRP-227 that has actually recently been approved by SER issued by the NRC. And so those inspections will be taking place, and I can get back to you on the exact dates but it will be shortly after the EPU uprates are completed that we will implement those. We are in the process of finalizing all of the acceptance criteria, working with Westinghouse for all of the components, and of course have modified our program to implement and incorporate the conditions that have been put on the MRP document by the staff.

CHAIR SHACK: I was curious. The licensing, the application itself doesn't mention MRP-227 anywhere. You refer back to some much earlier Westinghouse report. There was, I guess, a May 11th letter where you say you've committed, and I just wonder did you make that commitment to MRP-227 and subsequent industry programs as part of the license

renewal or is that just in that letter of May the 11th?

MR. GIL: That commitment was made as part of the license renewal. In fact, we're in the process of signing a letter right now. It either went out this week or will be going out next week. We had previously submitted an internals program as part of license renewal, and that was one that we had developed internally. And what this letter is doing is making the commitment that we will follow the 227 document, which is what the industry is going to. Now, of course, in addition to the license renewal commitment, that is an industry commitment to implement that program. But that is the actual move to that 227 as just very recent. We're just submitting the letter. We had submitted previous letters with our intent to go to the 227 document, and now we've made the actual commitment that we will be following it.

MR. HALE: And the effects of the EPU have been factored in to our internals program.

MEMBER ARMIJO: Well, that's what I wanted to get at because in your documentation and also the staff's documentation there's a statement which says that there should be no increased susceptibility to

cracking due to SCC or PWSCC. I think the SCC includes irradiation assisting due to minimal changes in cooling temperatures. You know, I don't agree with that personally, but I just don't understand if the MRP program is based on that assumption that susceptibility to cracking is independent of the flux in the core and the temperature in the core. That seems a stretch --

MR. HALE: Well, certainly, irradiation-assisted stress-corrosion cracking is based on a certain threshold, and I think what we're speaking to there is around the core we were already above the threshold --

MEMBER ARMIJO: I know that.

MR. HALE: -- inspection criteria. And if anything did move above that threshold, it would be accounted for in the inspection program.

MEMBER ARMIJO: But there's no augmented inspection? There's no augmented chemistry changes to compensate for the increased in the core at EPU? Those are the kind of questions I wanted to get at and maybe you want to think about it or answer it now if it's okay with the chairman.

MR. GIL: Rudy Gil with FPL. We could provide additional details, but, basically, the

acceptance criteria and inspection criteria that's being developed and specifically for Turkey Point by Westinghouse takes into account the influences and all the impacts from EPU.

MEMBER ARMIJO: Yes, I would appreciate that.

CHAIR SHACK: Okay. Maybe this is a good time for a break. We can come back to steam generators, one of my favorite topics, at 10:30.

(Whereupon, the foregoing matter went off the record at 10:14 a.m. and went back on the record at 10:30 a.m.)

CHAIR SHACK: Let's come back into session. Mr. Hale, back to you.

MR. HALE: Yes. Back to Steve Hale, Florida Power and Light. I wanted to talk about steam generators. As you may recall, we had quite a bit of dialogue at Point Beach on steam generators and steam generator design and the assessments and evaluations that were performed. What we've done here is included the final slides that we put together for, I guess it was ACRS full committee to address all the questions that the committee had raised and, hopefully, this will answer any questions on the Turkey Point review.

MR. SHAFER: Do you want to cover some of

the open questions first?

MR. HALE: Yes, we can try and close a couple of the open questions. Sam had a couple. You want to address those --

MR. SHAFER: Yes, I'll go ahead and address it, if you all don't mind. Again, Sam Shafer from Florida Power and Light. The question was what was the actual RCS loop flows. For Unit 3, it's about 287,000 gallons per minute. That's what the actual measured flow was. For Unit 4, it's 283,000 gallons per minute. Now, with the proposed EPU, the tech spec limit will be about 270,000 gallons per minute. And for accident analysis, we're looking at about 260,000 gallons from the accident analysis. So we are looking about a 13 to 17,000 gpm margin from which --

CONSULTANT WALLIS: Why do you use gallons? I mean, the mass depends on density, doesn't it? And temperatures changes and then you get different amounts. You're always using gallons, and you have gallons at cold temperatures and hot temperatures, and it gets very confusing to me because gallons at the inlet temperature aren't the same as gallons at the outlet temperature. Why don't you just use mass?

MR. SHAFER: Good point, sir.

CONSULTANT WALLIS: We know what it means.

MR. SHAFER: Excellent point, sir.

CONSULTANT WALLIS: So you still use gallons even though the temperature is changing?

MR. SHAFER: Yes, sir. Actually, we use percent flow on our meters in the control room.

CONSULTANT WALLIS: Percent gallon flow?

MR. SHAFER: Percent flow in correlating to the gallon, yes. Did that satisfy the question on the actual RCS flows?

MEMBER ABDEL-KHALIK: I asked that question.

MR. SHAFER: Okay, thank you.

MEMBER ABDEL-KHALIK: So this is based on historical data for the surveillances that were done on the measured flow rate?

MR. SHAFER: That's correct, sir.

MEMBER ABDEL-KHALIK: Okay.

MEMBER SKILLMAN: Let's see. Just to address Dr. Wallis, your signal is coming from the delta-p across the LEFM for secondary flow and for primary flow it's delta-p? Your primary is a delta-p?

MR. SHAFER: Delta-p off the flow transmitters, yes.

MEMBER SKILLMAN: Okay. And flow

transmitter's delta-p is being developed by velocity and density?

MR. SHAFER: Looking at the elbow, it loops, so yes.

MEMBER SKILLMAN: It's density.

MR. SHAFER: Density.

MEMBER SKILLMAN: Even though it reads in gallons, it's thinking --

CONSULTANT WALLIS: Well, the density is in the numerator for gallons but in the denominator for mass flow. It's W squared over rho or G squared over rho, so it's double effect. But, anyway, the chairman said earlier that everything is rho v-squared so . . .

MS. ABBOTT: This is Liz Abbott from FPL. I think we look at it from the perspective of gallons in the tech specs because that correlates better to what an operator sees under normal plant conditions, so it really looks at when we perform the surveillance and does a comparison against the value that would be seen, you know, in the control room for verifying that we satisfy the flow requirements so --

CHAIR SHACK: He's just going to ask you why the control room doesn't show it in mass-flow, but that's okay.

MEMBER SKILLMAN: All gpm's are not the same is what he's saying.

MEMBER ABDEL-KHALIK: Will the change in temperature affect the calibration of the elbow flow meter?

MR. SHAFER: I'm assuming it does. I do not know what the magnitude of that change is. It's got to be within the set data sheet. It's got to be within that certain parameter when you do the calibration. It's accounted for.

MEMBER ABDEL-KHALIK: So those changes in the calibration will be confirmed? How would you go about doing that?

MR. SHAFER: Maybe I'm not understanding the question. When I&C does the flow transmitter calibrations for the 18-month fuel cycle, they have a set parameter that it's required to be within, so you've got instrument drift, is there any bias on the instrumentation itself? I'm not an instrument guy. I might be able to get more specific on the actual calibration procedure.

MS. ABBOTT: This is Liz Abbott from FPL again. Those types of changes are addressed in what Steve had identified as some of the I&C and setpoint and scaling modifications. So the scaling aspects are

addressed in those modifications, and they do reflect the actual physical parameter variations of the density associated with the temperature changes. So that's how that's addressed in the implementation process.

MEMBER ABDEL-KHALIK: Okay.

MR. SHAFER: Moving on to the second question was on the reach rods. When we do the surveillances, do we do it under the accident type conditions? The answer is, no, we don't do it during the accident type conditions. We do manipulate certain ones, as I mentioned previously, with flow through them. But, generically, for the surveillance requirement, it's not. We looked at the actual design of those valves or components with those reach rods. Similar to the MOVs that we have in the plant, they are designed to overcome the system delta-p when required to be manipulated as part of the design criteria.

MEMBER SKILLMAN: That was John's question.

MEMBER SIEBER: Yes. And I have to think about that answer a little bit because you want to assure yourself that when you have to operate it in actual conditions that you can operate it. And in the

1980s there was a big question within the industry and with the staff about being able to operate things under accident conditions where DPs are highest and flow resistance was often the greatest, and I think the regulations call for that to be demonstrated periodically. I'll have to look that up.

MR. SHAFER: That was it, Steve.

MR. HALE: Okay. The one question on the scope of the internals inspection, what we intended there is that the scope of the components that exceed the threshold for irradiation-assisted stress-corrosion cracking, the scope of what we needed to look at did not change for EPU.

MEMBER ARMIJO: I thought I read that there was one additional component.

MR. HALE: It was one additional one, okay, but that was already being included in the scope of our inspection program to begin with for other reasons besides irradiation stress-corrosion cracking.

MEMBER ARMIJO: So, basically, you would just inspect as you had done pre-EPU?

MR. HALE: That is correct.

MEMBER ARMIJO: And there will be no augmentation of water chemistry? There will be no augmented inspections --

MR. HALE: Required for EPUs specifically. That is true.

MEMBER ARMIJO: Okay. I understand your answer.

MR. HALE: Okay. Moving on to steam generator analysis. As I indicated, we tried to cover some of the specific dialogue we had with the committee on Point Beach. These were the items that were included in the LAR looking at the fluid elastic stability ratio, the amplitude of tube vibration, tube wear, and flow-induced vibration tube stresses. These were all --

MEMBER ABDEL-KHALIK: Now, in calculating the vibration amplitudes, how much fitting was assumed in that calculation?

MR. HALE: Kim, can you speak to that, please?

MR. ROMANKO: I don't believe there was anything evaluated --

MR. HALE: You need to identify --

MR. ROMANKO: Kim Romanko, Westinghouse. The tube, normal tube dimensions were used in the evaluation.

MEMBER ABDEL-KHALIK: Now, would you expect the vibration amplitude to be impacted by the

thinning of the tubes?

MR. ROMANKO: It would not be impacted significantly by the thinning of the tube. And if you look at the, say, for example, the amplitude that's given is 90 mills. It's far smaller than half the distance between the tubes.

MEMBER ABDEL-KHALIK: Well, that's not the question. The question is whether or not the vibration amplitude is impacted by the assumed tube thickness.

MR. ROMANKO: I would have to look at that and get back to you.

MEMBER ABDEL-KHALIK: Okay.

MR. ROMANKO: We'll just leave it at that right now. Let me look into that.

MEMBER ABDEL-KHALIK: All right.

MR. HALE: Okay. We did not reflect the actual numbers in the results. I have provided the LAR section where these actual numbers appear. This is proprietary information. I'm not closing the meeting. I just provided you with a LAR reference for that information is available.

CHAIR SHACK: When the tube stresses are met with margin, they were met with considerable margin?

MR. HALE: Yes, yes. So it is in the LAR, and I've provided that LAR reference.

CONSULTANT WALLIS: This tube wear, where is this tube wear occurring?

MR. HALE: It's basically at the tube support plates.

CONSULTANT WALLIS: That's where it's occurring. So it's very localized.

MR. HALE: Yes, yes.

CHAIR SHACK: Are some of the supports drilled hole and some are quatrefoil?

MR. HALE: We were one of the first steam generators with a quatrefoil, you know, stainless steel support plates. So --

CHAIR SHACK: But, I mean, all your support plates are stainless steel.

MR. HALE: Right. And they're the quatrefoil design.

CHAIR SHACK: But it says some of them are drilled hole, right? There was sort of a --

MR. HALE: I don't know if Rudy is here --

CHAIR SHACK: -- whether it was Unit 3 and 4 and there's some difference between the two. I was confused. I would have thought they would have been all quatrefoil.

MR. HALE: Yes. I was actually at the fabrication plant when they were building these and actually saw the quatrefoil support plates. Rudy can probably speak to --

MR. GIL: Yes, this is Rudy Gil. Yes, we have the quatrefoil design, and it's both units.

CHAIR SHACK: Okay. No drilled hole anywhere? Now, let me just find where that was in the license. Oh, drilled hole baffle plates. Okay. And broached quatrefoil tube support plates.

MR. HALE: Yes. It minimizes the actual area that would potentially contact the tube and provide room for growth and things like that.

CHAIR SHACK: But since you're doing this with -- how many tubes can you lose now and still be able to make the requirements? I mean, your allowance must have disappeared.

MR. HALE: They assume 10 percent tube plugging.

CHAIR SHACK: Even with the EPU?

MR. HALE: Even with the EPU, yes.

CHAIR SHACK: Well, you must have put in a fairly large margin when you did the first replacement.

MR. HALE: Yes.

CONSULTANT WALLIS: You assume 10 percent, but that's a big margin, isn't it?

MR. HALE: Yes, oh, yes. We plug maybe 60 or 70 tubes, something like that, so they have quite a bit of margin.

MEMBER ABDEL-KHALIK: With 10 percent plugging, how much will a steam generator pressure change?

MR. HALE: I believe that's in our, in a previous slide there because we look at all the cases here. Hold on a second. On the slide where we indicated the parameters, we didn't put steam generator tube plug in here, but we evaluate a range of temperatures and we evaluate a range of steam generator tubes plug. I would have to get back with you on that pressure.

MEMBER ABDEL-KHALIK: Okay.

MR. HALE: It certainly would change, would increase.

MEMBER SIEBER: Yes, it's Slide 11 is the one I think you're --

MR. HALE: Right.

MEMBER SIEBER: -- referring to.

MR. HALE: Right. But we can get that for you. That should be right in the LAR.

MEMBER SIEBER: Well, what was the original model steam generator; do you remember? You may not be able to know.

MR. HALE: No, I was there, I was there when we replaced them. We were one of the plants that were on phosphate and shifted to ADT.

MEMBER SIEBER: Yes, right. I remember.

MR. HALE: You know, carbon steel support plates, drilled holes.

MEMBER SIEBER: Well, I think the Model F. I may be wrong, and that's why I'm posing it as a question. But it had more square feet of heat transfer surface than the original ones for that plant. I think that's the case. And so you get margin that way.

CHAIR SHACK: Yes. I mean, they've actually done a -- how do you do this without a steam generator replaceable? They've done it, but they just did it a long time ago.

MR. HALE: Yes.

MEMBER SIEBER: Well, yes.

CHAIR SHACK: But come back to -- I mean, again, you have your potential rates for IG or propagation and initiation going up by 82 percent.

MEMBER SIEBER: Right.

CHAIR SHACK: That must be based on a nominal, that's not really Alloy 600TT data, right? That's based on Alloy 600 data, and you're somehow extrapolating that.

MR. HALE: Right.

CHAIR SHACK: It's a little fuzzy, but we've managed much worse steam generators than you're going to have so . . .

MR. HALE: Right. And the performance has been really good.

MEMBER SIEBER: Your only area of concern was the steam generators. In my mind is that you do have a pretty high T-hot for Inconel tubes, you know. It's up in the 618 range, right?

MR. HALE: We're actually around 616, I believe.

MEMBER SIEBER: Yes.

MR. HALE: But, again, you know, the four-loopers have been operating at temperatures above that for some time.

MEMBER SIEBER: Yes, yes, I guess I get uncomfortable above 611, but the degree of discomfort is linear with increasing temperature.

CHAIR SHACK: Now, Seabrook has Alloy 600TT, and it operates at like 620, right?

MR. HALE: Yes, 620, 619.

MEMBER SIEBER: You aren't going to set the record.

MR. HALE: Right. Definitely not.

MS. ABBOTT: Yes, this is Liz Abbott of FPL. To answer one of the questions, as shown on Slide 11 and I think it's also in chapter one of the licensing report, the steam pressures range from 701 to 822 psia. The 822, of course, corresponds to the zero percent steam generator tube plugging level, and the 701 corresponds to the ten percent steam generator tube plugging level.

MEMBER ABDEL-KHALIK: All right.

MR. HALE: Okay, next slide. Okay. This was the slide that we had put together that addressed questions from the committee for Point Beach. The rho v-squared was the high level interest point, you know, in terms of how we compare in the upper tube region. And as you can see, the Turkey Point is within the, you know, range of operating units that are out there, so we're not really pushing the steam generators beyond, you know, into territory where nobody has ever been I guess is the way to characterize it.

And next slide. Again, we've had many years of operating experience with no real indication

of vibration problems at Turkey Point. We do do periodic steam generator tube inspections. I think one of the questions was asked at Point Beach is whether we can inspect the inner tubes. Yes, we can with the type of inspection equipment that we have.

Although we don't anticipate any problems with the steam generators, we'll continue to inspect as we do today. And one important point of note that we will be inspecting the steam generators on Unit 3 after one cycle at EPU, so we'll actually have an inspection that we'll be performing after the first cycle in Unit 3.

MEMBER SIEBER: You're going to follow the tech spec regulated examination parameters, which is a sampling every so often. And as you find those, the sample size gets bigger and the frequency gets more frequent.

MR. HALE: I think we're doing full inspections, right, Rudy?

MR. GIL: Yes. This is Rudy Gil with FPL. We do follow all of the tech spec requirements. Like we go beyond and inspect, do some additional inspections regardless. Over a two-inspection period, we'll do 100 percent of the tubes.

MEMBER SIEBER: How many inspections --

MR. GIL: For Alloy 600 thermally treated, we skip one cycle, so every other outage we'll have an inspection specific for the EPU. So we will be doing an inspection on one generator after one cycle, as Steve mentioned, and then the other generator will be every two cycles. So we will actually have data after one cycle and after two cycles for our steam generators in order to -- of course, we look at any changes and then we'll act appropriately depending on what we see.

MEMBER SIEBER: Okay, thank you.

MR. HALE: Any other questions on steam generators? All right. With that, Carl and I will switch places.

MR. O'FARRILL: All right. I am Carl O'Farrill, and I'm the fuel engineering manager for Turkey Point. What I'd like to cover today is just an overview of the changes we had to make to our fuel and core design, as well as the safety analyses, to accommodate the EPU.

On the first slide, we had briefly discussed this earlier in the morning. We have previously transitioned over to a 15 x 15 upgrade fuel design which has the intermediate flow-mixing grids which provides us additional DNB margin. We're also

making minor changes to the fuel rod and the uranium loading to accommodate fission gas release. We currently have six-inch annular blankets on both top and bottom of the fuel rod, and we're going to eight inches to increase that plenum space to accommodate the higher fission gas release at EPU conditions. We're continuing to maintain the integral fuel burnable absorber loading of 1.25X.

MEMBER ARMIJO: You don't use any other burnable poison in your fuel?

MR. O'FARRILL: Currently, we do not. We may need to go to some alternate absorbers to manage the power distribution for EPU to maintain ourselves within the limit.

MEMBER SKILLMAN: What other units are going to use this annular blanket size and volume besides Turkey Point?

MR. O'FARRILL: It's typical for Westinghouse plants to have annular blankets, and they range in different sizes. I think at Point Beach we're actually going to eight inches, also. And they may have gone to longer and extended annular blanket, as well.

MEMBER SKILLMAN: Thank you.

MEMBER SIEBER: Have you evaluated 17 x 17

fuel?

MR. O'FARRILL: That change to our lattice would be a significant change, not just to the fuel assemblies but to the internals to accommodate the changes in the dimensions to their control rods.

MEMBER SIEBER: Oh, that's true. And what kind of control rods do you have?

MR. O'FARRILL: We have silver-indium-cadmium control rods.

MEMBER SIEBER: How old are they?

MR. O'FARRILL: I believe --

MEMBER SIEBER: Are they the originals?

MR. O'FARRILL: No, they are not the originals.

MEMBER SIEBER: Okay.

MR. O'FARRILL: And we have a lifetime in the management program for the RCCAs, as well.

MEMBER SIEBER: Well, control rods are expensive.

MR. O'FARRILL: But they're also very important, so that's why we want to maintain them within their lifetimes and assure ourselves that they are. The next slide. Core design links. We talked a little bit about this and some of the significant changes, but the power distribution peaking factors

are going to have to change as a result to accommodate the EPU conditions and the hot channel enthalpy rise factor, the F-delta H, is changing. The axial offsets, the actual power distribution range that enable ourselves to operate within that band is also being reduced, and the heat flux hot channel factor, F-Q, is also being reduced.

Now, we're continuing to use normal fuel management methods to meet these reduced limits, and we're going to manage within a range of feed enrichments, as well as batch size. That's the fresh --

MEMBER ABDEL-KHALIK: So what is the current batch size?

MR. O'FARRILL: It's approximately 56 --

MEMBER ABDEL-KHALIK: Fifty-six.

MR. O'FARRILL: -- out of 157. It's about a third of the core now, and we have looked at, at a minimum, 64 assemblies for EPU, ranging all the way to 72 assemblies for the extended power uprate. And, of course, the higher the batch size the lower the enrichment you have to have.

MEMBER SIEBER: Right. On the other hand, the higher the batch size and the lower the average fueling enrichment the smoother your overall flux

profile is.

MR. O'FARRILL: That's right. What we're attempting to do is --

MEMBER SIEBER: So you're making the tradeoff between what margin you need and how many fuel assemblies you can put in there, plus your spent fuel pool reactivity characteristics. Those are the three factors, right?

MR. O'FARRILL: That is correct.

MEMBER SIEBER: Okay.

MEMBER ARMIJO: What is the temperature increase at the top of the fuel, the cladding temperature increase before and after EPU?

MR. O'FARRILL: The cladding temperature? I'd have to get back to you on that, and I'll probably have to ask for Westinghouse to get me that number. So you're looking for fuel cladding at the top of the --

MEMBER ARMIJO: Right. Yes. What I'm trying to get at is, you know, actually at the oxide-metal interface is a temperature that controls the rate of oxidation, so I'm trying to get a feel for how much of an increase in corrosion rate you might expect as a result of EPU.

MR. O'FARRILL: Okay. A lot of that is

driven, on a localized basis, on the rod by this power peaking.

MEMBER ARMIJO: Yes. Whatever your peaking --

MR. O'FARRILL: So the flatter the power distribution the less of an effect you're going to have on a localized basis.

MEMBER ARMIJO: Right. But I'm looking at your peak temperatures.

MR. O'FARRILL: Okay.

MR. RODACK: Excuse me. This is Tom Rodack from Westinghouse.

MEMBER ARMIJO: Hi, Tom.

MR. RODACK: Is that better? Tom Rodack from Westinghouse. With regard to temperature, if you're in subcooled boiling, because of the high-heat transfer coefficient, we really wouldn't expect very much of an increase in the clad temperature. We can get back to you with a specific number, but I would expect the increase to be very small.

MEMBER ARMIJO: Okay. Because you're actually steaming? Otherwise, it should go up.

MR. RODACK: Right, yes.

MEMBER ARMIJO: Okay. That may explain what my problem was.

MR. O'FARRILL: Okay. Just going on, in burnable absorbers, we did mention that we are using the burnable absorbers, but we're also looking at alternate absorbers in order to control the peaking factors in the core, as well.

Oh, in the safety analysis, what we do is we have a set of core designs that are typically limiting for EPU conditions and try to get physics characteristics that are going to be bounding for us for future core design, so we can perform the safety analysis and then check on a reload-by-reload basis that the core design is within those physics parameters.

Shutdown margin is one of the things that is changing as a result of EPU. Obviously, we'll have a larger doppler defect coming from hot full power down to hot zero power when we trip the reactor. But we're still maintaining significant margin to the limits for shutdown margin, even after EPU.

RCS boron requirements are also going up. As an example here on the slide, we're showing about 300 ppm for Mode 6 type conditions to maintain the 0.95 criteria K-effective.

MEMBER SKILLMAN: Carl, it's probably not your areas. It's more the plumbing. But with an

increase in boron concentration, that puts an increased service load on all of the auxiliary equipment that is used to provide that increase and to provide the increased amount of boron that is linear or a logarithmic function that takes large volumes of water to affect the change in a reactor coolant system boron concentration.

MR. O'FARRILL: Right. And we did look at the CVCS system's ability to deliver the requisite amount of flow for rapid cool down, a shutdown and a rapid cool down, as well, to assure ourselves that we'd be able to meet those shutdown margin conditions, as well, as part of the EPU conditions.

MEMBER SKILLMAN: Can you speak to the outcome of those analyses, please? Maybe someone here can. That is a hefty change in boron concentration.

MR. O'FARRILL: Let me back up. That is the change that is in the RWST boron concentration, which is, in the way we have our tech specs now, we are changing from 1950 requirement there to 2300 is the minimum that we have. So that's where the 300 comes from as a hefty change, and what we have to do in Mode 6 is meet either that value or a 0.95 value. Typically, it is that value that sets the Mode 6 boron concentration.

MEMBER SKILLMAN: You've got to move a lot of water to get there is my point.

MEMBER SIEBER: Yes, but that's only during shutdown.

MR. O'FARRILL: That's only during shutdown. The CVCS capabilities that we're talking about, since that comes from the RWST, we have time to borate up to that conditions for shutdown conditions. The CVCS capability is more in going from hot full power down to hot zero power and then cooling down to cold shutdown conditions, and those boron concentrations are a little bit less and I'd have to get back to you as to what maximum we're targeting as part of that analysis.

MEMBER SIEBER: I'd imagine for normal operation your RCS boron concentration does not vary very much from what you previously experienced during, you know, previous cycles prior to the uprate; is that correct?

MR. O'FARRILL: Yes. It is increasing because we're increasing --

MEMBER SIEBER: But not --

MR. O'FARRILL: -- but not 300 ppm's --

MEMBER SIEBER: Like 50 ppm or something in that range.

MEMBER SKILLMAN: I certainly understand that. This is your shutdown. Yes, I understand.

MEMBER SIEBER: You're on an 18-month cycle?

MR. O'FARRILL: We're on an 18-month cycle.

MEMBER SIEBER: Okay.

MEMBER ABDEL-KHALIK: Now, how much excess reactivity do you have in a cold clean core?

MR. O'FARRILL: At EPU conditions?

MEMBER ABDEL-KHALIK: Right. At the higher enrichments.

MR. O'FARRILL: Well, I can relate it to you in boron concentration.

MEMBER ABDEL-KHALIK: Well, I can translate.

MR. O'FARRILL: Okay. So we're looking at boron concentrations around 1200 ppm at hot full power conditions, so, obviously, throughout the cycle we go to --

MEMBER ABDEL-KHALIK: No, no, no, I'm asking about excess reactivity in a cold clean core.

MR. O'FARRILL: Oh, cold clean core.

MEMBER ABDEL-KHALIK: Right.

MR. O'FARRILL: So you're looking for the

hot zero power.

MEMBER SIEBER: That's where the 2200 comes from.

MR. O'FARRILL: Right.

MEMBER SIEBER: That's 0.95.

MR. O'FARRILL: Let me get back to you as to what those values are.

MEMBER ABDEL-KHALIK: Okay.

MEMBER SIEBER: It's going to be close to that but not as high as that.

MR. O'FARRILL: Correct.

MEMBER SIEBER: Your normal operations is, I presume, with slightly embedded rods?

MR. O'FARRILL: No, it's actually all rods out.

MEMBER SIEBER: All rods out?

MR. O'FARRILL: Yes. We're base load operations, so we're typically operating with all the rods completely out of the core.

MEMBER SIEBER: Okay.

MR. O'FARRILL: The next slide. I'll talk a little bit about the methodology changes in the safety analysis. We have gone to a COBRATRAC with ASTRUM for the large-break LOCA analysis, and we've transitioned to RETRAN for the non-LOCA analysis. We

have used LOFTTR2 for the steam generator tube rupture and transitioned for DMB analyses at VIPRE code and then GOTHIC for our containment response analysis.

MEMBER ABDEL-KHALIK: So all non-LOCA transients are done with RETRAN, including loss of feedwater ATWS?

MR. MONAHAN: This is Ed Monahan from Westinghouse. No, we still use the LOFTRAN code for the ATWS events. Recently, with the RETRAN methodology, it wasn't approved for ATWS at that time, so we continue with LOFTRAN.

MEMBER ABDEL-KHALIK: So this statement is not correct? You don't to indicate that LOFTRAN is being used for any of the transients.

MR. MONAHAN: Yes, I think we mention that in a further slide, I think. But, yes, there are a couple of transients where we still have fell back on LOFTRAN.

MEMBER ABDEL-KHALIK: Okay.

MR. O'FARRILL: Next slide. Just to summarize some of the key beneficial changes to the safety analysis to accommodate EPU. The improved methods that we mentioned, the reduction in the power peaking factors, both radial, local, and axial. We continue to have conservative assumptions for physics

parameters in order to bound future reload designs. We also have bounding plant parameters, as well, and conservative trip setpoints. As part of the Westinghouse methodology, we maintain a safety analysis DMB limit that is higher than the design limit for DMB.

MEMBER ABDEL-KHALIK: Do you ever have positive MTC at the beginning of cycle?

MR. O'FARRILL: Only at zero power, never at --

MEMBER ABDEL-KHALIK: Only at zero power. And operators have been trained to handle that?

MR. O'FARRILL: That is -- well, operations can speak to that, but yes --

MR. SHAFER: This is Sam Shafer from FPL. Yes, during our just-in-time training, whenever we're starting up the reactor on a new fuel cycle, we do challenge that to make sure that the operators will be able to handle any transients that could come their way.

MEMBER ABDEL-KHALIK: And how positive is a small positive MTC at the beginning of cycle? Does it go up to three pcm per degree, for example?

MR. SHAFER: Per the simulator modeling, I believe they tried to model it with the actual MTC

that's in there for the actual fuel cycle, so it's probably going to be like a plus one.

MEMBER ABDEL-KHALIK: Plus one.

MR. SHAFER: That's correct, sir.

MEMBER ABDEL-KHALIK: Okay. Thank you.

MR. O'FARRILL: Okay. Next slide. We mentioned some of the modifications we made for safety analysis, but I'd like to highlight some of the key ones for the safety analysis. We did talk a little bit about the setpoint changes for the safety relief valves, both on the secondary and the primary side. We're also changing the steam generator low-level trip setpoint and increasing that to provide us additional margin. And when we did talk about the aux feed flow and removing the stops on those valves and refurbishing the aux feed pumps to get us the additional flow from auxiliary feedwater.

MEMBER SKILLMAN: Before you change this slide, what sensitization has the utility done in the control room simulator to implement these changes in your simulator to give the operators a sense of the changed dynamics of the plant under the EPU conditions? I mean, you lowered your main steam safety valve setting; you've changed some of your blowdowns; you've changed some of the what are going

to be the dynamic relationships between feedwater flow, reactor coolant system temperature, moderator temperature coefficient, those types of things. What action has been taken to introduce the operating team to what is the new dynamic of the plant? It's a different plant.

MR. SHAFER: Again, Sam Shafer, Florida Power and Light. Part of the just-in-time startup testing that we'll be doing is going to be all done while we are de-fueled. So, currently, the models in the simulator outage will be about a one-month period. At that time, we'll be inputting into all the new EPU parameters. There will be a startup testing that tests it all. During the de-fueled window, every operator on site will be going through the simulator testing every one of these scenarios to make sure that they fully understand the impacts of all the changes that we're talking about.

So, currently, what's being done in training is tabletopping, walking through the plant-specific design component changes, looking at the parameters and the margins that we're going to gain or lose. That's done in a tabletop fashion, but once we update the simulator that's when we'll be running all the crews through there. And that target right now is

about February for the simulator outage, and we're looking at the beginning of March to start the simulator training.

MEMBER SKILLMAN: Thank you.

MEMBER ABDEL-KHALIK: Now, on the third bullet, what is the normal narrow range in generator level?

MR. SHAFER: A hundred percent power narrow range, steam generator level is about 60 percent. It's our program level; that's correct. With EPU, it would be coming down to 50 for the 100-percent program level.

MR. O'FARRILL: Okay, next slide. I just wanted to touch on the high-neutron flux reactor trip setpoint also being lowered, and we did discuss earlier the crediting the tube, the configuration that we have for the two high-head safety injection pumps, and we did discuss the RCS flow requirements, as well.

We sort of touched on this before. These are the changes that we're making, LOFTRAN to RETRAN. We're continuing with the point kinetics methodology as part of it. We are crediting the methodology for the thick metal mass heat transfer, as well. And we are doing a steam line break at hot full power conditions, which is not previously part of our

licensing basis.

Next slide. I'd like to cover some of the transient results with some of the key transients for non-LOCA. The loss of flow. What we're showing here is what the acceptance criteria in the third column and then the results from the analysis in the fourth column, indicating that we have maintained margin for that event. For the overheating event, we look at loss of load, and we're maintaining margin there, and I think we talked about that earlier about the capability of the pressurizer and steam safeties, and this is the limiting event for over-pressure. So we're still maintaining margin to the limits, to the RCS limits for those, as well.

MEMBER ABDEL-KHALIK: What's the uncertainty in that calculation?

MR. O'FARRILL: The uncertainty in that?

MEMBER ABDEL-KHALIK: I mean, you know, your result is --

MR. O'FARRILL: Within a couple --

MEMBER ABDEL-KHALIK: -- the criterion.

MR. O'FARRILL: Although I could say it's actually an improvement of our current licensing basis because we had made the changes for EPU to change the setpoints on the safety valve to provide us additional

margin, and it did gain us some from where we are currently. However, this analysis is one of the analyses that's done deterministically, and all the uncertainties, both in the initial conditions as well as all the trip setpoints and the settings, are done at the far end of the tolerance band, everything. For instance, we have three pressurizer safety valves, and we assume all three of them are at the three percent tolerance limit. So in reality you'd never have three of them all out at that level. So there's embedded conservatism in how the analysis is done.

MEMBER SKILLMAN: Your reactor coolant system design pressure is 2,500 psig; is that accurate? Design pressure.

MR. O'FARRILL: Our nominal design pressure?

MEMBER SKILLMAN: Yes.

MR. O'FARRILL: Well, 2250 normal operating, but the design pressure is 2748 and a half psia.

MR. MONAHAN: This is Ed Monahan from Westinghouse. Are you talking about the limit? It's 110 percent of the design pressure.

MEMBER SKILLMAN: That's where I'm going. That's exactly where I'm --

MEMBER SIEBER: Pressure is 2500.

MR. MONAHAN: That's correct.

MEMBER SIEBER: So you have 250 pounds --

MEMBER SKILLMAN: So let's go back. The design pressure is 2,500 and --

MEMBER SIEBER: And --

MEMBER SKILLMAN: -- takes you up to 2750, right? So you're skating by here by the skin of your teeth; is that accurate?

MR. O'FARRILL: By two pounds margin.

MEMBER SKILLMAN: Yes, yes. Any landing that's successful is a good landing; is that what you're saying?

MR. O'FARRILL: With the embedded conservatisms in there, yes.

MEMBER SKILLMAN: I understand. Just making my point. Thanks, got it.

MR. O'FARRILL: Okay. The other cooling accident, it's a steam line break. You can see the results here. Plenty of DNB margin. Let's also look at the criteria, as well, for these two events, both the hot full power and the hot zero power.

CONSULTANT WALLIS: These DNBR limits, they seem to be plant-dependent, aren't they? I mean, the safety analysis limit has some margins which

somehow you decide they're okay. I don't think there's a universal DNBR --

MR. O'FARRILL: Well, the key --

CONSULTANT WALLIS: -- limit accepted for all plants.

MR. O'FARRILL: It's a safety analysis limit in order for us to maintain margins --

CONSULTANT WALLIS: I understand that.

MR. O'FARRILL: -- to the design limit. Right.

CONSULTANT WALLIS: How you decide what's an adequate limit. I mean, one is a sort of absolute limit, and you add things on to it and I've never been quite clear about -- because they're not specified by Westinghouse, are they? That's something that you do.

MR. O'FARRILL: Well, there's a correlation limit for --

CONSULTANT WALLIS: That's the Westinghouse one. That's --

MR. O'FARRILL: Correct. Then there's a design limit that we have that is part of the statistical treatment for DNB that convolutes power, flow, and temperature uncertainties into that limit. So you'll get something on the order of 1.2 --

CONSULTANT WALLIS: Extra stuff.

MR. O'FARRILL: Right. And then you say I want to have margin to that design limit when I'm designing my transients and my accident analysis for DNB space, and that's when you establish the 1.40, and it's fuel dependent.

CONSULTANT WALLIS: So there's more margin than what's really apparent here.

MR. O'FARRILL: Yes, it's embedded in that safety analysis.

CONSULTANT WALLIS: That's right.

MEMBER ARMIJO: In your linear heat rate, you've got 0.04 kilowatts per foot margin to your criterion. What happens at when you're at those powers and exceed that criterion? Is that melting of the fuel or what else?

MR. O'FARRILL: That is a center-line melt.

MEMBER ARMIJO: Center line melt.

MR. O'FARRILL: It's the power-to-melt limit that we have.

MEMBER ARMIJO: Okay. And that would be on your peak rods, peak nodes, or --

MR. O'FARRILL: Yes, it would be peak rod and peak local location on that fuel rod.

CONSULTANT WALLIS: So what do you quote

as the five significant figures? Is that meaningful?

MR. O'FARRILL: Well, in this case, there's plenty of margin to that. So, no, in this case, it's not that significant --

CONSULTANT WALLIS: Because if you look up these linear heat rates, they're very close to the margin. They're very close to the criteria.

MR. O'FARRILL: Well, what we're representing here is the bounding analysis that was done for EPU, and that's something that we check every reload as to whether we're satisfying those limit at the state points for the steam line break.

MEMBER ABDEL-KHALIK: And this is done with an MTC value of minus 41 pcm per degree?

MR. O'FARRILL: That is correct. The most -- actually, it's done with even more negative for the steam line break. We're doing --

MR. MONAHAN: Yes, for the actual analysis, we modeled actually a much worse condition. We modeled a density coefficient of 0.5 delta K over grams per cc. I'm not sure what that --

MR. O'FARRILL: It translates into minus 52 for the MTC limit.

CONSULTANT WALLIS: If you look at this linear heat rate of 22.72 and 22.68, I just wonder if

you can calculate it with that accuracy. I mean, there are unknowns that goes into this.

MR. O'FARRILL: We do, when we calculate the kilowatt --

CONSULTANT WALLIS: You can predict. Let's say you can predict because, you know, the numbers that you've put in are not exact.

MR. O'FARRILL: The way we do this calculation is we add on those uncertainties when we do the comparison of the limit --

CONSULTANT WALLIS: This is an upper limit?

MR. O'FARRILL: Correct.

CONSULTANT WALLIS: Five significant figure.

MR. O'FARRILL: Okay. Next slide.

MEMBER SKILLMAN: Let's go back to this for a second. I want to circle back around on a point here.

MR. O'FARRILL: Okay.

MEMBER SKILLMAN: On this reactor coolant system pressure, that is really right up to the mechanical limit. When I asked earlier about whether or not you changed the internals on your main steam safety valves, if you changed the area, the answer was

no.

MR. O'FARRILL: Right.

MEMBER SKILLMAN: It seems to me that this slide points toward the potential need for greater heat removal early on out of secondary to draw down primary pressure. What we've learned over the years is your primary pressure, what is going on in the pressurizer is really telegraphing what's going on in the steam generator and vice versa. And so even though you have lowered your main steam safety valve setpoints, I'm wondering if you're drawing down enough heat to keep from getting this close to your final mechanical limit on the reactor coolant system pressure.

MR. O'FARRILL: We've also lowered the primary safety relieve valve settings, as well, as part of this event. It was a combination of both.

MEMBER SKILLMAN: But doesn't this point to the need for a greater mass blowdown so that you don't come this close? I mean, it seems as though this analysis might cause one to say, gee wiz, we're in good shape, you know, hot diggity, we didn't go over 2750. But it seems, you know, in almost every other place you've got what one would say fairly robust margin, but you're really at the limit on this

one. And it's not just an imaginary limit. This is a very significant parameter if you're to fail primary. Now you've gone from a loss of secondary cooling to a LOCA. It just strikes me that the margin here is remarkably thin compared to the other picture you're painting. If I'm wrong or if that's not an accurate picture, I'm happy for you to say that that's not accurate, but that's certainly what I see when I look at this number.

MR. MONAHAN: This is Ed Monahan from Westinghouse. One of the other things about the analysis that isn't maybe reflected here is the design of the Turkey Point pressurizer safety valve as a loop seal filled with water that is used to keep the valve from leaking during normal operation. And we model a pure delay on the opening of the valve to reflect the time it takes to blow that water out. So although the setpoint is set a certain pressure, there's no relief in our analysis until that conservative delay time is over. And it can be, I think we calculated a little over a second of pure delay. So it makes the results look I think worse than they are because just the way the valves work and how we consider that pressure relief.

MEMBER SKILLMAN: Have there been RAIs on

that topic that you've responded to?

MR. MONAHAN: Yes. There was a topical report written several years ago on the subject of the loop seals and how the safety valves perform for these type of valves. I don't recall the number exactly, but it was kind of an industry type of an issue.

MEMBER SKILLMAN: So if one factored out that conservatism, what would the result be?

MR. MONAHAN: Well, this transient, the pressure is going up roughly between 50 and 100 psi per second at this time frame, so that second or a little over a second we're modeling could be as much as, you know, 50 to 100 psi. And then the actual pressurization is determined by the reactor trip, which you hit fairly quickly in this event.

MEMBER SKILLMAN: Thank you. Thank you.

MEMBER ABDEL-KHALIK: So you'll get back to us about the historical data for the safety valves on the secondary side?

MR. O'FARRILL: Yes.

MEMBER SKILLMAN: Next slide is the reactivity addition events, rod withdrawal at power, and rod ejection, both showing margins to the limit and the results.

MEMBER SKILLMAN: What temperature do you

model for rod ejection, please?

MR. MONAHAN: You mean RCS temperature?

MEMBER SKILLMAN: Yes.

MR. MONAHAN: This is Ed Monahan. We modeled two cases, one at zero power and for that case it would be the no-load temperature, like 547. The full power cases we model I think the nominal T average, whatever it is, 580.

MEMBER SKILLMAN: Five eight-three I think is what you --

MR. MONAHAN: Yes.

MEMBER SKILLMAN: -- I think modeled here. Thank you. Thanks.

MR. O'FARRILL: Next slide is the small-break LOCA. These are some of the key changes that we made for small-break LOCA.

CONSULTANT WALLIS: This fuel enthalpy for the rod ejection, is that a moving target? I thought it was 180 or something like that. Has the NRC changed it?

MEMBER ABDEL-KHALIK: The 200 you mean?

CONSULTANT WALLIS: It's on 200. We have debates about this from time to time.

CHAIR SHACK: Well, there are numbers like 280, 200, and then there are observed numbers. This

is sort of a gentleman's agreement that we don't believe that the limit, that they have so much conservatism in the calculation that you live with it.

CONSULTANT WALLIS: But 200 is now the official accepted value, is that it?

CHAIR SHACK: No, but they'll accept this analysis.

CONSULTANT WALLIS: The criterion, is that criterion not in our . . .

CHAIR SHACK: That's a Westinghouse criterion.

MR. MONAHAN: Right. This is Ed Monahan. That's a Westinghouse criterion, which is, I think, lower than the actual NRC criterion at the moment.

MR. O'FARRILL: Okay. Small-break LOCA. Some of the changes that were made to accommodate EPU in the small-break LOCA increase in power for EPU was, again, the power peaking factors, looking at the hot channel enthalpy rise, reduce the f-delta 8, the axial offset assumptions being reduced, and reducing the steam generator to plugging levels, as well. But, primarily, the majority of the benefits are coming from the two hot-head safety injection pumps for this event. And on the next page of the presentation, we can see the results, comparing where we are pre-EPU to

EPU and showing even a reduction as a result of making these changes.

CONSULTANT WALLIS: Is this the statistical PCT, or is this --

MR. O'FARRILL: Oh, no, this is small break.

CONSULTANT WALLIS: Small break, so it's just one calculation?

MR. O'FARRILL: Yes.

CONSULTANT WALLIS: But it's got conservatisms?

MR. O'FARRILL: Right. Conservatisms in the analysis, yes.

MEMBER ABDEL-KHALIK: Now, what is the shutoff help for your high-head safety injection pump?

MR. O'FARRILL: Sixteen hundred, seventeen hundred pounds.

MR. SHAFER: Sam Shafer, Florida Power and Light. It's about 1600 pounds.

MEMBER ABDEL-KHALIK: Sixteen hundred psi.

MR. SHAFER: That's correct.

CONSULTANT WALLIS: But one is less than one? I don't quite understand that. Less than one is considerably less than one. When you say maximum cool water oxidation is probably very small, so it's

misleading to say it's less than one, 0.998 or something, but it's really much smaller.

MR. O'FARRILL: With a pct of 12 --

CONSULTANT WALLIS: It would nice if you actually could quote a number.

MR. O'FARRILL: Do you need a number?

CONSULTANT WALLIS: Well, it's more convincing than just saying it's less than one.

MR. O'FARRILL: Okay. Next slide. Large-break LOCA results. This is, again, comparing pre-EPU to EPU analyses, so it accommodates the methodology change, as well as the EPU condition change. And we're seeing -- this is a statistical analysis, so the 95 95 peak cladding temperature is going from --

MEMBER ABDEL-KHALIK: Let me just go back to the small-break LOCA. If you had stayed with one high-head safety injection pump, what would be the calculated peak clad temperature? Have you done that calculation?

MR. O'FARRILL: I don't believe we did that for -- I don't know that we have the -- Westinghouse know that answer, but I don't believe we looked at just one high head. We were assuming, we knew we had to go to two high-head safety injection pumps to provide us margin both for the large break,

as well as the small-break, LOCA.

MEMBER ABDEL-KHALIK: Okay.

CONSULTANT KRESS: In your statistical analysis, what were the variables that you put a distribution on? Thermal conductivity? Heat capacity? Flow rate?

MR. O'FARRILL: Perhaps, Westinghouse can cover all those.

MR. FREPOLI: This is Cesare Frepoli. Could you please restate the question?

CONSULTANT KRESS: I was interested in your statistical analysis for the peak clad temperature. In a lot of the variables, you actually put a distribution on and varied in your analysis.

MR. FREPOLI: Oh, there are several parameter, you know, or ASTRUM sampling, random sampling. I think it will be over 40 parameters but it's --

CONSULTANT KRESS: Was heat capacity one of them?

MR. FREPOLI: Heat capacity? No, that's not specifically range, but if you're referring heat capacity with the fuel --

CONSULTANT KRESS: Oh, of course.

MR. FREPOLI: In that case, we kind of de-

aggregate the fuel temperature that we use as an uncertainty parameter because we calibrate the fuel temperature at initial, at the beginning of the transient to what produce from the fuel performance code.

CONSULTANT KRESS: Did you vary the components of the heat transfer coefficient from the fluid flow findings?

MR. FREPOLI: Yes, those are all part of the uncertainty methodology. As you go through a large-break LOCA, you go through your blowdown. For each of those phases, we have a subset of separate factors where the code is validated against to. And from each of those phases, then we have a multiplier or, say, a bias that we apply to the heat transfer. And it's statistically based, so it's going to have like a distribution and we're going to sample from those distributions.

CONSULTANT KRESS: Okay.

CONSULTANT WALLIS: Does Westinghouse do this calculation for you?

MR. O'FARRILL: Yes, they do.

CONSULTANT WALLIS: Cesare, do you look at the distribution? Because if it's a sort of normal distribution, you say 264 is just a tail. But it

could be a double hump distribution where you've got -- how many do you have? A hundred and twenty-one runs or something? You could have 60 runs at 1200 and 60 at 2,064, in which case I would be concerned about having 60 up there at 264. But 264 is a real outlier and not everything is around the mean, I wouldn't be so concerned. Do you look at the statistical distribution?

MR. FREPOLI: Well, as you're probably familiar with the methodology, we use a known parametric statistic. You can look at a histogram of the sample. Typically, if you do a normality check on the distribution, it looks like, visually, like a bell-type of distribution.

CONSULTANT WALLIS: It looks like a bell type.

MR. FREPOLI: But also we need to keep in mind that we're sampling the one on the 24 and then we can get more into that story, but, you know, it's very --

CONSULTANT WALLIS: You have to look at the distribution because there were odd features like this double hump with a lot of points upper 2064 instead of just one outlier I would be more concerned. So I think you have to look at the distribution, not

just do the statistics and say it's only --

MR. FREPOLI: No, we look at things, looking at rank one, rank two, rank three, how far they are. But at the end, we need to leave with what we have as far as the --

CONSULTANT WALLIS: I understand that, but you do have to intelligently look at the results and say is there something odd about the distribution?

MR. FREPOLI: Understood, yes.

CONSULTANT WALLIS: Do you have any idea what conditions lead to this maximum value, which is so different from the mean? What is it that drives it up there?

MR. FREPOLI: I don't have the information available, but I can provide that --

CONSULTANT WALLIS: That would be interesting to know, yes. Thank you.

MEMBER ABDEL-KHALIK: If we go back to the small-break LOCA and the requirement for the two high-head safety injection pumps, what is your LCO for one high-head safety injection pump out of service?

MR. SHAFER: Sam Shafer, FPL. One high-head pump has a 30-day action.

MEMBER ABDEL-KHALIK: Thirty days?

MR. SHAFER: Thirty days. That is

correct, sir.

MEMBER ABDEL-KHALIK: And that will not change with this change in requirement?

MR. SHAFER: That is correct, sir.

MR. O'FARRILL: When we shifted the analysis from a single, from two pumps to a single pump, we did not change the original tech specs. We essentially maintained those same tech specs, always recognized that we had the four high-head safety injection pumps shared between the two units and were available.

MEMBER ABDEL-KHALIK: Right. Because we're evaluating, you know, one event in one unit at a time.

MR. O'FARRILL: Correct.

MEMBER ABDEL-KHALIK: And the staff was happy with that, that you don't change the LCO for one high-head safety injection pump out of service? I guess we'll ask when the time comes.

MR. PARKS: This is Ben Parks with the Reactor Systems Branch. I considered their LCO, and because their LCO pertains to both units it's a little bit different. But I did review that, and I plan to discuss that during our presentation.

MEMBER ABDEL-KHALIK: Great, thank you.

CHAIR SHACK: Just to address your question, the upper bound exceeded all other values by at least 64 degrees.

CONSULTANT WALLIS: Okay. So it is a tail.

CHAIR SHACK: The lowest predicted one is a thousand F. This is from the staff's SEU --

CONSULTANT WALLIS: There is a big spread. There is a big spread.

CHAIR SHACK: Right. And the greatest number of cases occurred in the 1600 to 1650 range.

CONSULTANT WALLIS: But the staff, from the looks of this --

CHAIR SHACK: The staff looked at it.

CONSULTANT WALLIS: We can ask the staff the same question.

MEMBER ARMIJO: I have a question on your maximum local oxidation. Now, the acceptance criterion, as you know, of 17 percent oxidation is currently being looked at by the staff and rulemaking going on, and that criterion is going to change to be burn-up dependent, hydrogen pick-up dependent. Has FPL looked at the ability of your plant at EPU to live with these perceived new requirements? You're not obligated yet. There's a rulemaking going on and a

lot of things can happen, but has there been any assessment of ability for your cores to --

MR. O'FARRILL: I don't know if Cesare knows this or Westinghouse knows what we've looked at as part of the Owners Group, and I don't know how far they have gotten --

CHAIR SHACK: The Owners Group results have your EPU, have estimates for your EPU conditions. It's in that big table.

MEMBER ARMIJO: It's in the big table that I --

CHAIR SHACK: It's in the big table. Now, whether I believe them or not is another question. But there are estimates in there because, actually, it has different values for your pre-EPU than you show here. It's got 2067 in the table, but it does have 2064 for the EPU. But according to the table, they're okay.

MEMBER ARMIJO: Okay. Even with Zirlo?

CHAIR SHACK: Even with Zirlo. The margin might not be as big --

CONSULTANT WALLIS: With a statistical method, it's not repeatable. You do another --

CHAIR SHACK: That's true.

CONSULTANT WALLIS: -- run, another set of

runs, you get a different number.

MEMBER ARMIJO: Okay. At least it's been looked at and then there's no cliff out there.

CHAIR SHACK: We'll talk about it tomorrow.

MEMBER ARMIJO: We'll talk about that tomorrow, yes.

MR. O'FARRILL: Okay. Next slide. I think you had noted the footnote, and I believe that staff had mentioned it earlier about the emergent issue regarding the fuel thermal conductivity degradation. We just want to give you an overview, since this is late-breaking information that we have, what we're doing now to assess the impact of that. The first slide here is just a historical quickly to go through from the Halden test data in the 90s indicated that the fuel thermal conductivity degradation may have been greater than previously thought. An information notice was put out by the NRC in late 2009 to the licensee indicating that since many of the fuel performance codes were licensed prior to having this additional data that it may not have incorporated the new test data at Halden appropriately.

In our previous assessment by Westinghouse

on the code that they use indicated that we had sufficient conservatisms to offset the impact of thermal conductivity degradation at the time. Nevertheless, the code itself does not have an explicit model for thermal conductivity degradation, and so Westinghouse embarked on a program to update their fuel performance code and is in the progress of doing that now to include an explicit thermal conductivity degradation model.

Next slide. Recent conservative estimates, as recent as last week, indicated that the impact of thermal conductivity degradation on fuel average temperature may be higher than anticipated. However, the preliminary assessments show that the fuel average temperature at zero burn-up remains higher than even the fuel average temperature at higher burn-ups when compensated for thermal conductivity degradation, an important fact because many transients and local effects are dependent on power distribution, localized power distribution, and those peaks, limiting peaks occur at the beginning of cycle at very low burn-ups. Nonetheless, we're addressing the impact on EPU of this phenomenon.

MEMBER ARMIJO: Are these recent estimates just calculations, or is there any new data compared

to the old Halden data?

MR. O'FARRILL: I don't believe there's any new data, but, Tom, perhaps --

MR. RODACK: No, these are not new data. They're calculations.

CHAIR SHACK: Calculations of the effect of the data change? I mean, how it changes at peak clad temperature.

MR. RODACK: Yes. If I may?

MEMBER ARMIJO: Yes, please.

MR. RODACK: This is Tom Rodack from Westinghouse. We have, as Carl said, we've got an ongoing program to upgrade our fuel performance code where we'll be including not just an explicit thermal conductivity degradation model but changing a number of other models and benchmarking to data that we're just obtaining now.

However, relative to the need to address the impact of thermal conductivity degradation, we do have information available to us. We have our STAV fuel performance code which is licensed for BWR fuel but not PWR, and STAV contains thermal conductivity degradation model. It's the Halden model. What we did was took that and created a version of the PAD fuel performance code with this thermal conductivity

degradation model.

Fuel performance modeling, the code is an in-graded package, so we made also a correction to the fission gas release so that we maintain the same number of moles of fission gas released with the pellet thermal conductivity degradation modeled. Those are the primary adjustments we made to PAD to use it to come up with these assessments, so, you know, we took the Halden model, put it into PAD, corrected for first-order effects, and then applied it, and then evaluated the effect, did a comprehensive assessment of the effect on fuel design criteria and also safety analyses. And this --

MR. O'FARRILL: Tom, that's what this slide is showing here. We wanted to have a comprehensive assessment to make sure that we looked at all the potential impact areas.

MEMBER ARMIJO: Well, what I'm trying to get at, you know, the previous assessments weren't that detailed apparently when the previous assessments indicated there was sufficient conservatism within the codes. And so what I'd like to get at is what is the increase in peak clad temperature with the current assessment as you're going, that you've recently determined? How big a number is it?

MR. O'FARRILL: Our assessment kind of looked at it at the aggregate and said what available margins do we have in PCT, what available margins do we have in power distribution in order to make a determination --

MEMBER ARMIJO: Well, give me available margins before and after. I'm just trying to see the magnitude of this finding.

MR. HALE: If we could, you know, certainly, it's a tradeoff between peaking factors in the effect of -- you know, our primary thrust at this point is to look at reducing peaking factors in order to accommodate the effect. Our approach right now and the assessments we have done, we feel we can, we're targeting like about 50 degrees of margin. So it's kind of hard to compare apples to apples. Right now, we have, based on the analysis we performed, approximately 135 - 136 degrees between our actual PCT calculated versus the limit. With accommodating the effects of TCD plus offsets with peaking factors and things of that sort, we're targeting about, you know, a 50-degree margin, 2150 basically. And based on these assessments, we think we can get there, but it's hard to compare all the, you know --

MEMBER ARMIJO: There would be, would

there be fuel design changes or methodology changes to get to where you want to be?

MR. HALE: Currently, right now, we're staying within the existing methodology and the existing core design for Unit 3 and Unit 4. That's the limitations we're staying with --

MR. O'FARRILL: What we're seeing is that some of the core design limits that we're going to have to live with from cycle to cycle are going to be a little more restrictive in order to accommodate the impact of this, at least in the interim.

CONSULTANT WALLIS: Can I ask Westinghouse when you do your statistical analysis for LOCA, you have burn-up as one of the variables, don't you?

MR. FREPOLI: Yes.

CONSULTANT WALLIS: So TCD would figure in that?

MR. HALE: Yes, exactly. And that's really, in fact, that's where you see the big effect --

CONSULTANT WALLIS: And it looks here as if it's worse than zero burn-up, which you know. Presumably, you know that value. At zero burn-up, this slide here says zero burn-up is the worst case for --

MR. HALE: For average fuel --

CONSULTANT WALLIS: -- temperature?

MR. HALE: Yes. What you see is you have a curve that goes this way on average temperature with burn-up. The curve is the same shape, but it's higher. But still the beginning of life point is still high as the highest average --

CONSULTANT WALLIS: And you know that. You know the beginning of life, presumably, better than you know the --

MR. HALE: Unfortunately, a lot of the events are based on that beginning of life temperature, so they're not impacted by the analysis. The ASTRUM analysis, however, looks at average temperature with burn-up, and that's why you're seeing the effects with peak clad temperature.

CHAIR SHACK: When is this integrated analysis going to be done?

MR. HALE: Our target is to complete the analysis by the second week of January, so it would be available to, hopefully it will give the staff a chance to review what we've provided, and we'll be able to discuss it at full committee.

CHAIR SHACK: You might have a difficult time if we didn't have it at full committee.

MR. HALE: Understood, understood. That's why it's our target.

MEMBER ABDEL-KHALIK: Any plans to take advantage of proposed changes in 50.46(a)?

MR. O'FARRILL: Well, you mean right now or in the future?

MEMBER ABDEL-KHALIK: You know, as part of this investigation, you've done some calculations that you have not reported.

MR. O'FARRILL: I'm not aware of any calculations we have done --

MR. FREPOLI: This is Cesare Frepoli, Westinghouse. We're not crediting any benefit from the 50.46(a) at this point.

MEMBER SIEBER: This issue is not unique to Turkey Point, right?

MR. HALE: No, it is not. It is not unique. In fact, I believe the staff is looking at generic communication on those from --

MEMBER SIEBER: Well, there already was one, right?

MR. HALE: Right.

MR. PARKS: Yes, this is Ben Parks in Reactor Systems. Again, we just this morning released Information Notice 2011-21 describing and

communicating to the industry basically what we observed last week and informing them that they may need to do some further assessment to figure out what the error is in their ECCS evaluations and basically follow 50.46(a)(3) reporting requirements to us.

MEMBER SIEBER: Did you bring a copy of notice this afternoon?

MR. PARKS: I don't have one now, but I can certainly get one.

MEMBER SIEBER: Yes, after. Thank you.

CONSULTANT WALLIS: On this large-break LOCA, do you have the break size as a variable?

MR. FREPOLI: This is Cesare Frepoli, Westinghouse, again. Yes, we sample break size and --

CONSULTANT WALLIS: The probability distribution for break size is a somewhat unknown thing. I think you're actually conservative, don't you agree?

MR. FREPOLI: Yes, it's very conservative because you assume that 50 percent is a double-ended guillotine break --

CONSULTANT WALLIS: But that's such an unusual thing. It really should be one percent or something, shouldn't it?

MR. FREPOLI: Absolutely.

CONSULTANT WALLIS: So you're being very conservative about break size, this 50.46(a) thing.

MR. O'FARRILL: Anyways, we sort of jumped to the area that had the most significant impact, which is large-break LOCA. But, nonetheless, we're still doing a comprehensive assessment in all the other areas, non-LOCA, the fuel rod mechanical design criteria, core physics, as well as other areas, containment analysis as well, and assuring ourselves that there's not, we have sufficient margin --

CONSULTANT WALLIS: It really affects radiological consequences?

MR. O'FARRILL: It really does not. And that's what the preliminary conclusion shows, minimal or no impact, in many of the areas, and we have some additional assessments in progress to finalize our assessments. Fuel power to melt is one of them, rod internal pressure cladding strain and stress, some of the more localized effects of local events, locked rotor, rod injection, rod withdrawal from sub-critical and main steam line break, and, of course, large-break LOCA. And as we had discussed, preliminary evaluations indicate we're getting acceptable results and have sufficient margin to offset the effect of thermal conductivity degradation. And we're going to

be, as we mentioned, finalizing these assessments and have them available for the ACRS prior to the ACRS.

MEMBER ABDEL-KHALIK: Will these re-evaluations be available early enough for the scheduled January meeting of the full committee?

MR. O'FARRILL: That's the intent is to have them available so that the staff can review them prior to that meeting and have sufficient time . . .

MEMBER ABDEL-KHALIK: I'm just wondering if it will be necessary to delay the full committee discussion on this, just given the timing. Because not only does the staff need time to evaluate your results, we need time to evaluate both your result and the staff's.

MS. ABBOTT: This is Liz Abbott from FPL. I just want to take an opportunity, if we could, to maybe provide some response to some of the questions that were asked earlier, as well. The first is with respect to the ATWS and the peak pressure changes associated with ATWS. Mike Watson from Westinghouse.

MR. WATSON: Yes, this is Mike Watson, Westinghouse. I think the question was for the ATWS events comparison between current and EPU, and our results for the current ATWS for the loss of normal feed event was 2717 psia and for the loss of load

event it was 2839 psia. For EPU, those results for loss of normal feed, it was 3174 psia and for loss of load it was 2960. So they go up some. The limit is 3215 psia, so we're still below the limit.

MEMBER ABDEL-KHALIK: The methodology hasn't changed, just the result?

MR. WATSON: I don't believe so. Is that correct, Ed?

MR. MONAHAN: That's correct. It did not change.

MR. WATSON: Then the other one I wanted to answer was the question on the MTC for end of cycle, and the target point is inline with other plants. I think the Turkey Point value is negative 41, and the range we've looked at in looking at other plants for Westinghouse is anywhere from negative 32 to a negative 62 range, so 30 points is pretty much inline with the other ones.

MEMBER ABDEL-KHALIK: But the negative 62 is an assumed boundary for the range that you looked at or is it a real boundary for -- there's a plant out there with an MTC of minus 62 at the end of cycle?

MR. WATSON: I think that's the tech spec range, right? That's the values of the tech spec, you know, using our analysis, that we analyzed.

MEMBER ABDEL-KHALIK: Okay.

MR. WATSON: And the actual MTC of the plant is going to be lower than that, but that's the conservative . . .

MR. ROMANKO: This is Kim Romanko from Westinghouse, getting back to you on the question of the effect of tube amplitude for FIV due to tube thinning. It was looked at. It's not significant. The more significant contributor is to be the density and the velocity of the fluid as it enters the tube bundle.

MEMBER ABDEL-KHALIK: What is not significant? I mean, if you're talking about a 20 mill reduction in thickness, that's a significant fraction of the thickness. I would imagine that that's --

MR. ROMANKO: That's for local thinning due to AVB wear or, you know, plugging limit.

MEMBER ABDEL-KHALIK: Right.

MR. ROMANKO: We would not look at that in our analysis. What we would look at would be the effect, if anything, due to erosion/corrosion allowances, which are relatively small.

MEMBER ABDEL-KHALIK: What are they?

MR. ROMANKO: Erosion/corrosion is about

three mills total over the life of the plant. We've used it for 40 years. It's also applicable for 60 years. The local thinning, we do not look at that from an analysis standpoint.

MEMBER ABDEL-KHALIK: And that depends on where the thinning location is to that boundary condition in the calculation?

MR. ROMANKO: That is correct. And if there is an effect, what that would, what would end up happening would be you would make it an increase in the wear rate. That would come out during the inspections, tube inspections. If you increase your amplitude, you're increasing your stresses, the force on the tube. That may accelerate your wear, but that would be discovered when the tubes are inspected.

MEMBER ABDEL-KHALIK: No, but, I mean, without getting off the subject, we're talking about vibration amplitudes.

MR. ROMANKO: That's correct.

MEMBER ABDEL-KHALIK: We agree that, you know, you can't assume 20 mill erosion over the entire length of the --

MR. ROMANKO: No.

MEMBER ABDEL-KHALIK: -- tube. Okay. You're limited by three mills. But we're talking

about local thinning. Depending on where the local thinning is relative to your boundary condition for the vibration calculation --

MR. ROMANKO: Yes.

MEMBER ABDEL-KHALIK: -- that will impact your vibration amplitude, and the question is what do you assume there? Is that included?

MR. ROMANKO: That is not included in the analysis. That is correct.

MEMBER ABDEL-KHALIK: So when you say the effect of thinning on tube vibration is insignificant, what is that based on then?

MR. ROMANKO: That's based on the overall thinning due to erosion/corrosion, erosion/corrosion allowances. We do not look at the effect of reaching the plugging limit in a very local region, be it circumferential or opposing points such as at the ABB locations.

MEMBER ABDEL-KHALIK: And the reason you don't look at it is because what? I mean, it's reality, isn't it?

MR. ROMANKO: Yes, it's reality. Most of the thinning that we would see would be at ABB locations, which is tube-end wear. You still have a majority of the tube intact. You would get just wear

at the ABB locations. You still maintain, essentially, the integrity of the tube, the strength of the tube.

CHAIR SHACK: I think you could argue that it does increase the vibrations. Your bigger problem is the wear.

MR. ROMANKO: And that's going to be --

CHAIR SHACK: If it's going to die by one or the other, it's going to die first by wear if it's wearing that fast to thin that much.

CONSULTANT WALLIS: But the vibration would bend it more where it's weakest.

CHAIR SHACK: If you're wearing away at that kind of a rate, you have a bigger problem than the flow-induced vibration that might be associated with that. It's the wear that's going to be the problem. It may make the wear rate even a little bit worse, but it really is wear that's going to be the problem.

CONSULTANT WALLIS: If you have a weak point and the thing is vibrating, that's where it's going to feel the most effect. So it may be should be analyzed more than it's been done so far.

CHAIR SHACK: No, but the question is whether you look at the failure as a fatigue-limit

failure or as a wear rate --

CONSULTANT WALLIS: Well, they work together, don't they?

CHAIR SHACK: They work together, but you can't measure the vibration amplitude with any kind of NDE, but it can measure the wear rate. And the question is is that enough? If the failure is going to occur at the wear rate location, then he's inspecting the right location and he's seeing the damage that he needs to see, whether it's being amplified by the vibration or not.

MR. ROMANKO: And if it's a question of fatigue rate -- again, this is Kim Romanko, Westinghouse -- we've done studies of tubes at ABB locations to see how much wear you had to see before you ended up with an issue with fatigue, and we're talking through wall and beyond.

CONSULTANT WALLIS: Through wall and you've already got a problem.

MR. ROMANKO: Through wall. This is at ABB, so you're only wearing at the two sides. It's not completely around the tube. So these 20 mills that we're talking about or 40 percent through wall will not lead you to a situation where you will fail and fatigue. So this is something that would be

picked up during the inspection process.

MR. HALE: I think it's important to note that, you know, one of the reasons we went through and provided this information is to show that Turkey Point is not going to be an outlier relative to current operating experience for inspection and plugging, as appropriate, per our tech specs. And there's nothing to indicate, at least in the plant operating experience, there's been a major issue with this with Westinghouse design. In that exercise with the committee for Point Beach I think was focused on that to demonstrate that Turkey Point is not an outlier in terms of what are going to be the exciting functions that's going to cause vibration and that sort of thing, and we're doing all the appropriate inspections to identify an issue if one occurs.

MS. ABBOTT: This is Liz Abbott from FPL. We also had a question about the spent fuel pool and the time to boil off to the top of fuel, how has that changed from current plant conditions to EPU conditions. Currently, the limit is 44 hours estimated, and under EPU it will become 37 hours.

We were also asked, you know, how we manage the spent fuel capacity and do we have the capacity for two offloads available. Currently, in

both spent fuel pools, we have the capability for three offloads, as well as our normal refueling outage. So it's on the order of 450 to 500 cells that are available for that.

We do have implemented dry storage available for both facilities, so that's part of our fuel management plan is to assume that we're able to maintain, you know, storage space for offload. And we schedule and implement dry storage campaigns in order to maintain, you know, that margin.

The last question I'd like to try to address is we were asked what the, how many loss of offsite power events we've had since 2000. And it appears that there's two, one in 2000 and one in 2005. They were both Unit 4 events, as it turns out. But there were two events.

CHAIR SHACK: Wasn't there another one in 2008?

MS. ABBOTT: We did have an event in 2008 that did result in a dual unit trip, but we did not lose offsite power. It was a grid disturbance event, but we did maintain the offsite power.

MR. HALE: There was one other question we wanted to address regarding the upper-shelf energy. Rudy, could you run through that?

MR. GIL: Yes. Rudy Gil with FPL, and there was a question -- that is correct as was stated in that there were the upper shelf to intermediate shelf and the intermediate shelf to lower shelf did not meet the 50-foot pound requirement. So even before the EPU calculations, that had been addressed using the equivalent margins analysis in order to ensure that we're within the Appendix K requirements. That has been addressed and was re-reviewed including the EPU numbers. We had been using that method even before EPU.

MEMBER SIEBER: Okay. And the staff, as I understand it, it's in their SER, has reviewed that equivalence analysis and say you meet the criteria, even though you don't meet the 50-pound minimum?

MR. GIL: Yes, that analysis has been previously reviewed.

MEMBER SIEBER: Well, the staff can tell us this afternoon that they agree with that. Thank you.

MEMBER ABDEL-KHALIK: I'm keeping track of outstanding responses. I guess there are two things still remaining. One is how much degradation in the aux feedwater flow, and the other one is historical data on safety valve setpoint tests.

MR. HALE: That completes the FPL portion. I don't know if there's any additional questions.

CONSULTANT WALLIS: On your acronyms, this is not an important point, but you explain everything with words, and this thing called K-effective, which is simply defined as K-effective. I assume you're talking about a neutron multiplication factor. You're not talking about an effective conductivity.

MR. O'FARRILL: No, it is neutrons.

CONSULTANT WALLIS: Thank you.

MR. HALE: All right. Well, I thank you for your time. We appreciate it.

CHAIR SHACK: If there are no further questions, I think we'll break for lunch until 1:05.

(Whereupon, the foregoing matter went off the record at 12:03 p.m. and went back on the record at 1:05 p.m.)

CHAIR SHACK: We are back into session. Mr. Parks or Mr. Paige?

MR. PAIGE: Yes. Before we turn it over to Ben and Sam, there was a question before lunch regarding the use factor and if the staff agrees with the calculation of the reviewers in the room, and we can address that question at this time.

MR. POEHLER: Good afternoon. I'm Jeff

Poehler. I'm a senior materials engineer in the Vessel Internals Integrity Branch. And I understand there's questions on the upper shelf energy analysis. I guess is the question just whether we agreed with their calculations, or were there other questions?

MEMBER SIEBER: Well, it goes beyond that. I would like to know not only if you agree with your calculations, the SER says you do, but how you went about confirming that the applicant's position is justified when the use factor is below 50.

MR. POEHLER: Yes. With regard to the upper shelf energy analysis for Turkey Point, we had previously proved what's known as an equivalent margins analysis, which is permitted by 10 CFR 50, Appendix G, if they can't meet the minimum of 50-foot pounds. And we had reviewed the methodology and approved it in the context of the license renewal, the reviewed license renewal application. So, essentially, for the power uprate, it was basically the same exact methodology. The only changes were in the fluence, and so they just re-did the calculations for the fluence --

MEMBER SIEBER: Which is --

MR. POEHLER: For our review, we did confirmatory calculations, basically checking the

inputs and just duplicating the calculations to ensure that we agreed with their calculations.

MEMBER SIEBER: But the increase in fluence for the remaining period of operation, which was about ten percent, right? That caused the use factor to become below 50. And so another computation had to be made both by the licensee and the staff to confirm it that says, I think the use factor eventually turned out to be something like 48, which is close but not quite the right number. And I just need to know what calculation you performed, what answer you got, and why is that answer justified with regard to the being less than the 50-foot pounds?

MR. POEHLER: I think you said something about ten percent. I didn't quite hear what you said. What was the ten percent?

MEMBER SIEBER: The fluence, with the power uprate, there's an increase in fluence to the reactor vessel walls, and I think it's just one weld was below the use factor of 50 percent.

MR. POEHLER: Right. That's correct.

MEMBER SIEBER: And so my question is what method did you use to justify the fact that the applicant, in the ordinary course of the calculation, did not meet the minimum of 50?

MR. POEHLER: Well, they weren't meeting 50 before. I think even before license renewal they had projected that they weren't going to meet 50.

MEMBER SIEBER: Okay.

MR. POEHLER: And so they already analyzed that, and they analyzed it for license renewal and they analyzed it out to 48 effective full power years, which they also did for power uprate.

MEMBER SIEBER: Okay. And what kind of analysis did they perform?

MR. POEHLER: It's basically an elastic/plastic fracture mechanics analysis. It's pretty standard for the type of analyses that are performed for equivalent margin analyses. And, basically, for this material and for a lot of the welds and the vessels fabricated by B&W, it didn't have good data on the initial upper shelf energy, so that was the root of the problem. And also they were, they just used an assumed value for the initial upper shelf of 70 and using the normal techniques of Reg Guide 1.99, Rev 2, it projected to less than 50 for several of the welds, at least this one weld in Turkey Point.

But, basically, the methodology they used was approved generically back in the early 90s by the

staff and was developed by B&W. And, basically, they develop a resistance curve for the fracture toughness, which there was some testing done but then they developed a model to correlate. So if you don't have test data for a particular heated material, you can use the copper and fluence to predict what the toughness is going to be. And then you basically develop with that model a resistance curve of J integral toughness versus crack extension, and you compare that to the applied J value, and there's basically a couple of conditions it has to meet as far as the applied versus the resistance curve. And they met those conditions, which they're actually, as far as how you analyze it, Appendix K of Section 11 of the ASME codes gives the standardized methodology for that. So that covers how you evaluate it. It doesn't address the resistance models. So B&W had their own vendor-specific resistance model, which we had approved in the early 90s. And they were still using the same model for this revision of the, for this plant-specific equivalent margins analysis.

So it's basically just a matter of changing the fluence and seeing how that changes. And they evaluate the fracture toughness at a particular crack extension, which is 0.1 inch.

MEMBER SIEBER: Now, it's also my understanding and you can correct me if I'm not correct on this, but in a number of the early reactor vessels, the exact composition and the material, including obtaining samples coupons for later testing was not particularly accurate. In other words, it's ample for testing and the composition that was specified didn't come from measurements of the actual material in the vessel. It was, at the time, in the 1970s, claimed to be similar to but not identical to or being an offspring to the actual material of the vessel; is that correct?

MR. POEHLER: In this case, there weren't any issues with the chemical composition. The only -- basically, the unknown was the initial upper shelf energy because that wasn't a requirement at the time the vessel was built. So the copper and fluence were none for this particular weld or the copper and nickel I guess. It relates copper for the upper shelf model.

MEMBER SIEBER: You knew it well enough to be able to feel comfortable with the calculations that you made?

MR. POEHLER: Yes.

MEMBER SIEBER: Okay. I guess that's good enough --

MEMBER ARMIJO: In this equivalent margins analysis that was performed, there's an acceptance criterion of some sort. I'm not familiar with it. At EPU, does Turkey Point meet that acceptance criterion barely, with flying colors, or to what extent does it meet the acceptance criteria?

MR. POEHLER: It met the acceptance criteria by a large margin.

MEMBER ARMIJO: Okay.

MR. POEHLER: Basically, I think it was a margin of about three to four times the value at 0.1 inch crack extension for the resistance curve divided by the applied curve.

MEMBER ARMIJO: Okay, thank you.

MEMBER SIEBER: Yes, I think that answered my question. Thank you very much, sir.

MR. POEHLER: You're welcome. Thanks.

MR. PARKS: Good afternoon. My name is Benjamin Parks, and I'm here with Sam Miranda in reactor systems and we're going to talk to you about the safety analysis. I apologize. Dr. Ward is not here to talk to you about the boric acid precipitation calculations that he did. I am familiar with his review. I will cover his slides. I don't mirror his level of expertise, and so I'll try to answer any

questions that you have but I may need to defer and get back to you once we can get back in touch with Len. He had an emergency and he couldn't join us.

Today, we're going to cover our review procedures and talk about our focus areas. We'll talk about the audits that we did between the time we finished up our safety evaluation and now. We will cover our review results and recommendations and present our conclusion.

I don't think that anything was out of the ordinary for how we covered this review, but Turkey Point is a plant that precedes the GDC, and so, you know, with that in mind, we had to adapt RS-001, which is based on the Standard Review Plan and that is based on the GDC that are in effect now. So we rewrote the regulatory evaluation based on Turkey Point's GDCs. You know, the licensee and the staff both gave very careful consideration to this paragraph in RS-001 which says that we review plants against their design bases and, you know, without intent to back-fit.

In some cases, we did have to ask the licensee for information that we felt was necessary to make our finding for EPU, even though it may have related to an event that was not in their licensing basis. And so for those events, and we'll step

through those, we'll explain why we felt we needed the information and what we did with the information once we got it.

I'd like to explain, just very quickly, administratively how we accomplished our review, and then I will step into the more interesting part of our presentation, which is the technical stuff. And I'll cover the main steam line break. I'm sorry. Actually, Sam is going to cover that and the feedwater line break. We will cover the inadvertent opening of a primary relief valve and also the boron dilution event, which is not on here but we will talk about it. And the emergency core cooling system evaluation, and that includes the LOCA analysis and the boron precipitation analysis.

Basically, we had a challenging year, but we wanted to make sure that we gave this particular review the appropriate level of effort. So we added some reviewers. You know, when we did Point Beach last year, we used mainly three reviewers. And in this case, we relied on the help of nine reviewers, so we got some extra eyes in here and, you know, we did a lot of efforts in parallel.

Basically, to get our review completed, what we did was we resolved our open items once we

completed our safety evaluation, and that helped us kind of reduce the exhaustive use of RAIs where we ask a question and the licensee gives us an answer but it doesn't quite satisfy the staff, and so we go back and ask another one and ask again. What we did instead was we completed our safety evaluation so that we were better able to say this is what we really need you to do. The licensee was able to understand that and get back to us in a much more satisfactory manner. So we'll cover that as we step through the events.

I'm going to turn it over now to Sam to talk about the main steam line break.

MR. MIRANDA: This first slide I guess can be included among the administrative matters. This is very basic information. Steam line break, main steam line break is an ANS Condition 4 event, it always has been, and it's treated as such in RS-001. However, for Westinghouse plants, the main steam line break does meet ANS Condition 2 criteria.

So this time around in this review I took the liberty of applying the Condition 2 acceptance criteria to main steam line break. This is not a change in the licensing basis. It still is a Condition 4 event. However, if the licensee can show by analysis that the main steam line break meets

Condition 2 criteria, for example meeting the fuel clad integrity criteria, then it makes for a better tighter comparison when evaluating the steam line break by looking at the Condition 2 criteria. So that's what we did, but we reiterate that in the licensing basis for Turkey Point, as all other plants, the main steam line break is a Condition 4 event.

And what that essentially translates to is the Condition 4 criteria are way up here, you know, core geometry that's coolable and offsite dose limits are met, etcetera, etcetera. But the results don't come anywhere near that, so we look at the more restrictive Condition 2 criteria.

The main steam line break presented by the licensee had a hot full power case, and that was analyzed for a 0.65 square foot break. This was determined to be the limiting break for the hot full power case. It's the largest break that goes not result in a reactor trip on overpower delta T. And the overpower delta T trip is designed to protect against fuel center line melting, so that's why we have the kilowatt per foot limit there, 22.72, and it's below that.

MEMBER ABDEL-KHALIK: What's the trip setpoint for this event? Which signal trips the

reactor in this case?

MR. MIRANDA: In this case, the trip comes from low steam line pressure or overpower delta T.

MEMBER ABDEL-KHALIK: You mean it doesn't come from narrow-range low steam generator level?

MR. MIRANDA: Overpower delta T gets there first, so you have, basically, two break sizes. The larger break sizes will trip on the low steam line pressure, and then the smaller steam line break sizes will trip on the overpower delta T. So this is the largest one that trips on the overpower delta T, and this is the one that's sized to test the adequacy of the overpower delta T trip.

MEMBER SKILLMAN: How many cases were run to finally settle on the 0.65 square foot, please?

MR. MIRANDA: I don't know offhand. That's a Westinghouse question. I'd say a number of them.

MR. MONAHAN: Yes. This is Ed Monahan from Westinghouse. We start at a very small break, like a 0.1, and incrementally increase it by, I think in this case it was 0.1 square feet until the trips come in, as Sam discussed. So I'd say we ran probably ten cases or so, somewhere around there.

MEMBER SKILLMAN: Thank you.

MR. MIRANDA: And then once the trip occurs, in the hot full power case, we've determined already that there's no fuel center line melting, there's no clad integrity challenge. When we move into the hot zero power break, and this is the limiting cool-down event. This is the one where you have the trip early in the transient. It occurs at no-load conditions, and the cool-down causes the core to return to critical and generate power. And since the trip has already occurred, there's also an assumption that the most reactive rod is stuck out of the core. So in the region of the stuck rod, there are very high hot channel factors, and there is a possibility of DNB.

So we look at the hot zero power case for DNB concerns, and a 1.4 square foot break is the largest possible break in a steam line. It reflects the fact that the flow will choke at the flow measuring venturi, which is a 16-inch venturi for a 1.4 square foot. And in that case, there have been, the minimum DNBR was greater than the limit 1.4. And this is the Condition 2 acceptance criteria that I was referring to earlier. Turkey Point, as well as other Westinghouse plants meet the Condition 2 criteria.

Now, there was a particular design feature

of Turkey Point that I questioned. Turkey Point being an older plant, they have what Westinghouse calls the old steam break protection system. And under this system, the reactor trip, safety injection, and steam line isolation occur on a coincidence of high steam flow and low pressure or T-ave, whereas the newer plants have simply low steam line pressure.

So for a large break, for a 1.4 square foot break, it makes no difference. You reach the low steam line pressure condition, and you have in coincidence with that the high steam flow condition, so you get steam line isolation and safety injection. However, for the Turkey Point system, if you have a smaller steam line break, it's possible that you won't achieve the high steam flow condition. And if you don't have the high steam flow condition, you don't have steam line isolation.

So I asked the licensee, well, what is the largest break size possible that will not actuate steam line isolation on the high steam flow condition? And they determined that, through a series of runs, to be 0.9 square feet. And at our audit earlier this month, Westinghouse showed us the results of the analyses for the 0.9 square foot break, and the minimum DNBR was well above 1.4.

In this case, the steam line isolation would have to occur by manual operation, so it would take a while. And I was concerned also about steam generator dry-out in that condition, and I calculated it just on the back of the envelope something like 30 minutes to dry out the steam generators without steam line isolation. Westinghouse did that case, and their number came up with 40 minutes. And that's a very conservative analysis because it doesn't include the effect of your feedwater being added to the steam generators. And then, finally, I asked --

MEMBER ABDEL-KHALIK: Does it make any difference whether this break is inside containment or outside containment? What is the trip setpoint for containment pressure?

MR. MIRANDA: I don't know that offhand. It's usually about --

MEMBER ABDEL-KHALIK: It's very low.

MR. MIRANDA: Yes, 5 psi or something like that.

MR. SHAFER: This is Sam Shafer, Florida Power and Light. An actual containment trip for safety injection is four pounds.

MEMBER ABDEL-KHALIK: Right.

MR. MIRANDA: Okay. Let me say something

about that. I think your question stems from the titles of the analyses. They say steam line breaks occur in inside and outside containment, and that's an archaic term.

MEMBER ABDEL-KHALIK: I mean, whether it happens inside or outside containment, you know, will determine whether or not the containment pressure setpoint comes into play.

MR. MIRANDA: That's right. And it doesn't. The low steam line pressure comes much, much sooner. The inside and outside containment stuff, probably we should eliminate that because in the old days, back in the 70s, the flow measuring venturi was located in the steam line, so it was possible to have a break upstream of the flow measuring venturi and you had something like a four and a half square foot break. And since the flow measuring venturi was upstream of the steam line isolation valves, it was always inside containment. So the inside containment break was another way of saying you had a four and a half square foot break.

Since then, they've moved this venturi to the outlet nozzle of the steam generator, so now it's not possible to have a break that size. So an inside break has no meaning anymore.

MEMBER ABDEL-KHALIK: Well, that's your opinion, but that's okay.

MR. MIRANDA: There are other aspects, but the inside and outside breaks refer to the break size in those days. There are other things. Containment pressure response, of course, and radiological effects as well. But inside and outside break was strictly another way of saying a 1.4 square foot, that was the outside break. Four and a half square foot was the inside break.

MEMBER SKILLMAN: Well, wait a minute. In the words of our great philosopher Yosemite Sam, not so fast there, partner, okay?

MR. MIRANDA: Okay.

MEMBER SKILLMAN: I'm with Dr. Khalik. Thank you for your explanation about the history, and I do understand that. But the other side of this is a break inside containment, you're losing more energy with this power uprate. And so your focusing on fuel and DNBR. I'm not so sure that Dr. Khalik might have been going after something more important or as important, and that is the containment question. So are you limiting your discussion simply to fuel conditions, or are you going to talk a little later about inside containment pressure and the consequence

of relieving this greater amount of energy to inside containment for the inside containment break?

MR. MIRANDA: The inside containment break is 1.4 square feet.

MEMBER SKILLMAN: Okay. Is the pressure the same as before the EPU?

MR. MIRANDA: Yes, the steam -- you mean the steam pressure? Yes, it's the same because it's conducted at no-load conditions --

MEMBER SKILLMAN: No, the containment pressure.

MR. MIRANDA: The containment pressure? You mean where does it rise after the --

MEMBER SKILLMAN: Right.

MR. MIRANDA: -- steam line break?

MEMBER SKILLMAN: Inside containment.

MR. MIRANDA: Inside containment?

MR. HALE: We can speak to that.

MEMBER SKILLMAN: I would like to hear that because I think that's where Dr. Khalik might have been going.

MR. HALE: Yes. Certainly, Sam's evaluation is focusing on core response and DNBR. The containment analysis for main steam line break, our design pressure is about 55 psig, and the steam line

break analysis I believe is around 53.9, something like that.

We did have to make some changes in terms of design. One of the changes we made which was reflected was we reduced our tech spec on normal operating pressure from 3 psig to 1 psig. Historically, we've been able to stay well below the 1 psig, so that was a change we made to buy back, I would say, some of the margin.

MEMBER ABDEL-KHALIK: Pressure margin.

MR. HALE: But the main steam line break is over a pound with regards to design margin, you know, the actual main steam line break analysis for containment pressure versus the containment pressure design.

MEMBER ABDEL-KHALIK: So the 53.9 corresponds to EPU conditions --

MR. HALE: Right, exactly.

MEMBER ABDEL-KHALIK: -- with the change in tech spec for the normal pressure in the containment?

MR. HALE: Correct.

MEMBER ABDEL-KHALIK: What was the original peak pressure for the main steam line break before EPU?

MR. HALE: That's a good question.

MEMBER ABDEL-KHALIK: You can give us that information later.

MR. HALE: Yes. We can get that easy --

MEMBER ABDEL-KHALIK: Thanks.

MEMBER SKILLMAN: Sam, thank you.

MR. MIRANDA: I'm sorry. I was only looking at the core --

MEMBER SKILLMAN: I understand.

MR. MIRANDA: -- response.

MEMBER SKILLMAN: And I threw a monkeywrench into that, but thank you.

MEMBER ABDEL-KHALIK: I'm trying to get there, but that's okay. Thank you.

MEMBER ARMIJO: Before you leave, what is your expectation will happen in the core if you had a main steam line break? You won't get the fuel melting or incipient fuel melting. You won't have DNBR. But would you expect to have any fuel failures or a certain number of fuel failures?

MR. MIRANDA: I don't expect, I don't expect any significant fuel failures because the minimum DNBR meets the 95/95 limit.

MEMBER ARMIJO: Is that the only mechanism for fuel failure that you consider DNBR or fuel

melting?

MR. MIRANDA: Well, there have been some studies which I'm not really familiar with, but the depressurization in the core, it's possible you could have some fuel damage due to the pressure differential that develops on the clad.

MEMBER ARMIJO: How about pellet-cladding interaction fuel failures? Stress corrosion cracking from fission products in the stress? You haven't evaluated that? That's not part of your --

MR. MIRANDA: We haven't evaluated that, but I know those things have been looked at many years ago.

MEMBER ARMIJO: Yes, but it's not part of your evaluation that has --

MR. MIRANDA: No, not anymore. I mean, those questions were resolved. No, I can't say anymore about that.

MEMBER ARMIJO: Okay. But during this transient, there's stress on the cladding?

MR. MIRANDA: It could be, yes, just because of the steep depressurization.

MEMBER ARMIJO: The pellet is getting very hot. It's going to reach something close to 22 kilowatts per foot at some locations. It's pretty hot

at those locations. There's stress on the cladding, and really there's little or no external pressure or not too much, so you'll have a lot of tensile stress on the cladding and, depending on your fuel burn-up, you have fission products there. And the question I had is have you evaluated any kind of a degree of risk of failing the fuel due to PCI? It doesn't take very long at those high stresses if you've got enough fission product.

MR. MIRANDA: I don't know how long. I know that for the hot full power case, which is the one that would approach the linear heat rate limit, the reactor trip comes very early, within ten or twenty seconds.

MEMBER ARMIJO: Yes, if it truly trips within ten or twenty seconds. But if it takes a few minutes you're in trouble and there's experiments that have been done to demonstrate how sensitive that is. But if your timing is really that short then --

MR. MIRANDA: It's short, and the overpower delta T trip upon which the smaller breaks will trip, that's a lead lag signal. It also comes in very quickly, even for a small break, because of the dynamic time compensation.

MEMBER ARMIJO: Okay, thank you.

MR. MIRANDA: I also asked for a credible break. A credible break is the -- oh --

MR. RODACK: Excuse me, if I may. I'm Tom Rodack from Westinghouse. I don't know the details of the fuel design analysis, but we do satisfy the one percent strain criterion in our design analysis looking at transients. I just don't know specifically for steam line break.

MEMBER ARMIJO: But the one percent strain, you know, if you do have a PCI phenomenon, it fails at much, much, much less than one percent strain to cause it. I think the best response I got was that the transient is over in a few seconds, and if that's the case then I think you have a good story. If it isn't the case, I'm not so sure.

MR. MIRANDA: One case that is not typically analyzed is the credible break. The credible break is the inadvertent opening of a secondary side valve. It's considered a Condition 2 event, unlike the other steam breaks. And it's not typically analyzed because the large break has been found to be the limiting case. However, I wanted a credible break analysis in this case because of that old steam line break protection system and the fact that the credible break will not be large enough to

cause the high steam-flow condition that leads to steam line isolation.

So during the audit, Westinghouse provided results of a credible break analysis, and it indicated that, in that case, even without the steam line isolation, the core did not return to critical. So that was not a problem.

MEMBER SKILLMAN: Sam, for that credible break, did you use the end-of-life moderator temperature coefficient for the reactivity that comes with the cool-down with the blow-down that goes with the steam line break?

MR. MIRANDA: Yes, the credible break is conducted just like the hot zero power main steam line break at end-of-life conditions and the most negative moderator temperature coefficient.

MEMBER SKILLMAN: Thank you, Sam.

MR. MIRANDA: The feedwater line break is a Condition 4 event, and it was not part of the Turkey Point design basis. There are a number of Westinghouse plants that do not have the feed line break in their design basis. We asked for it because it is a design event. The feed line break analyses are used to verify that the auxiliary feedwater system is capable of removing the decay heat and it's also

used to verify that the steam generator low-level trip setpoint provides effective protection. And this has to be also conducted under hostile environment. So, for example, if you have a feed line break inside containment, it could heat up the reference leg that's used to measure steam generator water level and cause a false high reading, in which case you wouldn't get a low-level trip.

And the feed line break is conducted over the long term. There's usually a loss of offsite power assumed to go with this. And during the course of the feed line break, the reactor coolant system temperatures are tracked to be sure that saturation conditions are not reached in the reactor coolant system. And in this case, the feed line break analysis provided by FP&L showed that there was adequate sub-cooling margin in their reactor coolant system. And this verifies then that there's no steam generator in the reactor coolant system, and you don't have to worry about effects such as steam binding when steam might collect at the top of the U-tubes in the steam generator and might block natural circulation or later on in the transient.

And it is a transient that will produce very high pressures. It will open the pressurizer

safety valves. It will fill the pressurizer. You'll pass water through the safety valves. But the criterion here as a Condition 4 event is that the core remain covered in a coolable geometry. Those conditions, those criterion were satisfied.

So this is an example of what Ben referred to earlier. This is an outside design basis event for Turkey Point. It was not in their FSAR, it was not in their EPU application, but the staff wanted to see this analysis to check for those things.

MEMBER SKILLMAN: Let me ask a question, please, on feedwater line break. What consideration was given to the momentum loads to the internals of the steam generator on feedwater line break?

MR. MIRANDA: Are you worried about some tube damage?

MEMBER SKILLMAN: Yes, sir.

MR. MIRANDA: None that I know of. We didn't look at that in this review.

MEMBER SKILLMAN: Okay, thank you.

CONSULTANT WALLIS: So what happens before one hour? Did I miss something with --

MR. MIRANDA: Yes. Usually, it takes a while for the decay heat to be removed fully.

CONSULTANT WALLIS: In other words, it

doesn't go dry?

MR. MIRANDA: No, no. We have feed line isolation and steam line isolation. No, what happens is you assume there's a single failure in the auxiliary feedwater system, so you're operating with basically one auxiliary feedwater pump. It's not capable of removing all of the decay heat, and temperatures and pressures are rising during that time, the pressurizer fills, safety valves open, and this continues until finally the decay heat generation drops below the aux feed heat removal capacity, and that takes about an hour.

MR. PARKS: I'll speak to the inadvertent opening of the primary relief valve. Sam and I actually worked together. Sam's going to jump in from time to time to add his perspectives, as well. We requested the inadvertent opening of the relief valve analysis to validate requested changes to the over-temperature delta T setpoint equation. There are a couple of terms in that setpoint equation. One of those compensates the trip setpoint for the reactor coolant system pressure so that the setpoint changes when the pressure changes. So it's there for DNB protection. As the RCS depressurizes, the trip setpoint needs to become a bit more aggressive to trip

the reactor.

So the licensee requested to change that coefficient, and so it was our opinion that we needed to see some analyses to validate that those setpoints were correctly chosen. What we got in response to that was an analysis demonstrating that there was ample DNB margin. I believe that the result was something around 1.6, something to that effect was the minimum DNB.

The interesting thing was that, at the tail end of the transient, the staff typically looks for an indication in the transient plots that the plant is stabilizing. And in this case, there was very strong pressurizer insurge at the end of the event, and so that gave us cause to question what was happening with the plant. I should say that this analysis was, actually, it was assumed opening of the safety valve, so it's a more severe transient. It's actually a Condition 3 event.

CONSULTANT WALLIS: You said pressurizer insurge?

MR. PARKS: Pressurizer insurge --

CONSULTANT WALLIS: Because the screen says pressurized insurge. I didn't know what that meant.

MR. PARKS: I'm afraid that Microsoft was trying to be smarter than me.

CONSULTANT WALLIS: So it's into the pressurizer?

MR. PARKS: Yes.

CONSULTANT WALLIS: Okay.

MR. PARKS: It is not a pressurized insurge. It's, you know, the system pressure.

MR. MIRANDA: Maybe I should jump in at this point. Westinghouse analyzes this event as a Condition 2 event, and it is a Condition 2 event. The pressurizer power-operated relief valve could open as a result of a failure of, say, a pressure sensor. It could fail high, so you might have the pressure sensor, control pressure sensor that's used for pressurizer pressure control. It fails high, causes the power-operated relief valves to open, and it does happen. And that's why the Condition 2 acceptance criteria applied. And what we're looking for here is protection of the fuel design limits. We can't have DNB. And the reactor protection system function that is designed to protect against DNB is the over-temperature delta T.

Now, Westinghouse analyzes this event for most of their plants. Not for Turkey Point because

Turkey Point is an older plant, and it didn't appear in their licensing basis. They analyzed this event and show that the over-temperature delta T trip is effective in preventing DNB.

And to be conservative, they assume that it's not a pressurizer power-operated relief valve that opens, it's a safety valve that opens, simply because a safety valve is twice as big as a relief valve. It's not really going to open.

MEMBER ABDEL-KHALIK: If the OT delta T trip doesn't come in, wouldn't the reactor trip on low pressure?

MR. MIRANDA: It will trip on low pressure. It will trip on other things. But what we want to do here is verify that this trip is operating as it should because it's one of the two transients that are used to set the over-temperature delta T trip equation, this one for the low pressure effect and the rod of power event for the high power effect.

MR. PARKS: So this analysis demonstrated that the fuel cladding integrity specified acceptable fuel design limit was met, that the DNB margins were acceptable, and that's one of the Condition 2 event acceptance criteria. But the results gave us cause to question their compliance with another acceptance

criterion, which is that the transient can't, without another independent event occurring, escalate into something more serious. So the pressurizer insurge would give us concern that the pressurizer may, in fact, fail if some action isn't taken to secure the plant. And if that were to happen, then one of the relief valves or a PORV may pop open, and it may be challenged to recede because it's relieving liquid water.

MEMBER ARMIJO: What is the duration of this event? How long does it last?

MR. PARKS: The duration of the events, if trips and you stop at the DNB portion of it, it's very quick. I think it was less than ten seconds, certainly less than 30 seconds. It was very quick. The duration of the event otherwise, here on this slide, basically, you know, there are a couple of things at Turkey Point. One of them is the fact that their safety injection system is cross-tied between the units, and so they have four safety injections. So eliminating single failure, there's lots of margin there. But if they all work and you are losing your RCS pressure, you start filling up your pressurizer and you do so pretty quickly. So the cases at Turkey Point that they could fill up the pressurizer in about

four to five minutes if they don't take an action to secure the plant following the hardware malfunction.

MEMBER ABDEL-KHALIK: How long does it take for the RCS to reach saturation at T-ave??

MR. MIRANDA: I don't know. Depressurization?

MEMBER ABDEL-KHALIK: Right, yes.

MR. PARKS: I believe the hot legs actually saturate in this event. The fact that the DNB remains above its limit suggests that there's no significant boiling in the core. I mean, again, it's tripped pretty quickly.

CONSULTANT WALLIS: So your insurge is all sub-cooled water or not? You could avoid some of the pressurizing?

MR. PARKS: The pressurizer has steam in it. It's saturated --

CONSULTANT WALLIS: I mean in the liquid part of it.

MR. MIRANDA: Yes, yes, that's what we saw in --

CONSULTANT WALLIS: You probably get swelling of the liquid part?

MR. MIRANDA: Core, yes.

CONSULTANT WALLIS: Because of voids in

it?

MR. MIRANDA: Yes, yes. The pressurizer level indication would go up.

CONSULTANT WALLIS: What do you mean by level? It's at the top of the water or is it the collapsed water?

MR. MIRANDA: Whatever it is, on the control board you would see the level go up, which was a problem that, you know, we're seeing at Three Mile Island that led to the operators thinking that it was okay to turn off safety injection when actually the level was going down.

CONSULTANT WALLIS: Well, the pressurizer, the core became the pressurizer. Is four and a half minutes good enough? Is that good enough time?

MR. MIRANDA: We're going to get to that.

CONSULTANT WALLIS: Oh, okay.

MR. PARKS: We were concerned about that, and so we decided to run an audit down at Turkey Point and look at this in a simulator. And we acknowledge that the simulator has not been retrofit for EPU conditions. However, we can get a sense for what the operators do. An inadvertent or pre-EPU, the operator response needs to be similar, even though their response times may be slightly different.

So we observed the mitigation strategies. A response to this event is a prompt action, which means they don't thumb through procedures. They see it, they acknowledge, they verbalize that they know what's going on, and then they act. And so we saw that the operator actually secured the plant from this event in about nine seconds. It was very quick.

CONSULTANT WALLIS: So he has a block valve or something he closes and --

MR. PARKS: In this case, it was a control failure that I believe the operator was able to close the PORV. So the PORV received a demand signal and opened, and the operator said, no, wait a minute, close it. The block valve was the next step, and I think we discussed that during the --

CONSULTANT WALLIS: The nine seconds is incredible.

MR. PARKS: Dr. Wallis, what was limiting them was discussing what they were doing at the time.

CONSULTANT WALLIS: Yes, yes. If they knew something like this was going to happen.

MR. PARKS: Well, yes.

MR. MIRANDA: They saw immediately that a pressure sensor had failed. They checked the pressure. There was no legitimate demand for a PORV

to be open, so they closed it. And if the PORV had been leaking, they had the block valve available.

MR. PARKS: So for this event, I mean, we do want to maintain our focus on Turkey Point, but, you know, just to continue the thread a little bit on four to five minutes, that is pretty quick. You know, Turkey Point is a little bit unique because it has this four-unit safety injection system, but those are centrifugal pumps with the shutoff head around 1600 psi, so you have to wait. Some plants have charging pumps for their high-head safety injection, and they can actually inject at pressure. So we don't believe that the staff has ever considered this as a mass addition type event. It's an RCS depressurization, and that's the way that we always look at it. So we are considering a generic communication about this, you know, in parallel with our review efforts here.

MR. MIRANDA: Yes. Reg Guide 1.70, the standard format and content guide for safety analysis reports, identifies two mass addition events, the control volume and chemical system malfunction and the inadvertent safety injection. And that's it, just those two. But it turns out that if we look at this event, a Condition 2 event, the inadvertent opening of a PORV, it is in the natural sequence of expected

events that the low pressurizer pressure will actuate the safety injection. So there's no other failure involved here.

And the safety injection in this case, in the context of a depressurizing RCS, is much worse or much faster event than the inadvertent SI actuation. So strictly speaking, Reg Guide 1.70 ought to be revised to include this also as a mass addition event.

CONSULTANT WALLIS: It looks like a generic thing. It's not just a Turkey Point thing.

MR. MIRANDA: Right. Turkey Point was, as Ben said, is pretty well off in this respect. They don't have the charging pumps in their ECCS. So for them, it was enough to just close the PORV. If they had the charging pumps operating, then they would have to proceed with a shutdown of the ECCS, and that would take longer.

MR. PARKS: That's assuming, of course, that the ECCS actuation signal is received. If it's this type of failure where it's as simple as closing the PORV, they may not get there. I think we need to continue working it generically.

MR. MIRANDA: Well, we're talking about two worlds here.

MR. PARKS: Right.

MR. MIRANDA: The real world, the PORV is closed in nine seconds. In licensing world, they can't do anything before five or ten minutes. Conservative licensing assumptions and deterministic analysis.

MR. HALE: If I could, to respond to the question on containment pressure. I believe it was your question on containment pressure. Oh, by the way, I'm Steve Hale, Florida Power and Light. The current containment pressure for main steam line break is 53.4 psig. What I provided you earlier was a little inaccurate. The current main steam line break for EPU is also 53.4. The LOCA analysis is 53.9. We were able to offset the changes as a result of EPU with the tech spec change I was discussing, where we lowered the normal operating containment pressure from three to one. So, essentially, there's not going to be any change in containment pressure as a result of the EPU with regards to margin.

MEMBER ABDEL-KHALIK: Because you changed tech specs?

MR. HALE: Right, right.

MR. MIRANDA: Thank you. Boron dilution is a Condition 2 event. And if we look at the Standard Review Plan, the boron dilution event should

be analyzed in all six modes. Turkey Point, having been licensed before the Standard Review Plan was published, provided analyses only for Modes 1, 2, and 6.

We asked the question, we wanted analyses for Modes 3, 4, and 5 because those are the shutdown modes. Those are the ones where you have to rely on operator action to terminate the boron dilution, you have 15 minutes to do so, and there was no analyses presented.

In response to our question, the answer we got was kind of puzzling. It said that there was no requirement for Modes 3, 4, and 5, and they refer to Reg Guide 1.70 and said if you look at that there's no explicit requirement for Modes 3, 4, and 5, that it was added later after the plant was licensed. And I checked all the versions of Reg Guide 1.70 that I had going back to 1966, and in no versions did it specify what modes needed to be analyzed.

MEMBER ABDEL-KHALIK: So the implication is that all modes --

MR. MIRANDA: All modes, yes.

MEMBER ABDEL-KHALIK: That's your interpretation of it?

MR. MIRANDA: Yes, yes. And so they

provided, Westinghouse provided the analyses for Modes 3, 4, and 5. And as a result, Florida Power and Light has decided to increase the shutdown margin from 1 percent to 1.77 percent in Mode 5 and in the lower portion of Mode 4 where the RHR pumps are in operation. And these are in the requested tech specs. So this is a case where Modes 3, 4, and 5 needed to be analyzed.

MEMBER ABDEL-KHALIK: In a dilution event when the reactor is operating, you assume the rods are in auto or in manual?

MR. MIRANDA: Yes, both. They do analyses -- in Mode 1, they could be in auto or manual, yes. And the analyses are presented for both cases. But Mode 1 doesn't really present a problem so much because you have automatic, you know, protection. It's when you get to the lower modes where you're relying on operator action and on indications that are not, they're not automatic. For example, like the source range reactor trip. The source range reactor trip is not considered to be a qualified trip because it only has two channels. And say you're withdrawing a rod in a section of the core that's away from the one detector you have operating and the other one is assumed to fail, you may not see the rod being

withdrawn.

Boron dilution, on the other hand, would cause a, more or less, uniform flux increase. You would see it even with one detector.

MEMBER ABDEL-KHALIK: So what does the increase in shutdown margin do? Just give the operator more time?

MR. MIRANDA: Yes, yes.

MEMBER ABDEL-KHALIK: How much more time?

MR. MIRANDA: Enough to get him past the 15-minute limit.

MEMBER ABDEL-KHALIK: Okay.

MR. MIRANDA: He has 15 minutes to terminate the boron dilution. So with the added shutdown margin, 15 minutes becomes available.

MEMBER ABDEL-KHALIK: Assuming dilution rate corresponding to one charging pump?

MR. MIRANDA: No, it's more than that. It's maximum charging, maximum possible charging. And in this case, in these analyses, we looked at the calculations during the audit, and these analyses were conducted, I would say, probably from the back end to the front. In other words, they determined the limits they would need to cover future reload cores, so they started with the 15 minutes and determined how much

shutdown margin they would need. And the same thing with the charging. They put in the maximum possible charging, even though things could change in the future to reduce the charging possible. They tried to come up with an enveloping analysis that would serve for the next few reloads.

CONSULTANT WALLIS: So this charging pump water is not borated?

MR. MIRANDA: No, it's assumed to be clean. Yes.

CONSULTANT WALLIS: So it's a risky thing to keep pumping it in?

MR. MIRANDA: This is another example of the real world versus the analyses. I don't think this is going to happen --

CONSULTANT WALLIS: You're assuming something which is really unlikely to ever happen?

MR. MIRANDA: Yes, yes. Boron dilution operations are usually planned, you know. So many gallons in so many minutes.

CONSULTANT WALLIS: But the consequences are not very pleasant.

MR. MIRANDA: No.

MR. PARKS: There's a lexicon in our applications. Typically, the licensee has used the

phrase "under strict administrative control." They keep an eye on it.

CONSULTANT WALLIS: This relies on people doing the right thing, and people doing the wrong thing is the usual cause of events.

MR. MIRANDA: That's one of the definitions of an AOO, an anticipated operational occurrence, is a single operator error.

CONSULTANT WALLIS: Right.

MEMBER SKILLMAN: Let me ask this, please, just so I'm clear on what this Slide 19 is communicating. In your conclusions on your staff letter, you say, "The NRC has reviewed the licensee's analysis of the decrease in boron concentration due to CVS malfunction and concludes the licensee's analysis do not adequately address plant operations in the proposed uprated conditions. The licensee must justify its charging flow assumptions in Modes 3, 4, and 5." Is this the conclusion from your -- or is the slide indicating what has been done to address this concern?

MR. MIRANDA: I think the slide is more recent, and we need to correct that.

MEMBER SKILLMAN: You need to correct this?

MR. MIRANDA: Yes.

MR. PARKS: We'll talk about this at the end of our presentation also. We left some open items in the safety evaluation. We subsequently did a couple audits. One was the simulator audit where we observed some events, and we also audited calculations in Cranberry, Pennsylvania at Westinghouse's headquarters. And during that, we verified these assumptions for charging flow because they were different for Modes 1, 2, and 6, and we found that they were still, I believe, bounding of the maximum charging flow. It was achievable. So subsequent to the issuance of our draft SE with open items, we did confirm that that was acceptable.

MEMBER SKILLMAN: Thank you. Let me go back to a question that Dr. Wallis asked, and it was about the simulation that you discussed in a previous slide in which the operators caught this in nine seconds. And the question was did they know this was coming, and I'm going to assume that this might have been scenario where they knew that this could be an event that they were going to be looking for.

Here's my question. If this were to have happened out of the blue, in other words at 4:00 in the morning, like on March 28th of 1979 in Harrisburg,

would there have been enough information so that the operators would have concluded, hey, I've had a control module failure and that is why my PORV has opened? Would there have been enough other information to tell them that?

MR. PARKS: Between now and 1979, I believe they have a lot more information in the control room to indicate --

MEMBER SKILLMAN: Oh, yes, sure.

MR. PARKS: -- what's going on, of course. What we observed was they got alarms in to say that there was a PORV open. There's a position indicator, and then there's a couple of other annunciators also that indicated. So, perhaps, yes, the operators were expecting the event. Even so, they would have been alerted and we were assured by FPL that they train on this regularly, so they know how to recognize and respond to the event. So it may have been more than nine seconds, but there's a lot of margin between nine seconds and the five minutes, I guess, operationally.

MR. SHAFER: If I may, this is Sam Shafer from Florida Power and Light. We do train on the event all the time. Multiple indications, cross indications we look at. Because it's a prompt operator action, where the reactor operator physically

sits and where my PORV controls are, the block valves are right next to me. It is literally seconds. We get the PORV opened, we get indication of pressure dropping. I've had a PORV opened, you know, instrument failure, closing PORV.

Now, if the PORV doesn't close, the immediate thing he does is go right for the block valve. In parallel, he's watching pressure come down. Not to challenge any over-temperature setpoint, at 2,000 pound decreasing we'll order a manual reactor trip. We practice it all the time.

MEMBER SKILLMAN: Thank you.

CONSULTANT WALLIS: And this is if he's not doing something else. I mean, if it occurs while he's got his mind on something else then nine seconds seems to me much too quick.

MR. SHAFER: Nine seconds could be very quick. And you're right. If he's off doing something, although he's at the controls, if he's not specifically over there he may be monitoring. But within a very short amount of time, a few more seconds.

MR. MIRANDA: And one thing I noticed when I saw the exercise, the first thing the operator did was check the pressure indicator and noted that that

was the only one that was reading high. And further along the exercise, I noticed myself that since there was no other high-pressure indication that there was no protection action taken. You need two signals, two out of three or two out of four and so on. You didn't have that. You had that just one.

CONSULTANT WALLIS: Where was the pressure high?

MR. MIRANDA: The pressure wasn't high. The indication was high, the one indication was high.

MEMBER ABDEL-KHALIK: PRT.

MR. SHAFER: I'm sorry. This is Sam Shafer again. The control system for pressure comes off two separate channels that are only for control. The protection channels, which each one has its own pressure channels, is also looked at, but where the PORV automatically opens, there's an instrument failure of a control loop, not the protection channels.

MR. HALE: Steve Hale, FPL. Again, I don't want to leave the committee with a false impression also on boron dilution. We did a fairly extensive single-failure evaluation on that, and it would take more than just an operator error but several equipment failures along with that to actually

get to the point where you had a dilution event.

MR. MIRANDA: Right. As far as boron dilution is concerned, I do want to make a note here that analyzing the boron dilution only in Modes 1, 2, and 6 is very common. We've seen it on other plants. We've seen it referred to as Westinghouse methodology, especially with respect to the older plants. And Westinghouse, when answering my question, referred to Reg Guide 1.70 for support, and it wasn't there, not that I could find. And I asked them about it at the audit, and they didn't point to anything in Reg Guide 1.70 that indicated only those three modes were required.

MR. PARKS: At this point, we will segue into discussing the emergency core cooling system. Dr. Khalik mentioned some questions about the tech specs, and we'll talk about that and we'll review the ASTRUM implementation, the small-break LOCA results, and boric acid precipitation control.

The two Turkey Point nuclear units share four high-head safety injection pumps where a safety injection signal at either unit will start all four pumps, and those pumps will align for injection into the affected unit. Now, the ECCS evaluation credits two of those. And let me be clear about what I mean

with the tech specs. The limiting condition for operation is four pumps need to be operable, but while one unit is down it may have one of its ECCS pumps out or trains out for, you know, service for 30 days. So when I look at it from the reviewer, I'm looking for more than two units to be available at any given time, and that LCO structure that allows them to do their maintenance and testing and all that stuff assures that at least one of those units is going to be available so there's more than two. So that's how I approached it from my review perspective.

MEMBER SKILLMAN: Benjamin, when you did that review and you considered the four pumps, physical devices, did you determine that there is sufficient physical separation and sufficient independence of electrical supplies so that if your algorithm of I've got four, I've got one down for maintenance, I have three, I have one unit that's live, I haven't compromised the other three by some arcane interaction of circuit breaker alignment or fire barrier impairment or some other such thing?

MR. PARKS: I understand your question about train separation. And for an EPU review, the answer is, no, we don't review that. Our review is based on the presumption that that was addressed when

the plant was licensed, and so the EPU certainly affects some things that we go back and ask about, but the physical plant design we presume to be acceptable with respect to the train separation requirements that Turkey Point had to adhere to.

MR. SHAFER: If I may, this is Sam Shafer from Florida Power and Light. To answer the question, all four of the SI pumps do come off of independent power supplies, which are backed up with their respective diesel generators.

MEMBER SKILLMAN: Thank you. Thank you.

MR. PARKS: The upper tolerance limit for the large-break loss of coolant accident analysis was 2,063 degrees Fahrenheit, and these slides refer specifically to those analyses that were included in the licensing report. I have a couple of slides about thermal conductivity degradation at the tail end of my presentation, but I'm going to talk about what I reviewed right now, okay?

The best estimate was approximately 1650 degrees Fahrenheit, and those results were tightly clustered. There were a lot of 1650 --

CONSULTANT WALLIS: So you looked for the whole distribution?

MR. PARKS: I did.

CONSULTANT WALLIS: Okay. And it was a bell-shaped sort of thing, reasonable --

MR. PARKS: More or less, yes. There --

CONSULTANT WALLIS: It didn't have big humps at the end or anything like that?

MR. PARKS: I cannot say that with -- I have a picture, you know. During the closed session, I can show you how they were distributed.

CONSULTANT WALLIS: Then do that. That's fine.

MR. PARKS: So I'll be happy to share that at that time. I think that it is fair for me to say that the limiting PCT exceeded all others by about 65 degrees, so it was a little bit out there on the distribution. Typically, I like to make sure that the input parameters --

CONSULTANT WALLIS: How many runs was this based on?

MR. PARKS: I'm sorry?

CONSULTANT WALLIS: How many runs was this based on?

MR. PARKS: Is that a proprietary number? A hundred and twenty-four, I believe.

CONSULTANT WALLIS: I think it's 120-something -- 124? Yes, okay.

MR. PARKS: Is that right, 124?

MR. FREPOLI: Yes.

MR. PARKS: Okay. Their input parameter distributions are sampled from ranges that exceed the tech spec-permitted operating range, but in this case not by much. You just want to make sure that the distribution falls outside.

CONSULTANT WALLIS: As we discussed earlier, the biggest assumption for me is that the very large double-ended guillotine break probability is quite high.

MR. PARKS: Yes, the way samples these things, it does tend to do that.

CONSULTANT WALLIS: Yes, quite a bit.

MR. PARKS: For this model, they used a detailed downcomer model. It had nine vertical channels for this three-loop plant. And I looked at some additional results, and it looks like the ECCS bypass where you get a lot of liquid coming in and then going back out the break before it goes, I could see based on the results that I looked at that that appeared to have been conservatively modeled. And I know that there are some features of the ASTRUM model that sort of enhance that phenomenon. So I thought that was important to look at because the PCT is

occurring very early in the limiting transient. So that looked like that was okay in my assessment.

We questioned the decay heat modeling. I guess I couldn't get a very clear picture from reading the ASTRUM methodology how exactly this was done, and it turns out that the decay heat uncertainty is sampled. In the top five PCT cases, two were greater than nominal, and so the other three were less than nominal. I think that's okay here because the PCT is very early, so, you know, we've got some greater than nominal cases in the top five cases. So I think it's a reasonable analytic approach, and it is generically approved. And so the takeaway there is we are devoting more attention to this type of modeling in our realistic LOCA review efforts, and I guess there will be more to come on that. But for Turkey Point we didn't see any issues with it.

CHAIR SHACK: Just go back to that previous slide for a second. I mean, I wouldn't think that ASTRUM itself has anything to do with how you model the downcomer --

MR. PARKS: No, that's the WCOBRATRAC model.

CHAIR SHACK: Right. But, I mean, you presumably have to change it because the old response

surface thing included some conservatism that covered you that's now ASTRUM because it looks at less conservative input and somehow needs a more detailed model? I'm just puzzling -- I mean, I keep thinking of ASTRUM as simply a way of analyzing COBRATRAC output, but the COBRATRAC model itself has got to be right in order for ASTRUM to do anything correctly --

CONSULTANT WALLIS: It's never right.

CHAIR SHACK: Well, it's adequate.

MR. PARKS: What's the question? It's a more detailed downcomer model here.

CONSULTANT WALLIS: No, I think it's a good point. I mean, the ASTRUM takes care of uncertainties in the input --

MR. PARKS: Yes.

CONSULTANT WALLIS: -- like uncertainties in the decay heat.

MR. PARKS: Right.

CONSULTANT WALLIS: But it doesn't take care of uncertainties in how the code models the phenomenon, which really has 9 channels or 25 or whatever, in the downcomer. That's an uncertainty, which sort of is on top of the ASTRUM type uncertainty.

MR. FREPOLI: This is Cesare Frepoli from

Westinghouse. We'd like to comment on this. The ASTRUM, indeed, do the sampling of the uncertainties for several models and several input. There are some retained conservatisms in the WCOBRATRAC model features. One of these is the one listed here, which is the ECCS bypass. In the old model, when it was licensed originally back in 1996, we had a rather coarse downcomer modeling, which were for a three-loop. It was Bayesian three-node. Over time, we increased the noting for several application, not only for Turkey Point but other plants, because it was excessively conservative. This model has been validated against the same set of data we used in the original validation, showing that the bias is still retained but it's not as excessive as it was before.

CHAIR SHACK: Okay. So you introduced the extra channels to reduce conservatism?

MR. FREPOLI: Excuse me?

CHAIR SHACK: You introduced extra channels to reduce conservatism?

MR. FREPOLI: Yes, that's correct.

MR. PARKS: I guess FPL showed you the results for the small-break LOCA. They were about 1250 degrees Fahrenheit, and they were bounded by the large-break results with significant margin -- why do

I say that? The requirement in 50.46(a)(1)(I) is to ensure that you've analyzed the most severe, and so what we were looking at there was, you know, with that significant margin in the type, we would expect that there was pretty high assurance that the most severe is that from a large break.

Okay. Again, Dr. Ward could not be here to discuss boric acid precipitation. I will cover his slides and try to answer his questions or the questions you may have to the best of my ability, but, you know, those that are beyond my expertise I will have to defer and get back to you.

For Turkey Point, the large-break LOCA wound up being limiting with respect to boric acid precipitation. Here are some features of Turkey Point's ECCS design. Basically, okay, the hot leg break is what turns out to be limiting for precipitation because I guess what you're doing is you're piggybacking the low-head and the high-head pumps together and you're injecting into the core. So when you've got the two separated, you've got your flushing flow, and that's during the injection phase. And then once you empty the RWST and you go to re-circulation, you're supplying the high-head safety injection to the cold leg, and that's allowing your

boric acid to build up in the core. Then when you do that swap over and all your safety injection is going into the hot leg, that's when you get it to come down through and out around that way, and that's how you get your flushing flow. So the basic control strategy is to assure that you reinitiate your high-head injection before you get precipitation. So --

CONSULTANT WALLIS: The hot leg, right?

MR. PARKS: I'm sorry?

CONSULTANT WALLIS: The strategy is to switch the hot-leg injection, isn't it?

MR. PARKS: I think here it's a little bit different because -- again, this wasn't my review area, okay? So --

CONSULTANT WALLIS: But when you supply the cold leg with the hot leg break then you boil off in the core, so you switch to hot leg injection.

MR. PARKS: Right, yes. All safety injection is then switched to the hot leg for flushing flow at five and a half hours. So, yes, you --

CONSULTANT WALLIS: I think that's what it says here. It's not switching on HHSI, it's switching to the hot leg; isn't that right?

MR. HALE: Yes. This is Steve Hale, Florida Power and Light. During the injection and

initial phases of re-circulation, you're in cold leg injection. And then at a point of about five and a half or so hours out, you would switch to hot leg injection, and then you would sequence back and forth there from like 12 to 16 hours, and that's how you address the boric acid precipitation is through alternating cold leg and hot leg injection.

MR. PARKS: Okay. So for small breaks, the mitigation strategy gets you to re-establish your single-phase natural circulation. Then for the large breaks, we did some confirmatory studies to match what the licensee does. So some calculations are done. The mixing volume includes the core and half of the lower plenum. These calculations are basically I think a boiling pot to sort of figure out how quickly the boric acid concentration builds up and then compare it to the precipitation limit.

Both a Len's model and the licensee's use the 1971 plus 20 percent decay heat, and they consider it time dependent mixing volume. And what that means is the two-phase solution in the core is considered as a part of both. I believe the licensee uses a WCOBRATRAC model to figure out what that is, and I think that Len's uses a dripped flux model in his calculations.

MEMBER SKILLMAN: Before you go on, let me ask, please, Benjamin, how this analysis was handled for Point Beach, for Beaver Valley, for -- what is New Hampshire?

MR. PARKS: Seabrook.

MEMBER SKILLMAN: At Seabrook, please.

MR. PARKS: I believe that the analyses were handled in a similar fashion. I know that Westinghouse has developed its methods a little bit since, but the idea is these all follow a similar approach. And I think the big piece of it is how much mixing volume can you credit --

MEMBER SKILLMAN: Assume.

MR. PARKS: -- and I think that those are the key inputs.

CONSULTANT WALLIS: That is right. And this committee has always had some doubts about this half number because it seemed to be a little bit of guesswork.

MR. PARKS: Understood.

CONSULTANT WALLIS: And I think we've asked in the past for a better experiment or a better definition or a better understanding. I don't know what the status of that is.

MR. PARKS: I'm aware that there are some

tests being done in Germany in a test loop. I don't know what the latest results are from those tests.

CONSULTANT WALLIS: But there is some work on it?

MR. PARKS: There is some work that's being done. But in terms of our state of knowledge, the tests being done right now, we're still relying on the previous tests that we knew of before.

MR. HALE: This is Steve Hale of FPL. If you recall, we spent a lot of time talking about boric acid precipitation on the Point Beach. Point Beach had a slightly different configuration. They had upper head injection, which Turkey Point does not have. But if I can recall, the dialogue we had is there were a lot of conservatisms in the analysis itself. A couple I'd like to mention. One is there's no credit for containment pressure in terms of the solubility limits, you know. In other words, you assume the containment is at atmospheric. So that can have a significant effect on the precipitant, you know, where you would get precipitation. The second, and there's no credit for any kind of additives, you know, for pH control, which will also have the same effect and increase solubility of the boric acid.

So there's a number of conservatisms

already in the analysis, and you assume that all the boric acid stays in the core, that it boils off, that all the boric acid is concentrated in the core and none is carried over with some of the steam release. So there's a number of conservatisms, and I believe we reached the conclusion after a lot of discussion that that kind of offsets assumptions with regards to mixing volumes and things of that sort.

MEMBER SIEBER: But the half is, nonetheless, just sort of arbitrary?

MR. HALE: Yes. Well, Westinghouse would have to speak to that, but I think we discussed that at length in the Point Beach review.

MR. PARKS: This last bullet I will attempt to explain. I know that there is a concern that this vapor condensation can be a source of dilutant into the re-circulated coolant, which can then start to reduce the boric acid concentration. And without being 100-percent sure what exactly Len was going to say, I'll show in the next couple of plots what exactly this bullet point means in terms of the results of the analysis.

CONSULTANT WALLIS: But doesn't all condenser run back? Because then you wouldn't have any dilution, would you?

MR. PARKS: I'm sorry. Again --

CONSULTANT WALLIS: You just get a little bit of credit for condensation. It doesn't all condense and run back. Some of it, some of it.

MR. PARKS: Right. The bottom line is that the staff was --

CONSULTANT WALLIS: But they assume the 100-percent condensation.

MR. PARKS: I believe that was one of their analyses. I think this probably better captures it. The staff questioned that assumption, okay? I was getting a little bit ahead of myself. I apologize. The acceptance criteria here or, I'm sorry, the analytic result is they need to switch over at five and a half hours. And in all of the analyses, that's the original 8.3 with the 100-percent vapor condensation, the staff's 6.7-hour result, and the licensee's revised 7.1-hour result. They all validated that a five and a half-hour switch-over time was acceptable.

CONSULTANT WALLIS: Maybe I could ask Turkey Point what is this 100-percent condensation? If it boils off and all runs back, then there's no dilution, is there?

MR. HALE: Steve Hale again, Florida Power

and Light. Yes, this has been a kind of bone of contention between us and Len in a lot of our discussions. Certainly, if you want to concentrate boric acid, you assume it all stays in the core, so the fluid coming out --

CONSULTANT WALLIS: Well, the steam --

MR. HALE: -- it's steam without boric acid. Of course, the containment is at saturated conditions, and so, naturally, over time, you will continually dilute the sump. If you're making the assumption that all the boric acid --

CONSULTANT WALLIS: So that's where the dilution is is in the sump?

MR. HALE: Yes.

CONSULTANT WALLIS: It doesn't come back into the core.

MR. HALE: Right, right. But the bone of contention is how much of that is going to the sump and the timing of that, and that's where we get into the discussion -- right, right, right.

CONSULTANT WALLIS: No, I understand.

MR. HALE: Okay.

CONSULTANT WALLIS: That's good.

MR. PARKS: I think the general strategy is to make sure that you've got a lot of boric acid

coming because, certainly, you're going to entrain some of the boric acid and it's going to put out on upper bits of the core and out into the containment, but you don't really know how much. And so Len's calculations are trying to make sure that the boric acid continues to concentrate in the core while it's got a high concentration coming in, and that makes sure that it's conservative. I think that's his general idea.

CONSULTANT WALLIS: The thing is the operator has no indication whatsoever of what this concentration is. He's just told after a certain time you've got to do something.

MR. PARKS: That is correct. An important determination in Len's review was the fact that this swap-over operation involves an interruption of the safety injection flow. And so when that happens, there's a concern that the core could begin to saturate. And in order to preclude that, it's required for the operators to perform the switch in less than three minutes, so that's pretty quick.

I think Len asked to calculate how long there would be problems. I mean, just a boiling core post-LOCA isn't necessarily a big deal, but if it uncovers and you get another heat-up that is a

problem. So 27.8 minutes to core uncover and that, you know, provided it's complete within three minutes, they're not going to have that situation occur. He asked that we observe this in the simulator, as well, and we did and the operators completed this valve realignment within about a minute. There were a group of valve controls or pump controls, and basically they got the instruction from the mock-up TSC to do this. They checked their valve alignments and their pumps configurations, did it, and it was done. So it was a pretty prompt action.

MEMBER SKILLMAN: So just confirm that the reach rods are not involved in this changeover?

MR. PARKS: I'm sorry. The?

MEMBER SKILLMAN: Reach rods.

MR. HALE: Steve Hale, FPL, again. No, the reach rods are not involved with this action.

MEMBER SKILLMAN: I had to ask that question. I'm just making sure. Nuclear 101, ask twice, you know.

CONSULTANT WALLIS: When you switch over from cold leg to hot leg, you shut down the cold leg and then you open up the hot leg or is there a period when both are operating together?

MR. HALE: You actually, for run-out

concerns and also some flow, you actually have to shut off the pumps, close the cold leg valve --

CONSULTANT WALLIS: You have to shut them off?

MR. HALE: Yes, you actually have to turn the pumps off, or they'll run out, okay? So you have to shut the pumps off, close the cold leg valves, open the hot leg valves, restart the pump.

CONSULTANT WALLIS: I thought you could just open the hot leg valves and pump to both and then shut the cold leg up.

MR. HALE: If we could accommodate that by pump design, we would.

CONSULTANT WALLIS: Because then you're never stopping your ECC --

MR. HALE: Right. Understood.

CONSULTANT WALLIS: You probably could program that right and it would work. You turn two valves. You close one while you're opening the other and don't shut off any pumps.

MR. HALE: Your point is well-taken, but by the design we have we --

CONSULTANT WALLIS: You use your reach rods.

MEMBER SIEBER: The difficulty is if

something stops and you dead hit the pump and that's --

MR. HALE: Well, we did have a question regarding that, and the procedures call for restoring cold leg injection. If you have any point along that step that you're taking where you have a problem, you want to assure you always maintain flow to the core. That's why you have to be very careful when you step through the steps.

MEMBER SIEBER: Yes.

MR. PARKS: Okay. So at Turkey Point there's a need to switch the safety injection between the hot and the cold leg every 16 hours. I believe that this is to maintain adequate core cooling. I'm a little unfamiliar with this part. I apologize.

MR. HALE: The 16 hours is strictly related to boric acid precipitation.

MR. PARKS: Okay. So it's to maintain flush on its own?

MR. HALE: Right, right. In the early part of the event, you have, of course, higher decay heat and the potential to concentrate boric acid is much higher. As you go out in time, rather than stretching the different times in the operating procedures, we just established you've got to do the

initial transfer between five and a half and six and a half and then every 16 hours subsequent to that.

Now, as you go out into the event, you'll reach a point where you don't need both pumps any longer, you only need one pump. And I believe that's about 14 hours. So you'll actually, at the time that you transfer the second time back from hot leg to cold leg, you'll only need one pump at that point.

MR. PARKS: Results. These are the two licensee calculations. The upper curve here, we have an arrow, this is the vapor condensation model that Len had some issues with, and so he asked them to redo it with no condensation and that would keep the sump boron concentration or the inflows higher. I'm sorry. Squares are the lower, so that's vapor condensation. And then this higher result gets you to precipitation faster.

And then to compare the licensee's calculations to the staff's, you see this little hiccup here. Len's model does not permit any lower plenum mixing until, I believe, the density is sufficient to allow the boric acid solution that's in the core to fall down into the lower plenum. And so that's why you see this peak here, and then it goes up. And you can see that, aside from that feature,

which the licensee's model does not reflect, they are largely consistent. It turns out that that's, perhaps, not that significant in this calculation.

CONSULTANT WALLIS: Are they going to switch at about 20,000 seconds to hot leg? You got seconds instead of hours. That's something like 20,000, isn't it?

MR. PARKS: Yes.

CONSULTANT WALLIS: Which gives you a bit of a margin.

MR. PARKS: I think it was like six and a half hours was about the calculation.

CONSULTANT WALLIS: I was looking not at the hours margin but the concentration margin at that time.

MR. PARKS: I see.

CONSULTANT WALLIS: That seems to be a better margin measure because there are uncertainties. There's no uncertainty band on these calculations?

MR. PARKS: They are deterministic calculations perturbed with input parameters to make sure that they deliver a pessimistic result. The staff did some analyses to confirm the timing of boric acid precipitation and the staff's determination was that there is a good margin for the swap-over time

relative to the precipitation time.

The staff is a bit concerned with the control strategy here, which requires realigning between the hot and cold legs, you know, absent any action to fix this indefinitely. However, you know, two separate issues here. One, the operators can timely do the evolution, and that's okay. And, two, I believe that the licensee would, you know, at that point, be in a place where they're recovering, so their Technical Support Center would be informing their actions.

CONSULTANT WALLIS: I think that I suggest that when you rewrite this up, you should not say zero condensation. If there's no condensation, you'd simply be bulking up the containment. So what you mean is zero recycling of the condensate is what you really mean because it's very confusing to the reader if you see something at zero condensation. You're just pumping up the containment with steam.

MR. PARKS: I'll be happy to share that with my colleagues. Okay. Sort of moving into finishing up our review here. We did do three audits. There was a calculation audit of the boric acid precipitation analysis and mitigating strategy audit, and that was looking at the licensee's calculations

and comparing them to the staff's. We did simulator observation, actually, of three events. We did the inadvertent PORV, we looked at some main steam line break scenarios, and the boric acid safety injection swap-over. And, again, we did a calculation review in Pennsylvania to look at ASTRUM boron dilution, inadvertent PORV main steam line break, control rod ejection, and the feedwater line break. And those were the, that corresponds to the open items that were identified in our safety evaluation, and during our audit, we were able to bring those to closure. A couple of slides from now I'll summarize that, as well.

The calculations were performed acceptably. Just generally, this slide describes what type of material we were looking at during our audit. And then in the simulator, again, that operator actions were reasonably modeled in the safety analyses or that they made acceptable assumptions to sort of allow for the operator action in the safety analysis. They weren't being overly optimistic.

And so the open items that we resolved. For the boron dilution, the licensee provided additional justification for the charging flow assumptions. And so for that, we found that the boric

acid issues were resolved.

For the rod ejection accidents, we found the results to be a little bit anomalous based on what we would compare to other plants that we've reviewed. So the licensee showed us basically between beginning of cycle and end of cycle inputs the way that their analysis was done compared to their reference core design parameters. They had more margin at either BOC or EOC conditions, and so it caused the results to sort of flipflop. And it was mainly because there was more margin in one condition that they analyzed than another. And in both cases, there were substantial amounts of margin. It's not like they were eliminating or unacceptably eliminating their margins between their safety analysis and their core design.

For the inadvertent opening of pressurizer relief valve, we observed that the operator action in the simulator would mitigate a pressurizer filled before the pressurizer would. What we saw was nine seconds for a simple event, and what the analysis showed was five minutes to fill the pressurizer.

MR. MIRANDA: So the bottom line on item three is it's not the nine seconds that's important, it's the analytical result in terms of safety analysis. They had five minutes in which to mitigate

the event, and simulator demonstrated that they could do so within five minutes.

MEMBER ARMIJO: Well within five minutes. Before you leave this chart, I just want to ask a clarification question on your figures Slide 32. Why isn't precipitation limit a constant? Is it for a fixed lowest possible temperature of the fluid?

MR. PARKS: This being a large-break analysis, I believe that the assumption is that the containment is at atmospheric pressure. And so this is the precipitation limit for atmospheric pressure for unbuffered solution.

MR. MIRANDA: Yes. Len Ward said he was using atmospheric containment conditions.

MEMBER ARMIJO: Okay.

MR. HALE: Steve Hale again, Florida Power and Light. We actually looked at the impact of containment pressure on that solubility percentage, and at this time in the event the actual solubility would be up in the above, around 40 percent.

MEMBER ARMIJO: So you picked the lowest solubility --

MR. HALE: Yes. This analysis is extremely conservative from that standpoint. You know, it assumes you're at atmospheric and that sort

of thing.

MEMBER ARMIJO: Okay. Thank you.

MR. PARKS: For the large-break LOCA, we looked at some additional plots. I collected a lot of plots from the licensee to do my review to look at the downcomer modeling and how that was affecting the results in the limiting transients. Some additional plots were provided there so that I could understand where the liquid was going to see that it was going --

CONSULTANT WALLIS: Could I ask you again about boron precipitation? This solubility limit assumes everything is mixed up, whereas when you're boiling liquid which has some salt in it what happens is that when you make a bubble you essentially make steam and what's left behind is what's left behind. So the places where you actually are making the bubbles you tend to deposit whatever it is that's dissolved around the place where you make the bubbles, so there probably is some boron precipitation around the places where --

MEMBER ARMIJO: Right. Depositing on the fuel.

CONSULTANT WALLIS: Yes, which is not just governed by the overall solubility of the mix.

MEMBER ARMIJO: It stays there.

CONSULTANT WALLIS: You've got scale formation when you're a kettle around the place where boiling happens. It's not governed by the complete mixing of all the stuff in there. So I just wonder, someone must have -- this must be part of the history and the regulation, and I'm just wondering if you understand the difference between the overall solubility when it's all mixed up and what comes out when you actually boil on the surface and you make vapor on the surface and you've got encrusting around where you make the --

MEMBER ARMIJO: BWR all the time.

MR. PARKS: I have seen some testing that's benchmarked or, I'm sorry, benchtop and scale. So, you know, with that caveat, I'll just describe what I saw. For a buffered solution that had a bunch of different materials in it. It had some particulates and some solutions that were, I think it was aluminum oxyhydroxide designed basically to say get in there and make a sludge, which they thought would be worse, and this is in a three-by-three heated grid array. What happened was the particulates and the buffers tended to collect some of the boric acid down in the bottom, and then there wasn't anything that deposited on the heated elements. I think what

happened, you know, in terms of what you're describing with your flakes from the vapor generation, I think they were carried in the fluid up to the top. And so this thing is open to the shop, of course, where a reactor vessel is not. They tended to plate out up there.

CONSULTANT WALLIS: At the top?

MR. PARKS: Or entrain and just go out into the shop's atmosphere. And so that's what I saw. I mean, it's a different solution than just a pure boric acid --

CONSULTANT WALLIS: So the bubble goes along the wall, and it leaves behind a liquid film which boils away completely. So around the boiling centers, you always get that positive stuff. And this is taken into account? Or maybe it --

CHAIR SHACK: Some of it may be dissolved, though. I mean, it's kind of a complicated problem.

CONSULTANT WALLIS: It's dissolved later or something.

MEMBER ARMIJO: But as you get close to your solubility limit, very --

CHAIR SHACK: Yes, right. So that's kind of the argument is that all this happens, but until you really get the bulk solution up --

CONSULTANT WALLIS: You don't build up a really thick layer.

CHAIR SHACK: Yes. I mean, you'll lose some but not --

CONSULTANT WALLIS: It must be based on experiment.

MR. PARKS: I think the reflection in the model is the fact that all of that stuff stays in the solution. So maybe it may not play out on the field, but it is higher. So it's getting in bulk to the concentration limit faster.

CONSULTANT WALLIS: Well, if it plates out, then it changes the heat transfer from the fuel.

MR. PARKS: Let's see. Also, during the audit I saw some extended plots of downcomer liquid levels. I like to see the results go out for a large-break LOCA so I can see that the core level is stable and recovering. And in the plots that I got from Turkey Point, because the PCT is very early, I could see that. Some additional plots later showed that that continued for an extended period of time. They showed me plots for 2,000 seconds. And I got that clarification that I said on the ASTRUM decay heat modeling. And so based on the information that I gathered during that bit of the audit, I was able to

resolve the open items for the large-break LOCA analysis.

I should make you aware of an open item associated with the fuel storage. The licensee supplemented its application on November 9th. Some of the fuel storage tech specs were changed, and the licensee is providing additional information. So the staff is continuing its review of that. Fuel storage was done as a separate licensing action aside from and in parallel with the EPU request.

Results. The safety analysis results were acceptable for the licensing basis events. We asked for some analyses for events that were outside the design basis, and we believe that we got acceptable results for those. We're pulling forward out of this EPU review and from every other one that we do some lessons learned, and we think that there may be some revisions and adaptations warranted for RS-001 just to make sure that it continues to be a very useful tool.

The mass addition associated with the inadvertent PORV necessitates some generic communication, and we're continuing to work on that. And as I said, we are increasing our attention to the decay heat modeling and realistic emergency core cooling system evaluation. The staff in the Nuclear

Performance and Code Review Branch are doing that for several methods that are under review now.

We found the boric acid control analyses acceptable, but we do identify that the licensee needs to have a recovery strategy to ameliorate the need to cycle between hot and cold leg injection indefinitely. So the analyses show that 50.46(b)(4) and (b)(5) coolable geometry except long-term core cooling acceptance criteria are satisfied, but to get from there into recovery they do need to do something. Otherwise, they're just switching valves indefinitely.

So based on all of that, we found their proposal for the EPU adequately supported by the safety analysis.

CONSULTANT WALLIS: There is no GSI-191 this year?

MR. PARKS: I'm not sure how to answer that, Dr. Wallis.

MR. HALE: This is Steve Hale, Florida Power and Light. Yes, we've looked at GSI-191. The particular items, EPU has little or no impact on GSI-191 resolution. The areas where there is an effect have already been addressed and are included in our overall GSI-191 plan. So it's really being handled as an independent licensing action.

CONSULTANT WALLIS: I just thought it ought to be mentioned if you're talking about long-term cooling.

MR. HALE: Correct.

CHAIR SHACK: Well, I mean, the implication I got was that was what Florida Power and Light proposed. I wasn't sure what the staff disposed.

MR. PAIGE: I'll talk to the reviewer. This isn't the appropriate branch. And I can provide an answer.

MR. PARKS: At this point, there's a good pause. I'll cover fuel thermal conductivity degradation in my slides, or shall I do that? We recently learned that the effects of the fuel thermal conductivity degradation were quantified in a plant-specific ASTRUM analysis or, yes, in a plant-specific ASTRUM analysis. And so getting that knowledge and knowing that this information was already discussed in a previously released information notice and that we didn't believe that the results were going to be as significant as they turned out to be, we thought it was necessary to communicate with Turkey Point immediately since they had a licensing action under review. We didn't, you know, this knowledge needed to

be communicated and we needed to understand what they would do to address it. And so we made that notification to FPL last week, and, as they presented to you this morning, they're working to address that in the Turkey Point analyses not just for large-break LOCA but for the remaining safety analysis events, as well.

We are continuing to follow FPL's resolution. On the generic front, we released an information notice about the issue this morning. I believe I saw copies of that. Have you been supplied with it?

So Turkey Point is not the only affected plant. It happened to be the plant in here that is asking for an EPU. And so we just want to communicate to the committee that we are working with all affected plants on this right now, you know, with this generic communication vehicle and following up with our own inspectors and with our project managers here in NRR to make sure that this is done across the industry.

MEMBER ARMIJO: Is this across the fleet, BWRs, PWRs, or just some subset of PWRs?

MR. PARKS: This issue, the information that we got was specific to ASTRUM analyses. Westinghouse is one of two vendors of realistic, you

know, per the most recent revision of 50.46 ECCS evaluation models. This issue has a different effect and a different resolution for the other vendor's model and for the legacy CQD method that's offered by Westinghouse that affects it differently because it's, I believe it's more conservative and bounding of this type of, of this fuel thermal conductivity degradation phenomenon.

CHAIR SHACK: How does the third bullet follow?

MR. PARKS: I'm sorry?

CHAIR SHACK: How does the third bullet follow from all the information that you have?

MR. PARKS: My view of the issue is that, because everybody is operating and everybody needs to assess and do stuff, I don't think that this affects our conclusions with respect to the EPU request. We will certainly look at FPL's resolution, and we do know that they are taking steps to address it. But the reason that I say that or I guess my view when I'm making that point is so is everybody else. It's just that FPL has a license amendment under review that is it impacted by this issue.

MEMBER ABDEL-KHALIK: Not everybody else is going through an EPU that would raise calculated

peak temperatures.

CHAIR SHACK: And has a peak temperature of 264 degrees.

MR. PARKS: I think I --

CHAIR SHACK: Or 2,000. Sorry. Sorry.

MR. PARKS: I appreciate the point being made by the ACRS. I understand.

MEMBER ABDEL-KHALIK: No, the point that needs to be resolved is whether the applicant will complete the analysis in time and the staff will subsequently complete their review of the analysis provided by the applicant in time for ACRS to hold a full committee meeting in January, which is scheduled for January 19th.

MR. PAIGE: This is Jason. We understand your point. I'll work with the licensee in terms of working out a time frame in terms of when they plan on providing that analysis. I'll communicate that to Weidong. Until then, I guess you guys can make that decision if the ACRS full committee can continue on with that date.

MR. HALE: This is Steve Hale for FPL. Yes, our intent is to have these analyses and evaluation complete here very shortly, and we'll work with the staff and the ACRS to give you this

information as soon as possible. One of the things we did with, I know with the Point Beach ACRS subcommittee, we had a couple of items that required formal responses and we provided those in advance both to the staff and the ACRS, and we could do something similar here so that you have the information from us while the staff is performing their review.

MEMBER ABDEL-KHALIK: But, generally, the committee requires 30 days to evaluate materials submitted to it. And if the full committee is scheduled for January 19th, I just don't see how that requirement can be met.

CHAIR SHACK: We've bent that 30 days before for -- I mean, resolving an open issue is different than having --

MEMBER ABDEL-KHALIK: The full material.

CHAIR SHACK: -- the full material. I mean, you know, the question is how big we think this issue is and that may depend on how much margin you'll end up demonstrating at the end here when it's taken into account and how soon we get it. So at the moment -- well, we can discuss that later.

MR. BROADDUS: This is Doug Broaddus. I'm the branch chief who has the oversight for this licensing action, as well, in NRR. There are a lot of

uncertainties right now, and what I would ask of the committee is to give us some time to work with the licensee to try to come up with that schedule. If it looks like that we're not going to be able to provide information to you in a timely manner or if it looks like that it's going to be much more significant than that, we will certainly work with Weidong and let him know that and make sure that you're aware of that. I would just ask to keep our options open at this point and as we go forward and work towards that resolution.

CHAIR SHACK: We'll have some more committee discussion on that, I think. Time for a break. Back at 3:15.

(Whereupon, the foregoing matter went off the record at 2:58 p.m. and went back on the record at 3:25 p.m.)

MR. HALE: If I could -- this is Steve Hale, FPL -- we would like to close the action items that we had from earlier. I have two, and Carl will speak to two.

With regard to auxiliary feedwater flow degradation, they were overhauled approximately six to nine years ago, and we have about one to two-percent flow degradation in the pumps. After we refurbished the pumps, we expect to have approximately, you know,

to restore them to design, we'll have approximately seven percent flow margin between the pumps and what's actually assumed in the safety analysis.

MEMBER ABDEL-KHALIK: And that just involves a different --

MR. HALE: No. Basically, it's just clearances, you know, refurbishing seals, bearings, rotating elements, you know, that sort of thing.

MEMBER ABDEL-KHALIK: Okay.

MR. HALE: Okay. The second action item we had was with regards to the performance of the main steam safety valves, and we pop test these valves. We call it pop testing. We test them at full steam conditions. We confirm they have a band of plus or minus three percent, and we verify that the valves will lift within that plus or minus three percent tolerance, you know, within that pressure tolerance of their setpoint.

We've done 53 tests. We've had two cases where the valve was outside of its tolerance. We have not had any what I'll call failures where the valve stuck open or anything like that, but we have had two cases where the valve was outside of its specified plus or minus three percent tolerance. And of course this stuff is covered extensively under our IST

program and, dependent on failures, you have to increase your sampling, that sort of thing. But that's been the performance of our main steam safety valves. Oh, I'm sorry, in the last five years. Fifty-three tests in the last five years.

MEMBER ABDEL-KHALIK: And prior to that? I mean, you haven't changed the design, have you?

MR. HALE: No, no. I would say that's a good measure of what our performance has been with these valves. They've been very good. And, you know, we test them regularly, and if they fall outside the tolerance we have to increase our sampling to ensure it's all covered under our IST program. I'll say the last five years the performance has been excellent.

MR. O'FARRILL: I had two action items, one having to do, I think Dr. Khalik asked the question about axial offset anomaly and how we're managing the crud deposition on the fuel. There are a couple of things. I mentioned about the power distribution control, and that's one aspect of it. But the other aspect of it is chemistry. And so as we go to EPU, we're focusing more emphasis on the crud products and the nickel ferrites in the RCS, better monitoring programs and clean-up programs for any shutdowns that we may have. So that's going to be the

emphasis. It's similar to the approach that we take at Seabrook plant, which is a high-duty plant, as well.

And you wanted to have some results from what we have seen. I had mentioned the 0.3 pound mass total accumulation in the core. That's our design target as we go through from cycle to cycle to try to keep that, and that's the level for our 15 by 15 fuel whereas that's an indication of mild AOA. So we want to keep below that.

And the studies we have shown, we have shown on the order of less than 0.2. Of course, we looked at the initial cycles and then transition cycles.

MEMBER ABDEL-KHALIK: This is Westinghouse's code for calculating deposition --

MR. O'FARRILL: VIPRE/BOA, and it's actually an EPRI code that Westinghouse developed for EPRI in the industry so . . .

MEMBER ABDEL-KHALIK: Okay. 0.2 pounds is --

MR. O'FARRILL: 0.2 pound mass is what we've seen in our studies. And, again, that's a cumulative effect, so for the first cycle you have to worry about carryover crud on the fuel assemblies, so

the first cycle is going to be pretty benign, and then it will tend to increase as you get into your second and third cycle of EPU. The number I quoted you was the longer term --

MEMBER ABDEL-KHALIK: You have no plans for ultrasonic cleaning of the fuel or anything of that sort?

MR. O'FARRILL: We're looking at ultrasonic cleaning possibly but no sooner than the second cycle of EPU, once we start accumulating more boron. We currently do ultrasonic cleaning at Seabrook.

MEMBER ABDEL-KHALIK: Okay.

MR. O'FARRILL: The second question we were asked was the overall reactivity at cold shutdown conditions. And it is kind of core design-dependent, but I went and looked at, just to get a measure of pre and post at those times, and, basically, the difference is actually less than 100 ppm.

MEMBER ABDEL-KHALIK: One percent?

MR. O'FARRILL: Yes.

MEMBER ABDEL-KHALIK: Okay.

MR. HALE: I believe that's all the -- again, this is Steve Hale, FPL. I believe that's all the action items we had for us.

CHAIR SHACK: Okay. Back to you.

MR. HALE: All right, thank you.

MR. BASAVARAJU: Good afternoon. This is Chakrapani Basavaraju. I am presenting the structure integrity of the structure systems and components for the power uprate condition. Our review scope included the effect of the EPU on the structural integrity of pressure-retaining components and the supports, the act of pressurized supports, control rod drive mechanisms, steam generator and its supports, reactor pump and its supports, pressurizer and supports, and reactor vessel internals, water-mounted instrumentation guide tubing and supports, and seismic and dynamic qualification of mechanical and electrical equipment.

I'll just give the quick highlights of our review and the major points of our reviews. The EPU increases the power by 20 percent, which affected the steam and feedwater flow rates by approximately 15 percent and the hot leg and cold leg temperatures increase by 9 degrees and 2.6 degrees.

The piping systems that are mainly affected by the EPU, they include the main steam, condensate, feedwater, extraction steam, and heated drains, and these required some modifications to

piping and pipe supports and some equipment replacement and modifications to meet the EPU conditions. The structure evaluations of the systems and structures and components was based on the design-based methodology of the plant and the acceptance criteria, and the structural evaluations met the design basis code-allowable values.

The highlights I'm giving here for the reactor pressurizer supports. During our review, we identified to the licensee that the evaluation for EPU conditions should not be based on such environmental material test reports, and we requested the licensee to re-evaluate the reactor pressurizer supports based on the code-minimum strength values, and the licensee responded with a recalculation based on the code minimum value and demonstrated the structural integrity of the reactor pressurizer support components only for the condition. That's where the licensee tried to use CMTR values, and the re-evaluation showed that it met the code-minimum value.

Another item of interest, the licensee for EPU during power ascension plan, the licensee will monitor the steady state flow-induced vibrations are not impacting the plan piping supports or connected equipment. The methodology for monitoring the

vibrations is based on the generally accepted industry methodology, which is based on the ASME OM Part 3 code, and the licensee will collect data and CLTP and then monitor the data as they go up during EPU and compare the results collected with two acceptance criteria, Level 1 and Level 2. As described in the ASME code, Level 1 will go to the full 100-percent limit and Level 2 will go to only 80 percent of the limits, and then they have a process to follow if they exceed Level 1 or Level 2.

Another important item is to maintain the current design limits at EPU conditions. The licensee has to implement a modification which required the addition of a supplemental spent fuel pool heat exchanger and associated piping and supports. However, the licensee has not completed its design and analysis, so the staff identified and imposed a license condition, which is in the next slide, please.

The license condition we proposed is to, before the licensee can use the additional cooling capacity from the supplemental heat spent fuel pool heat exchanger, the licensee shall complete and confirm to the NRC staff that the design and structural integrity evaluations associated with the supplemental heat exchanger and the associated piping

and supports are completed and the results demonstrate compliance with the design basis FSAR criteria and code requirements.

MEMBER ABDEL-KHALIK: Now, the wording of this first bullet implies that they can go ahead and implement the EPU prior to actually doing this.

MR. BASAVARAJU: Yes. This is a kind of special situation that, even though it's required for EPU, they would not need this until they shut down the plant and move the fuel into the spent fuel pool. So that's why we put the condition that they can go ahead with the EPU; however, before they start using or unloading the fuel, then they should be able to complete.

MEMBER ABDEL-KHALIK: Does this make sense to you? That you would allow them to go and start the plan, run a cycle at EPU conditions, without knowing whether or not the spent fuel pool cooling, when it comes to de-fueling the core, will be adequate or if, for some reason, they have to offload the core during the cycle?

MR. BASAVARAJU: Yes. Then, of course, they should have completed this analysis and they should have demonstrated --

MEMBER ABDEL-KHALIK: But that's not what

these words say.

MR. BASAVARAJU: The next second bullet after this says that the licensee should provide the evaluation summary to the staff before they can use the -- maybe the licensee can add something to this.

MR. HALE: This is Steve Hale, Florida Power and Light. We have designed the system.

MEMBER ABDEL-KHALIK: But you agree that this just doesn't make sense the way it's worded? Because it would allow you to go and run at EPU conditions before this is actually confirmed as to whether or not it's adequate?

MR. HALE: I can't speak to the NRC's licensing condition, but what I can say is that our intent is to complete this design and implement it during the refueling outage for EPU. The basic piece that's not available right now is the pipe stress analysis, you know, the details of the pipe stress analysis. The design of the heat exchanger, the design of the system, the flow rate, that sort of thing has been completed. The staff asked for the detailed stress analyses, which are still ongoing. But I --

MEMBER ABDEL-KHALIK: So it wouldn't have much of an impact on you if the wording of this has

changed to require that this analysis be completed before the EPU is implemented.

MR. HALE: I would say, based on our current plans, that that would not impose too much of a difficult --

MEMBER ABDEL-KHALIK: And that would make this sort of more sensible --

MR. HALE: If I could speak, I think one of the concerns is that we might put it into service prior to that.

CONSULTANT WALLIS: There's nothing here that says it has to be put into service. I think it has to be put into service and the analysis presented.

MR. ZIELONKA: If I could add -- this is Andy Zielonka. I'm the engineering manager. If I could just clear this up. The wording can be changed, but, basically, the design is done, it's out. We're in final preparations to install them out. This outage we're going to be making the connections into the system before we shut down, before we offload the current load. And then a heat exchanger and all of that work, once they are done, will be installed, you know, later on. So the design is done. This is just a follow up as it came during the earlier review of the submittals of the LAR. At that time, it was not

done. This is just a follow-up action to submit the final designs and all of that for the NRC review.

MEMBER ABDEL-KHALIK: This is perfectly fine. All I'm saying is that these words don't make sense.

MR. ZIELONKA: If I can, I can agree with you. But just because the modification isn't yet implemented, we are not going to be starting up under EPU conditions without this heat exchanger mod being implemented.

MEMBER ABDEL-KHALIK: Right. But that's not what the license condition implies.

CHAIR SHACK: Or at least that's not what the view graph says.

MEMBER ABDEL-KHALIK: Right.

MR. BASAVARAJU: I apologize, and I will correct this license condition per ACRS' recommendation that the design should be completed --

CHAIR SHACK: Well, the design and modification should be completed --

MR. BASAVARAJU: -- completed prior to the implementation of the EPU.

MEMBER ABDEL-KHALIK: Right.

MR. HALE: I believe we have, you know, some commitments in there. I think we can just make

the wording the same, Jason, that will complete these prior to start-up from the, you know, prior to achieving EPU conditions.

MR. BASAVARAJU: That was a very good catch, and I apologize for the wording. Next slide, please. A quick overview of the high energy line break methodology. Turkey Point is not changing their high energy line break methodology. It's based on AEC's Giambusso Letter of 1972, and the licensee is continuing the same methodology, which was use it prior to EPU as the last part of the license renewal, and they're continuing the same methodology for EPU. And the acceptance criteria based on the GDC design criteria number 40.

Next slide, please. The high energy lines postulation is based on 200 degrees Fahrenheit temperature and pressure exceeding 275 psi. Over six systems made this category: main steam, feedwater, aux feedwater, steam generator blowdown, chemical and volume control, and RHR. The existing design of these structure systems and components not impacted by any plant modifications. They remain acceptable and feels that the prior modifications, those will be installed prior to the implementation of EPU to address the ruptured locations and any associated dynamic effects.

MEMBER SKILLMAN: Would you please give some examples of the SSCs that are affected by the plant mods?

MR. BASAVARAJU: The next slide. I am getting there. There is six feedwater heater and the nozzle modification in support of EPU that was affected. The licensee postulated ten breaks at the feedwater heater nozzle, and the nozzle size for EPU they had to change from 18-inch to 24 inches. So that affected the zone of influence for the jets coming from that break. And so to address this, the licensee had to make some modification --

CONSULTANT WALLIS: The zone of influence for what?

MR. BASAVARAJU: To accept these structure systems --

CONSULTANT WALLIS: There's a zone of influence based on pressure or something. And if something is more fragile, the zone of influence is bigger. If people are there, it's different. So this must be based on zone of influence for damage to some specific thing.

MR. BASAVARAJU: The safety-related components --

CONSULTANT WALLIS: They all have the same

fragility, or there's one that's most fragile and this is the zone of influence for the most fragile component?

MR. BAIN: Excuse me. This is Bob Bain from Shaw Stone & Webster. Pipe rupture postulations and zone of influence is just based on piping geometry. That's why you see the dimension change from 13 feet to 18 feet because the pipe diameter changed in size from 18 inches to 24 inches. It's purely geometric.

CONSULTANT WALLIS: But that doesn't make sense.

MR. BAIN: Well, but it's just describing the zone of influence. Within that zone, there are targets. At Turkey Point, the six-point heaters are outside, as we said earlier. They're on the, you know, the upper deck. The tresses building, the main steam building that became the target here, it's basically a graded building. It's not a concrete building. So the six-point heaters are about ten feet west of this graded building, and if you postulate a break based on this line size, based on a dispersed flow, so if you break the pipe, you exit, in this case, the high-energy fluid, it dies out over a certain distance. But it's only geometric, so within

that zone of influence --

CONSULTANT WALLIS: It doesn't die out --

MR. BAIN: Sorry.

CONSULTANT WALLIS: -- at certain feet. It just becomes weaker.

MR. BAIN: Yes, exactly.

CONSULTANT WALLIS: So this must be based on how robust these pressure transmitters are.

MR. BAIN: Exactly again.

CONSULTANT WALLIS: And there's been some kind of a test or evaluation --

MR. BAIN: It is.

CONSULTANT WALLIS: -- of what the pressure is necessary to damage them, and that must be the basis of the zone of influence.

MR. BAIN: There's other targets within this zone of influence. But as you said, they're more robust. The sensitive items that became a critical item, which is why they're putting in a shield, are fragile because they're rather not robust. But the actual dimension, this 18 feet, is based purely on geometry.

CONSULTANT WALLIS: But it can't be.

MR. BAIN: So there's other things within 18 feet, but they may not be affected because they're

more robust.

CONSULTANT WALLIS: I mean, yes, but if a person is standing at 20 feet, this person would be in the tank.

MR. BAIN: Would be in the --

CONSULTANT WALLIS: Not just for geometry.

MR. BAIN: Yes, these shields are not OSHA or personnel protection. These heat exchangers, these feedwater heaters are on the operating deck.

CONSULTANT WALLIS: You see what I mean. It can't be a zone of influence independent of what the target is. You must specify the target in order to have a zone of influence.

MR. BAIN: No, the zone of influence is just a zone. It's just an area. But within that area -- semantics here.

CONSULTANT WALLIS: Well, let's see. What's the zone of inference for a hand grenade?

MR. BAIN: Well, yes, right --

CONSULTANT WALLIS: It depends on what's there.

MR. BAIN: That's not a bad analogy, basically. Yes. If you had a head grenade, like you say, it has a zone of influence. And if you had pieces of paper within the dispersion of the hand

grenade material, it would be ripped. But if you had a four-foot block of steel, you'd put a few scratches in it basically, but the distance those metal pieces from the hand grenade went, that wouldn't change. That has, again, nothing to do with what the targets are.

CONSULTANT WALLIS: But how fast they're going when they get there would change. Anyway, I think you understand what I'm saying. I'm just surprised to see a zone of influence. It really has to say zone of influence for some particular target. It really has to say that. Is there some kind of staff position on that? A piece of paper is different from a safety-related pressure transmitter if it's a target.

CHAIR SHACK: Right. We have a zone of influence in GSI-191. You can have the same jet. The zone of influence is bigger if you've got Nukon insulation than if you had steel-wrapped insulation. I mean, Professor Wallis is absolutely right. I mean, it makes no sense to talk about a zone of influence. You can talk about a pipe width. That's more a geometric thing where you're either within the range of the pipe width or not, but a jet? That really depends on the fragility of the components you're

looking at.

CONSULTANT WALLIS: Well, think about the a jet engine on the tarmac. I mean, if you've got a piece of paper lying on it, it's going to be blown away if it's hundreds of feet away from this thing. If there's someone standing there, he'll just stand closer. And if it's a truck, it can get closer. It depends on what the target is. Anyway, that's a point.

MR. BASAVARAJU: That point is well taken, Dr. Wallis. The licensee performed a walkdown for this area where this feedwater break is and identified three related pressure transmitters in Unit 3 and five transmitters in Unit 4. They'd be influenced by this break; and, therefore, they had to install jet shields to divert this from these safety-related components to protect them.

CONSULTANT WALLIS: So the licensee performed the walkdown?

MR. BASAVARAJU: Yes, sir.

CONSULTANT WALLIS: Was there anything more fragile maybe at 20 feet?

MR. ZIELONKA: This is Andy Zielonka again. What this is is the feedwater heater, and, like Bob mentioned, it's a discharge nozzle off the

feedwater heater that went from 18 to 24 inches. What's to the right of that is a walkway, and what's to the right of that is a security barrier type grading. And then two or three feet away from that is the pressure transmitters that are mounted on the wall. So there is nothing between. There's the feedwater heater, there is a walkway, there is a vital area barrier which is just grading and there's three or four feet of that. These transmitters are mounted on the wall.

We looked at other options to mitigate that, such as protecting the actual transmitters which would have taken up space since it's a walkway for operations to do. So what we decided is just to put a deflector that would deflect the steam and the water downwards towards the floor in case there was a break. There was nothing else in between there and those transmitters.

CONSULTANT WALLIS: There's nothing else on the wall but these safety-related pressure transmitters?

MR. ZIELONKA: Mostly, right. Those are the only ones that are safety related --

CONSULTANT WALLIS: Well, I'd be concerned if there was sort of 20 things on the wall, and you

said, well, these ones are only going to be affected because they're within 18 feet but there are things within 19 and 20 feet --

MR. ZIELONKA: No, there's not.

CONSULTANT WALLIS: There's nothing like that?

MR. ZIELONKA: No, sir.

CONSULTANT WALLIS: Okay.

CHAIR SHACK: Well, how did you settle on the 18 feet?

MR. ZIELONKA: I think, as Bob mentioned, that's all the criteria that comes out based on the size of the nozzle. That's how you, a certain amount of diameters away from the break is when you --

CONSULTANT WALLIS: So reduce down to 20 feet from this nozzle?

MR. ZIELONKA: No.

CONSULTANT WALLIS: Well, so the zoning influence for you would be much bigger.

MR. ZIELONKA: Right. Well, the criteria is for protection of safety-related --

CONSULTANT WALLIS: This is an NRC criteria?

MR. ZIELONKA: Like Bob mentioned, the --

MR. BAIN: This methodology, it's fluid

mechanics. It's fluid mechanics. And, again, you're not protecting people. I mean, this pipe rupture review is for safety-related --

CONSULTANT WALLIS: But it must be based on impact pressure or something.

MR. ZIELONKA: And temperature also.

CONSULTANT WALLIS: And it's an NRC criteria?

MR. BASAVARAJU: It comes from the ANS, American Nuclear Society --

CHAIR SHACK: The ANS jet model.

CONSULTANT WALLIS: But it doesn't die at 18 feet.

CHAIR SHACK: Well, that's what I'm trying to figure out.

CONSULTANT WALLIS: You've got a pipe over there where you're sitting and then there's something over here. That's with 18 feet or something. That jet isn't stopping at 18 feet.

CHAIR SHACK: With a 24-inch nozzle?

CONSULTANT WALLIS: With a 24-inch nozzle? At these pressures? No way.

MR. BAIN: The original criteria was actually attached to the Giambusso Letters and O'Leary Letters from 1972 and '73. These are industry

standards. You know, this is not a Turkey Point plant-specific methodology. This is industry methodologies that have basically evolved since the 1972 and '73 time frame.

CONSULTANT WALLIS: But this --

MR. BAIN: They were later incorporated in the SRP, Standard Review Plan, Section 3.6.1 and 3.6.2.

MEMBER ARMIJO: I think the question that I'm hearing is if this equipment was located beyond your 18-foot zone of influence, would you still put up a deflector and a shield and everything if it was at 19 feet or 20 feet? My guess is you would put up your deflector even if it was beyond that 18-foot thing.

MR. ZIELONKA: Well, if it meets the criteria, it meets the criteria. If it's outside of that, that's what the specific walkdowns are for, measurements in order to satisfy the criteria. And, you know, as you can imagine, this is very conservative. Eighteen feet away from a line break, you know, it all dies away fairly quickly. So that is fairly conservative.

MEMBER ARMIJO: I'll defer to guys that know more about this than I do. I would think that I'd want to be further than that, my equipment anyway.

MR. ZIELONKA: Right. But you've got to recognize that the equipment that we're talking about here does have a certain qualification to withstand certain pressures and temperatures. It's not like --

MR. BAIN: The zone of influence, for example, a main steam line is about 30 feet for example. The main steam is higher pressure, well, higher temperature than these feedwater heater lines. The main steam is about 33 feet. And also, as Andy said, there's really nothing else in this tresses building that's related to safe shutdown of the plant. It's pretty robust. We have large pipes, large supports, and pipe-whip restraints.

MR. BASAVARAJU: I will look up for the guidance in our SRP and I will supply it to the ACRS. So based on our review of the licensee's evaluations, the staff concluded that there is reasonable assurance that the plant's SSCs are important to safety, are structurally adequate to perform the design functions under EPU conditions, and I will modify the license conditions about the spent fuel pool heat exchanger modifications, as suggested. That concludes my presentation. Questions, please?

MEMBER ARMIJO: I had a question on material you didn't cover, and that's related to cast-

offs, namely stainless steel components. That was under your scope of review. I think this section covers a whole bunch of stuff, right?

MR. BASAVARAJU: Yes.

MEMBER ARMIJO: But you couldn't present it. And in the safety evaluation, you talk about the impact of EPU, increase of the temperature in the hot leg wouldn't significantly affect the thermal aging of the stainless steels. Was that part of your review?

MR. BASAVARAJU: No, that's --

MEMBER ARMIJO: Will that be presented elsewhere?

MR. BASAVARAJU: Which section is that? That's not part of my review.

MEMBER ARMIJO: Was not part of your review.

MR. BASAVARAJU: No.

MEMBER ARMIJO: Maybe I should defer the question to a later part of this presentation, but we're running out of slides.

MR. HALE: What section is that?

MEMBER ARMIJO: Oh, gosh, I don't know. It's right here. I'm looking at it. Oh, I don't have a section number.

CHAIR SHACK: When I looked at that, Sam,

I went back and I looked at the license renewal and what they'd assumed is that it had reached, essentially, its saturated condition. So it doesn't make any -- it's as real as it's going to get.

MEMBER ARMIJO: Well, that was the question I was going to get at is, you know, it gets hotter. And what I wanted to know is, you know, since it's operating at higher temperatures and its thermal aging is an exponential function of temperature and the staff comment was simply that their judgment or their belief was there's no problem, I wanted to know if anything quantitative, has there been any calculations done to demonstrate that this material won't be embrittled at a faster rate than --

CHAIR SHACK: It undoubtedly will be embrittled at a faster rate but --

MEMBER ARMIJO: How much?

CHAIR SHACK: -- what they used was the worst-case value, which is what it's based on in the license renewal. You just assume that whatever your ferrite was it was fully embrittled. Certainly, the EPU will get there faster, but it won't get any more brittle.

MEMBER ARMIJO: Oh, okay. So they --

CHAIR SHACK: So they --

MEMBER ARMIJO: -- already had a limit?

CHAIR SHACK: They already had a limit.

MEMBER ARMIJO: Okay, okay.

CHAIR SHACK: And so it was sort of done back in the license renewal days, and almost everybody has done that. Very few people try to argue their way through the kinetics of the embrittlement.

MEMBER ARMIJO: Okay.

CHAIR SHACK: It's too difficult.

MEMBER ARMIJO: Well, I'm glad you're here, Bill, because it wasn't in the SE. Okay, thank you.

MR. PAIGE: So your question was --

MEMBER ARMIJO: No, I'm satisfied.

MR. PAIGE: That concludes mechanical and civil. For this next presentation, it's human factors, and the reviewer is actually offsite and will be doing the presentation via phone. Weidong is going to check if he's on the phone.

MR. LAPINSKY: I am on the phone, Jason. Can you hear me?

MR. PAIGE: We can hear you.

MR. LAPINSKY: Okay.

MR. PAIGE: His name is George Lapinsky.

MR. LAPINSKY: Okay. Are you ready for

me? I hear somebody shuffling papers.

MEMBER ABDEL-KHALIK: Can you hear him, Mr. Transcriber? Just hold on for a minute.

MR. LAPINSKY: Okay.

MEMBER ABDEL-KHALIK: Okay. Now say something. We need a test.

MR. LAPINSKY: I'm George Lapinsky. I'm a human factor specialist with the Health Physics and Human --

MEMBER ABDEL-KHALIK: Okay.

MR. LAPINSKY: How does that sound?

MEMBER ABDEL-KHALIK: Sounds good.

MR. LAPINSKY: Okay. Like everybody else, I used the Review Standard 001, and I reviewed changes to operator actions and their affects on procedures, human system interfaces, and training. Next slide.

The first thing I'll go through is training. The licensee identified a lot of editorial or setpoint changes to the procedures, but the only changes they identified as significant were those that you see here. All the changes, including these and minor changes, were reviewed for accident scenario impact and critical timing impact and found they have no significant impact on time critical steps or on operator actions in the emergency procedures.

MEMBER ABDEL-KHALIK: Excuse me. There's a change in the steam generator LOLA level setpoint. That doesn't enter in any other EOP whatsoever?

MR. LAPINSKY: Well, changes to setpoints would be considered minor change rather than the significant change in my area. You know, it might mean something to somebody in reactor systems, but in my area a change to a setpoint is on the order of an editorial change.

MEMBER ABDEL-KHALIK: So how do we make sure that all of those changes are correctly implemented in the procedures?

MR. LAPINSKY: Well, they've made statements that they have gone through these. They have an emergency and normal operating procedures verification and validation procedure. And anything that's in the emergency operating procedures that changes goes through this verification and validation process, which includes simulation, if possible; walkdowns; and the last. So, basically, they do a verification validation on those things. So we take them at their word, you know. We don't go through every change in the procedures. We don't review the procedures themselves.

MEMBER ABDEL-KHALIK: But you'd review the

program by which they assure that these changes are correctly implemented, wouldn't you?

MR. LAPINSKY: Well, they described the program. And like I said, they do have a procedure. We had the title of the procedure if we should want to take a look at it.

MR. HALE: Dr. Khalik, this is Steve Hale, FPL. The specific setpoint you mentioned is an RPS trip setpoint, which is controlled by the tech specs and has specific uncertainty analyses and everything involved with it. And that was reviewed by the --

MEMBER ABDEL-KHALIK: And we're only using that as an example --

MR. HALE: I understand, right. So those setpoints covered by the tech specs certainly get scrutiny by the staff and a detailed review by the I&C folks. In fact, any new ones that we're changing are in line with TSTF-493, Rev 4. Other setpoints in the EOP bases are certainly controlled by a program. They have uncertainty analyses associated with them and calculations to base them. Those are implemented through modifications. So in terms of specific setpoints in the EOPs, we do identify them in the LAR, and there is a program for control of those. And, you know, they have specific uncertainty analyses for

every setpoint in the EOP.

MEMBER ABDEL-KHALIK: There are statements, for example, in the EOP, verify adequate aux feedwater flow. And now under EPU conditions, adequate aux feedwater flow has changed. So how is all that correctly implemented? How do we assure that all --

MR. HALE: Changes of those type are controlled by a modification program, you know, that address impacts to safety analysis, as well as, you know, your DBDs and things of that sort, and through a modification process that we do under 50.59. Now, if they're specifically related to tech specs and that sort of thing, then it would be reviewed by the staff as part of this application. We have some of those. But a lot of the setpoint changes, while we do identify some of those setpoint changes in the LAR, they are controlled by our modification process and they would be implemented as part of that modification for the EPU. And they would cover all the downstream effects, you know. Like procedure changes, the analysis changes, anything required to drawings, those kind of things would be all captured in the mod process.

MEMBER ABDEL-KHALIK: Okay, thank you.

Please proceed.

MR. LAPINSKY: Okay. We should be on the slide now that says "procedures continued." Are we there?

MR. PAIGE: Yes, we are.

MR. LAPINSKY: Okay. Since there were only these three significant changes to the procedure, we went into those a little bit more and found that the analysis that was done on how long a delay the HHSI flow can be interrupted was changed from ten minutes down to three minutes. So I asked them questions about that, and the answers were that the simulator validation of the one-pump configuration has been done and they demonstrated that that action takes less than two minutes. Adding the new high-head pump will add ten seconds to that two minutes or less, and so they should have sufficient time to get it done in three minutes. But this assumption is going to be confirmed when the procedure changes are verified and validated, and they'll do that prior to the EPU startup in accordance with the procedure that I had mentioned earlier. Next slide.

CONSULTANT WALLIS: Does this time include the time to recognize that they have to do it, or it's just the time from when they decide to do it until

it's completed? Does it include some sort of a time for decision-making or recognition of an action needed or something like that?

MR. LAPINSKY: Well, I can tell you from our point of view it starts when the operator has an alarm or some recognizable point that he can start.

MR. HALE: This is Steve Hale, Florida Power and Light. This specific time is the time we spoke of for boric acid precipitation.

CONSULTANT WALLIS: This is to do the actual action, isn't it?

MR. HALE: Right, right.

CONSULTANT WALLIS: It's not to recognize it's needed?

MR. HALE: Right. The procedure will have a specific time that says it needs to be accomplished within this --

CONSULTANT WALLIS: That's a long time to make the decision now we're going to do it. Once they decide to do it it takes two minutes?

MR. HALE: Right.

CONSULTANT WALLIS: I thought that was it.

MR. HALE: Right. And, again, the staff also described -- that was one of the observations they actually observed on the simulator.

CONSULTANT WALLIS: Because the usual problems with operator actions are when they realize that they have to do it, that sort of delay. But it isn't in this case.

MR. HALE: Right. This is at a specified time frame in the post-LOCA long-term cooling.

MEMBER ABDEL-KHALIK: They would be like in E1 before they get to this transfer to this particular --

MR. HALE: That is true.

MEMBER ABDEL-KHALIK: -- ES1.3 or ES1.4.

MR. HALE: You're correct.

MR. LAPINSKY: Okay. Go on to human system interface changes. They had extensive changes, but mostly they were minor and had to do with ranges and scaling, replacement of indicator faceplates and banding and color-coding, that kind of thing. There was a significant change to the EHC turbine controls upgrade. That changed to an access through a password-controlled touchscreen. And this, like the other mods, will be done in accordance with the human factors program that's based on NUREG 0700 and, additionally, if there are any interfaces with EOP program, they'll do the verification and validation.

Next slide. Training. Proposed training

is going to focus on the tech spec changes, procedure changes, and plant modifications, and it's going to be done in the cycle prior to the EPU outage. And the simulator will be upgraded on the same schedule so that the training can be done before the plant operates under upgraded conditions. As a result, we're going to have a situation where, prior to any operation under upgraded conditions, the simulator will be used and the operators will be able to demonstrate that they have an understanding of the integrated response of the upgraded plant.

Next slide. The conclusion we drew was that Florida Power and Light has appropriately accounted for the effects of the EPU and they've taken appropriate action as to ensure that operator performance is not adversely affected by the proposed EPU. That's it for my presentation.

CHAIR SHACK: Thank you. Any further questions for Mr. Lapinsky? Hearing none, we can close that portion of the meeting. Any comments from the public? Any comments from public on the phone line? Okay.

I guess one of the issues is, essentially, how we want to handle proceeding since we're, unlike most of these things, we don't have all of the

information that we need at the moment. Discussing with my colleagues, we sort of came up with a date of around January 10th that we'd like to have all the information from the staff and the licensee. And, obviously, we'd prefer to have the information from the licensee sooner than that, but that's roughly the timescale that we're thinking about. I don't know whether the staff can just sort of think that over. It's not something, perhaps, we can settle today. You can discuss that with Weidong. But if you can't make that kind of a schedule, let us know because the feeling is that we're going to have to rearrange the schedule for our full committee meeting, and we want to give those people some time. We can't tell them on Wednesday that their presentation has suddenly been changed from Friday to Thursday.

MR. ULSES: Right. I think that's probably the best way to proceed at this point. I think it's a fair way of putting it, and, as we discussed, we'll talk with Weidong as soon as we have an opportunity to talk with the licensee and understand what their plans are. It's going to boil down to the scope of what it is we need to look at, and at this point we don't know the answer to that. But I think that's, I think it's probably the best way

to proceed at this point. And by the way, I'm actually Anthony Ulses, the branch chief of Reactor Systems Branch, for the transcript.

MEMBER ABDEL-KHALIK: I guess we have to issue an FRN if we're going to change the meeting agenda and sort of set a minimum time ahead of the meeting.

CHAIR SHACK: Yes. So our January 10th is our time. The staff may decide that they need even more time if we need to get the FRN out even earlier.

MR. ULSES: I was having a side conversation. I apologize. I think the time limits objective for an FRN is actually ten days.

MEMBER ABDEL-KHALIK: Ten days.

MR. ULSES: So we're maybe probably looking more like the 9th of January --

MEMBER ABDEL-KHALIK: Correct. Which is a Friday.

MR. ULSES: -- to meet the time limits objectives.

MEMBER ABDEL-KHALIK: The 9th is a Monday.

CHAIR SHACK: Okay. That's how we picked the 10th.

MR. ULSES: So perhaps we should settle for the 9th. That would be the appropriate date in

order to meet the objective to have the FRN notification.

MEMBER ABDEL-KHALIK: Okay.

CHAIR SHACK: Are there any further questions for the licensee or the staff?

MEMBER SKILLMAN: Yes. I would like to repeat a concern that I have on the overheating event. An overheating event is a loss of offsite power, possible loss of offsite power, that drives your plant, that drives the reactor coolant system to a very high pressure and that will also drive the secondary side the same way. And the margin is so slim to the, reactor coolant system pressure margin is so slim to the 2750, I just want to communicate that that seems to me to be, of all of the things we've spoken about today, the one area where the margin is most slim. There have been these two events, one in 2001 and one in 2005 and again in 2008, where there was a grid interruption or a partial or some part of a loss of offsite power. That is really a loss of heat sink for a pressurized water reactor, and that will drive both primary and secondary pressures.

And so I find myself concerned about the thinness of the margin for the 2750 psig for the reactor coolant system. That concern is secondary to

resolution of the pellet thermal conductivity that we'll get information on on the 9th of January, or before then hopefully. But I find this one area, loss of load and RCS pressure, to be one that I think we need to take a very close look at because we're not talking about the difference between the operating pressure and reactor coolant system pressure. We're talking about the difference between the ACME limit for reactor coolant system pressure. And in my view, that's another ball game. This is pushing the 2750 psig limit.

MEMBER ABDEL-KHALIK: This analysis assumes a certain number of safety relief valves on the secondary side to be open, and I assume that that number is much less than the actual number of valves they can potentially open; is that correct? What is the number of safety valves on the secondary side that are assumed to be open in this analysis?

MS. ABBOTT: This is Liz Abbott from FPL. Just to I guess comment on the analysis methodology as a whole, we are looking at an accident analysis, so it does include conservatisms in the modeling, in the input assumptions, and things like instrument uncertainties are factored in, equipment performance that mitigates the event, you know, is degraded type

of a situation. When we look at these type of results, everything is skewed in a conservative direction.

And we know when we look at an event such as a reactor trip and we compare it to the model results, similar model results for reactor trip, we know that there's a difference between what we see in accident analyses space versus what's actually experienced in the plant. So there's an inherent margin that's there. The analysis methodology inclusive of the way it's been modeled, the input assumptions. Things that are taken credit for are typically, only safety-related mitigation capabilities are credited. For instance, our steam to atmosphere system, which is a control system, is not credited in this analysis, things that would help mitigate it that realistically do exist there.

So although the margin to the regulatory limit for that deterministic evaluation is small, the real margin to plant conditions is actually quite appreciable. And we have seen that when we compare it to an event that, you know, does happen, like a reactor trip, you know, something we can compare it to in our experience bank. So I think there is margin there, but we do analyze it in safety analysis space

very conservatively to make sure that, even if one parameter perhaps is in a less realistic or conservative direction, that's easily accounted for in actual plant response that would be experienced. And, therefore, we have that assurance that we meet the regulatory acceptance criteria.

MR. HALE: And this is Steve Hale, FPL. And the other item that we're not mentioning is we also are not allowed to take credit for the reactor trip on turbine trip. We totally disregard that. That's avoided. This particular event, you know, has a lot of assumptions in it that skew it to maximize the pressure effect to ensure you do have adequate pressure relief capacity. So when you start stacking all those up, you know, it's going to get pretty close, and it's pretty close even now before the EPU. So I think when you look at this particular event, those things should be taken into account.

CONSULTANT KRESS: I thought when we philosophized on defense in depth that many of those conservatisms were in there, and that's because we weren't sure we could categorize it that well and that we establish an acceptance criteria that knows those conservatisms are in there but you still don't want to get too close to it because you're destroying your

defense in depth. That's what I thought defense in depth meant partly. So I don't lack the argument that's being made. Well, we know it's not going to be that bad.

CHAIR SHACK: No, but we do this all the time in design basis space that, you know, you built in your margin in the ASME code and in the analysis. And so when the containment pressure is 59.9 and the acceptable design pressure is 60, you accept it because, essentially, you've built all the conservatisms into the thing. And so, you know, to me, it would be saying that perhaps this argument would be saying we don't have enough conservatism in the ASME code, and I don't think we really believe that. In this deterministic design basis space we're in, you know, you do carry out the calculations, the decimal points that you don't believe in.

MEMBER SKILLMAN: I accept the explanation that you have provided. But in balance, my mind is saying I'm running 15 degrees hotter on T-hot. I'm running two or three degrees hotter on T-cold. I've got 9,000 some hundred cubic feet, which translates to so many pounds at a density of about 42 and a half pounds a cubic foot, the bulk of it is at some higher temperature. I've got all the metal in the reactor

coolant system, and I've got all the metal in the steam generators, three of them in all the piping at that higher temperature. Now I have a loss of offsite power, and what's holding the line are your main steam safety valves. And if they're not orificed just properly, you're going to go up on the stops on the reactor coolant system. Been there, done that, got the tee shirt.

I'm thinking I understand the conservatisms stacking with each other to give a powerful amount of margin. But this plant is not the same as it was before. This plant is now 20 percent higher than the original, and it's 15 percent higher than it will have been on Thanksgiving Day in 2011 when you add in the extra power in the spring of 2012. And so at that point in my mind, where I'm saying, wow, there is a huge amount of thermal momentum and decay heat that needs to be accommodate, and what they've done is they've decreased the setpoints on the main steam safety valves. They haven't re-orificed. They're using the same flow area. And they're pushing up on the mechanical on the reactor coolant system. And I just communicate that's rankling me. That's all I'm communicating.

MS. ABBOTT: This is Liz Abbott from FPL.

I will note everything else is not equal. I mean, there are other changes, and we've removed the flow stops from aux feedwater so we get some additional aux feedwater flow. You know, we did make the adjustments to the main steam safety valve settings. You know, those do allow us to remove heat sooner, so the integrated heat amount removed is a greater amount. You know, those are examples of some of the things that are done, you know, obviously to try to ensure that we stay within the regulatory framework, the envelope that says perform this analysis in a manner that includes those conservatisms and assumptions and methodology and so forth and satisfy the regulatory limit which has margins in and of itself.

So those are all the factors that obviously made this a challenging event to analyze. There are other things, you know, that were factored in that would help mitigate that, as well, you know, to provide some balance to the impact of the EPU.

MEMBER SKILLMAN: Thank you. Mr. Chairman that's my one comment.

CHAIR SHACK: Final comments? Jack, do you have any final comments?

MEMBER SIEBER: No, I don't.

CHAIR SHACK: Tom?

CONSULTANT KRESS: No, I'll write a report.

MEMBER SKILLMAN: No more.

CHAIR SHACK: Sam?

MEMBER ABDEL-KHALIK: I don't have any other comments, but we need to capture that change in the license condition.

CHAIR SHACK: Yes. Graham?

CONSULTANT WALLIS: Yes. I thought it was a good meeting. I felt both the staff and Florida Power and Light did a good job of presenting and responding to questions. I'm just wondering if I need to write a report because the points I would raise I think the staff is already aware of, like this IORV for instance. I think that's a significant thing, but they're going to look into it more. And boron precipitation, I've always thought there are things a bit hokey about the analysis, but we have approved this kind of thing before on the same basis.

On the debate you just had here, I used to think the way Tom thinks. But then I have been converted to realize that there's a number, and if you're below that number you pass. And it's just like grading an exam or something. There's a certain number you have a right to pass. And it may be close,

but that's the rule. And so I've been sort of converted to being more of a regulator than I originally started out being and looking and saying the margins are too small.

CHAIR SHACK: If there are no other comments, then I'd like to thank everybody. I thought the presentations were very good, both from the staff and from the licensee. It was very interesting. A lot of it is deja vu all over again, but it's always good. We always get reminded of things we thought we knew. And with that, I'll adjourn.

(Whereupon, the foregoing matter was concluded at 4:30 p.m.)

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ACRS Subcommittee on Power Uprates

NRC Staff Review
Turkey Point Units 3 and 4
Extended Power Uprate

December 14, 2011

Opening Remarks

Michele G. Evans
Division Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

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Opening Remarks

- NRC staff effort
  - Pre-application review and public meetings
  - Requests for additional information
  - Audits
- Challenging review areas included:
  - Inadvertent Opening of a PORV analysis
  - Feedwater Line Break analysis
  - Boron Precipitation analysis
  - Emerging issue with fuel thermal conductivity degradation

Introduction

Jason C. Paige
Project Manager
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

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Introduction

- Background
  - ❖ TP EPU Application – October 21, 2010
  - ❖ 2300 to 2644 MWt, 15 % increase (344 MWt)
    - Includes a 13 % power uprate and a 1.7 % MUR
    - 20 % increase above original licensed thermal power
- EPU Review Schedule
  - ❖ Followed RS-001
  - ❖ Linked licensing actions
    - AST – approved June 23, 2011
    - SFP Criticality analysis – approved October 31, 2011
  - ❖ Supplemental responses to NRC staff RAIs and Audits
  - ❖ EPU Implementation

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Topics for Subcommittee

- EPU Overview
- Materials – Steam Generators
- Fuel and Core
- Safety Analyses
- Mechanical and Civil Engineering
- Human Factors

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Turkey Point Units 3 and 4 Extended Power Uprate ACRS Subcommittee Meeting

Safety Analysis

Benjamin Parks and Samuel Miranda
Reactor Systems Branch

Leonard Ward, Ph.D.
Nuclear Performance and Code Review Branch

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Agenda

- Review Procedures
- Focus Areas
- Audits
- Review Results and Recommendations
- Conclusion

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Review Procedures

- Follow Review Standard 001
- Adapt RS-001 for Special Considerations
  - Standard Review Plan does not always apply
  - Regulatory Evaluation was inappropriate for pre-GDC plant; staff re-wrote
  - Careful consideration given to RS-001 Introductory Statement:
    - *Plants will be reviewed against their design basis… no backfitting is approved or intended*

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Focus Areas

- Administrative
- Technical
  - ❖ Main Steam Line Break
  - ❖ Outside-design-basis events
    - Feedwater Line Break
    - Inadvertent Opening of Primary Relief Valve
  - ❖ Emergency core cooling system evaluation

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Administrative Issues

- Resource constraints demanded modification to review approach
  - ❖Point Beach review: 3 reviewers
  - ❖Turkey Point review: 9 reviewers
- Open items resolved at end of review rather than through exhaustive use of RAIs
  - ❖*Point Beach/Watts Bar Lesson Learned*
  - ❖Open items resolved with audits

Main Steamline Break

- MSLB is an ANS Condition IV event
- MSLB results meet Condition II criteria
- Review applied Condition II criteria
- MSLB licensing basis is unchanged
- MSLB remains a Condition IV event

Main Steamline Break

- HFP MSLB (0.65 ft^2)
  - min DNBR > 1.18 & max linear kW/ft < 22.72
- HZP MSLB (1.4 ft^2)
  - min DNBR > 1.40
- HZP MSLB (0.9 ft^2) w/o SL isolation
  - min DNBR > 1.40
- Credible break does not return to critical

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Feedwater Line Break

- FWLB is an ANS Condition IV event
- FWLB is not in the PTN design basis
- FWLB analyses demonstrate:
  - ❖AFW heat removal capability
  - ❖SG low level trip setpoint is effective
  - ❖Natural circulation is not blocked
  - ❖Core remains covered

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Feedwater Line Break

- FWLB analysis was requested
- FWLB analysis results indicate:
  - ❖AFW removes all heat after one hour
  - ❖RCS integrity is maintained
  - ❖RCS water remains subcooled
  - ❖Core remains covered and coolable

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Inadvertent Opening of Primary Relief Valve

- Staff requested IORV analysis to validate requested changes to OTΔT setpoint equation
- IORV analysis demonstrated ample DNB margin
- Results showed strong pressurized insurge at end of event

IORV, Continued

- Staff concerned that pressurizer may fill, causing relief valves to relieve liquid water
- Condition would cause relief valves to fail to reseat, not meeting acceptance criterion
- Licensee produced new analyses showing 4-5 minutes available for operator intervention

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IORV, Continued

- Staff observed simulator exercise of IORV event
- Operator secured spuriously opened power-operated relief valve in 9 seconds
- Staff found analyses acceptable and concluded licensee would intervene before pressurizer would fill
- IORV could be a limiting mass addition type event.
- Staff considering generic communication about pressurizer filling during an IORV event

Boron Dilution

- B Dilution is an ANS Condition II event
- Analyses for all modes are required
- FPL supplied cases for Modes 1, 2 and 6
- Requested analyses for Modes 3, 4, and 5
- Results led to increased shutdown margin (from 1% to 1.77% in Mode 5, and in bottom of Mode 4)

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Emergency Core Cooling System

- Unique aspects of Turkey Point ECCS
- ASTRUM Implementation for Large Break LOCA
- Small Break LOCA Results
- Boric Acid Precipitation Control

Turkey Point ECCS

- Two units, four high-head pumps
- SI signal at either unit starts all four pumps
- Pumps align for injection into affected unit
- ECCS Evaluation credits two pumps
- TS require three pumps operable

ASTRUM Implementation – LBLOCA

- Upper tolerance limit PCT is 2063°F
- Best-estimate PCT is approximately 1650°F
- Input parameter distributions generally exceeded the TS-permitted operating range and were consistent with ASTRUM method

ASTRUM Implementation, cont'd

- Licensee used detailed downcomer model with 9 vertical channels (3-loop plant)
- ECCS bypass appeared to be conservatively modeled
  - Significant for limiting case; PCT at 50 seconds

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ASTRUM Implementation, cont'd

- Staff questioned decay heat modeling
- Decay heat uncertainty is sampled
- 2 out of 5 top PCT cases used greater-than-nominal decay heat
- Other three cases were less-than-nominal
- Staff accepted because early PCT is dependent on stored energy and decay heat approach is in accordance with approved method
- Staff is devoting more attention to decay heat modeling in its realistic review efforts

Small Break LOCA

- Small break results were bounded by large break results with significant margin

Boric Acid Precipitation

- Background
- Large Break LOCA Performance

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Post-LOCA Boric Acid Precipitation

- Turkey Point ECCS Design
  - ❖ Three-loop reactor coolant system
  - ❖ 600 psia accumulators
  - ❖ Low-pressure injection
  - ❖ High head safety injection
    - Terminated upon drainage of RWST
  - ❖ High concentration boric acid makeup tank
- Hot leg break limiting for precipitation
  - ❖ LPSI and HHSI during injection mode provides flushing for first 20 minutes
  - ❖ When RWST empties, HHSI is supplied to the cold leg
  - ❖ All safety injection is then switched to hot leg for flushing flow at 5.5 hours to preclude boric acid precipitation

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Control of Boric Acid

- Large Breaks
  - Reinitiate HHSI prior to precipitation

- Small Breaks
  - ❖ Cooldown RCS to low-pressure cut in -135 psia, *or*
  - ❖ Refill RCS with emergency core cooling
    - Re-establishes single phase natural circulation

Model Assumptions (NRC Staff and Licensee)

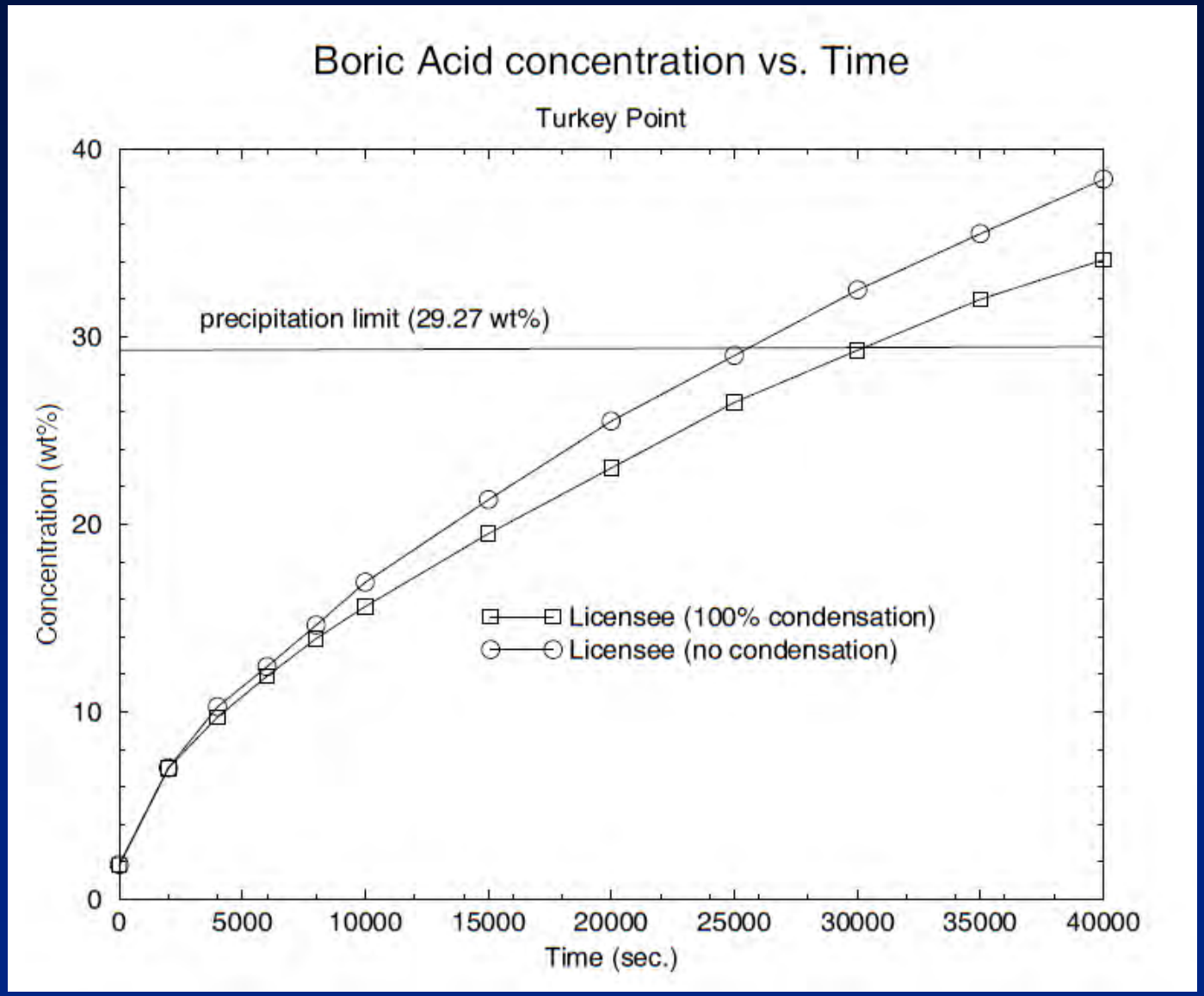
- Mixing volume:
  - ❖Half of lower plenum
  - ❖Core
- 1971 ANS Decay Heat Standard + 20%
- Mixing volume is time-dependent
- RWST and SIT concentrations 2600 ppm
- 100% core boil-off (vapor) condensation

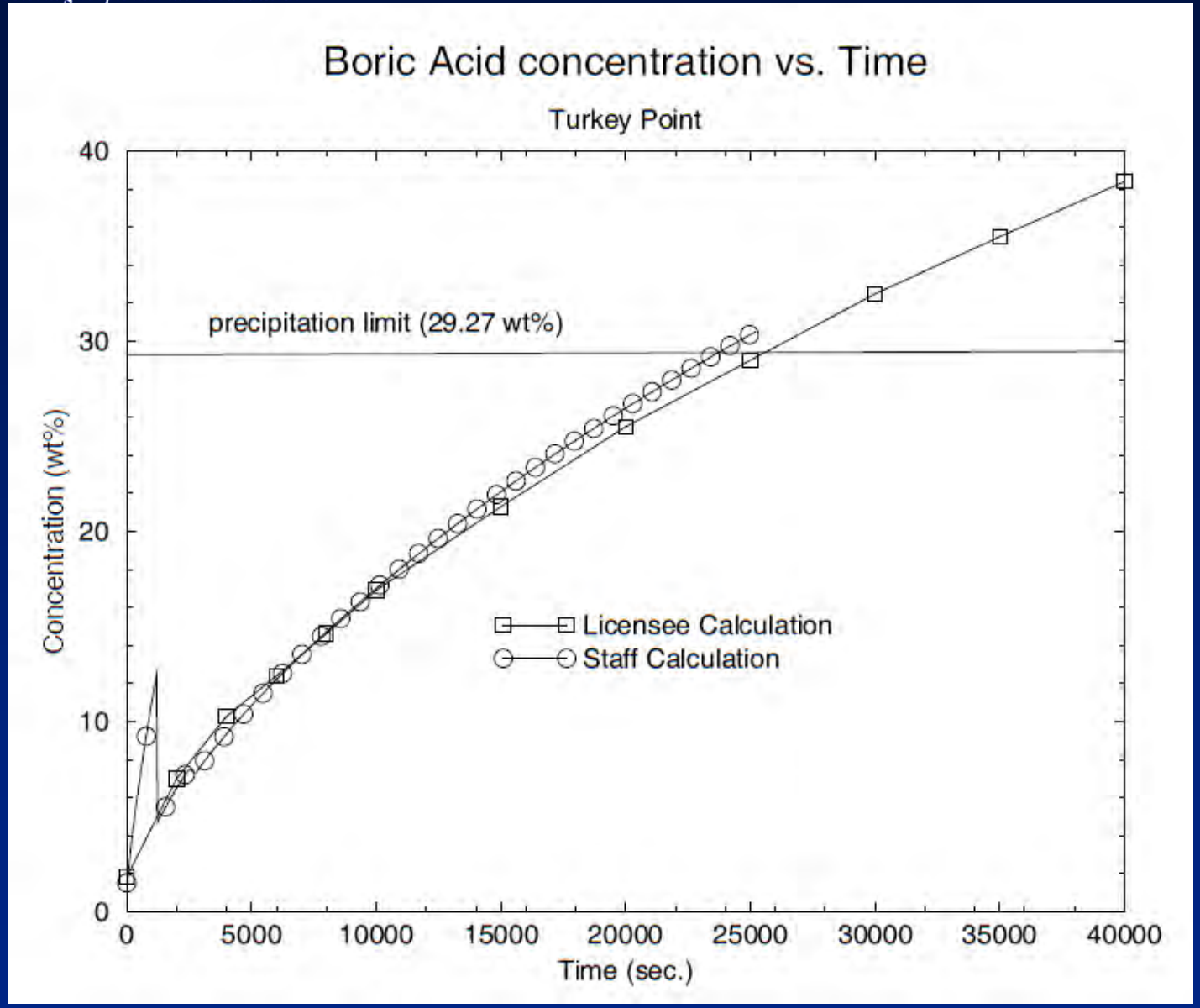
Review Results

- Precipitation timing:
  - ❖ 8.3 hrs (licensee)
  - ❖ 6.7 hrs (staff)
- Staff questioned licensee assumed 100% condensation of core generated vapor
- Licensee recalculated precipitation time (no cond)
  - ❖ Produced earlier precipitation time of 7.1 hrs (vs 8.3 hrs)
    - Set switch to hot leg injection at 5.5 hrs
    - Provides more than one hr margin to precipitation
  - ❖ All cold leg HHSI switched to hot leg at 5.5 hrs
  - ❖ Operators required to perform switch in less than 3 min
  - ❖ A delay of 27.8 min will cause core to uncover and PCT to reach 2200 F
  - ❖ Licensee demonstrated 2 min for operators to perform switch during simulator training exercises

Review Results (cont.)

- HHSI switched between hot and cold leg injection every 16 hrs
- Cannot simultaneously inject into hot and cold sides due to NPSH restrictions


Boric Acid concentration vs. Time
Turkey Point
precipitation limit (29.27 wt%)
Licensee (100% condensation)
Licensee (no condensation)
Concentration (wt%)
Time (sec.)
0
10
20
30
40
0
5000
10000
15000
20000
25000
30000
35000
40000


Boric Acid concentration vs. Time
Turkey Point
precipitation limit (29.27 wt%)
Licensee Calculation
Staff Calculation
Concentration (wt%)
Time (sec.)
0
10
20
30
40
0
5000
10000
15000
20000
25000
30000
35000
40000

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Conclusions

- Staff analysis confirmed
  - ❖ Timing for boric acid precipitation
  - ❖ Sufficient margin exists for switch to hot leg injection relative to precipitation time
- Staff identified concerns with timing for boric acid precipitation control
  - ❖ Licensee revised boric acid precipitation analysis with zero condensation of core vapor generation
  - ❖ Operators to be tested annually to assure timely switch to hot leg injection

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Review Conclusion Audit

- Staff concluded review with three audits:
  - ❖Boric acid precipitation analysis and mitigating strategy audit
  - ❖Simulator observation of three events
    - IORV, MSLB, Boric Acid SI swapover
  - ❖Calculation note review
    - ASTRUM, Boron Dilution, IORV, MSLB, Control Rod Ejection, FWLB

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Audit Results

- Calculations were performed acceptably
  - ❖ Licensee demonstrated that additional sensitivity studies had been performed that were not discussed in RAI responses
  - ❖ Licensee provided comparisons to other plants' results to explain discrepancies
  - ❖ Unusual assumptions were justified
- Credited operator actions were reasonably modeled in safety analyses

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Open Items Resolved

1. Boron Dilution: Licensee provided additional justification for charging flow assumptions in lower mode analyses.
2. RCCA Ejection Accidents: Licensee compared cycle-specific to analytic values to Turkey Point and another plant to validate Turkey Point results.
3. Inadvertent Opening of Pressurizer Relief Valve: Staff observed simulator action to mitigate event; operators responded in timely fashion and mitigating actions were simple.

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Open Items Resolved

4. Large Break LOCA:
   - Licensee provided additional plots of two-phase flow in downcomer to demonstrate emergency core cooling bypass phenomena.
   - Licensee provided extended plots of downcomer and core liquid levels to show long-term stable behavior
   - Licensee clarified ASTRUM treatment of decay heat.

Open Item: Fuel Storage

- Licensee supplemented EPU application on November 9, 2011, changing fuel storage TS
- Licensee will be providing additional information

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Overall Review Results/Recommendations

- Safety analysis results acceptable for licensing basis events
- Licensee provided acceptable analyses for outside-design-basis events
- Staff identified several topical areas for generic pursuit:
  - Some revisions/adaptations for RS-001
  - Mass addition associated with IORV may necessitate generic communication
  - Staff is increasing attention to decay heat modeling in realistic ECCS evaluation
- Boric acid control analyses acceptable, but licensee needs to identify recovery strategy to ameliorate need to cycle between hot and cold leg injection indefinitely

Conclusion

- Staff finds that FPL's proposal for an EPU, for Turkey Point Units 3 and 4, is adequately supported by safety analyses

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Fuel Thermal Conductivity Degradation

- Staff recently learned that effects of fuel thermal conductivity degradation were quantified in an ASTRUM analysis
- Staff requested that FPL address effects in Turkey Point analyses
- Staff will continue to follow FPL's resolution

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Fuel Thermal Conductivity Degradation

- Staff released Information Notice about issue
- Turkey Point is not the only affected plant
- FPL's efforts do not affect staff conclusions with respect to EPU request

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QUESTIONS

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Turkey Point Units 3 and 4
Extended Power Uprate
ACRS Subcommittee Meeting

Mechanical & Civil Engineering Review

Chakrapani Basavaraju, Ph.D.

Mechanical & Civil Engineering Branch

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Review Scope

- NRC staff reviewed the impact of the EPU on the structural integrity of the SSCs:
  - Pressure-retaining components and their supports
  - Reactor pressure vessel and supports
  - Control rod drive mechanisms
  - Steam generators and supports
  - Reactor coolant pumps and supports
  - Pressurizer and supports
  - Reactor pressure vessel internals and core supports
  - Botom Mounted Instrumentation (BMI) Thimble Guide Tubing and Supports
  - Seismic and dynamic qualification of mechanical and electrical equipment.

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Review Results

- EPU increases the steam and feedwater flow rates by approximately 15%. Hot leg & Cold leg temperatures increase by 9° F & 2.6^{o} F respectively
- Piping systems that are mainly affected by the EPU include the following:
  - Main Steam, Condensate, Feedwater, Extraction Steam and Heater Drains.
  - These systems required piping and pipe support modifications and/or equipment replacement/ modification/addition to accommodate EPU conditions.
- Structural evaluations of SSCs (including proposed modifications) at EPU conditions employed current plant design basis methodology and acceptance criteria
- Structural evaluations met design basis code allowable values

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Review Results-RPV support Evaluation

- The licensee attempted to utilize the Certified Material Test Reports (CMTR) yield strength value for EPU evaluations for faulted load combination
- The staff did not agree with the licensee in using CMTR values in design basis qualification and requested that the licensee utilize code based minimum yield strength value rather than the CMTR value
- The licensee re-calculated the RPV support component allowable loads based on the code based yield strength, and demonstrated the structural integrity of the RPV support components for the faulted condition.

Review results

- As a part of the EPU Power Ascension Test Plan, the licensee will monitor the steady state flow induced vibrations are not detrimental to the plant, piping, pipe supports, or connected equipment
- The methodology for monitoring and evaluation of the vibration is based on ASME OM-S/G-2007 Part 3.
- Baseline data will be collected at CLTP (approx. 87%EPU)
- Piping vibrations at various power levels will be compared with level 1 and level 2 acceptance criteria

License Condition related to SFP Supplemental Heat Exchanger

- To maintain current design limits at EPU conditions, a supplemental heat exchanger will be added to the cooling loop of spent fuel pool for each unit
- The NRC staff's review of the EPU LAR identified that the structural design and analysis of spent fuel pool supplemental heat exchanger (SPF suppl HX) associated modifications at EPU conditions had not been completed
- Therefore, the staff has imposed the following license condition

SFP Suppl. HX License Condition

License Condition

- Prior to the use of additional cooling capacity from the supplemental spent fuel pool heat exchanger, the licensee shall confirm to the NRC staff that the design and structural integrity evaluations associated with the modifications related to the SFP suppl. HXs are complete, and that the results demonstrate compliance with appropriate FSAR and code requirements
- As part of the confirmation, the licensee shall provide a summary of the structural qualification results of the piping, pipe supports, supplemental heat exchanger supports, and the inter-tie connection with the existing heat exchanger for the appropriate load combinations along with the margins

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HELB Methodology Overview

- Current Turkey Point licensing basis requirements related to HELB are based on the Giambusso AEC Letter criteria (1972) for systems outside Containment & remain the same for EPU.

- The licensee is continuing the same HELB methodology for EPU that was previously used by the licensee for the CLB prior to EPU, as well as for license renewal.

- Acceptance criteria based on compliance with Turkey Point General Design Criterion (GDC) 40

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HELB Methodolgy Review

- Identification of High Energy Lines
  - ❖ High Energy Line Criteria is based on Temperature (exceeds 200°F) and Pressure (exceeds 275 psig)
  - ❖ Six systems (MS, FW, AFW, SGR Blowdown, CVCS, & RHR) meet the High Energy Line Criteria
- Existing design of SSCs not impacted by plant mods remain acceptable to protect safety related SSCs from the effects of pipe whip & jet impingement loading for EPU
- For SSCs affected by plant mods, required mods will be installed prior to the implementation of EPU to address rupture locations & associated dynamic effects

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Replacement of Sixth FW Heater & Nozzle Modification in support of the EPU

- In accordance with the HELB criteria, the licensee postulated terminal end breaks at the discharge nozzles of the replaced sixth FW heaters
- The discharge nozzle size increased from an 18-inch diameter to 24 inches, which resulted in an increase in the jet's zone of influence from 13.5 feet to 18 feet for EPU conditions

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Replacement of Sixth FW Heater & Nozzle Modification in support of the EPU (cont'd)

- The licensee performed walkdowns encompassing an 18 foot zone of influence around the 6th FW Heater Outlet Pipes and identified equipment important to safety
- Three safety-related pressure transmitters in Unit 3 and five safety-related pressure transmitters in Unit 4 (located within the main steam valve platform trestle area) may be influenced by a circumferential FW pipe rupture at the outlet nozzle terminal ends due to their close proximity to the 6th FW Heaters HELB zone of influence

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Replacement of Sixth FW Heater & Nozzle Modification in support of the EPU (cont'd)

- To protect these safety related components, new deflector shields will be installed on the FW outlet piping at the postulated circumferential break locations at each of the number 6 FW Heater outlet nozzles
- These shields are designed to redirect jet forces and guides stream in a direction away from the safety-related equipment
- The staff finds that the licensee has adequately addressed and evaluated the terminal end break at the outlet nozzle of 6th FW Heater

Conclusions

Based on the review of the licensee's evaluations, the staff concluded that reasonable assurance has been provided to ensure that plant systems, structures, and components important to safety are structurally adequate to perform their intended design functions under EPU conditions.

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QUESTIONS

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Turkey Point Units 3 and 4 Extended Power Uprate ACRS Subcommittee Meeting

Human Factors Review

George W. Lapinsky

Health Physics and Human Performance Branch

Emergency and Abnormal Operating Procedures

- Procedure EOP-ES-1.3, Transfer to Cold Leg Recirculation, and
- Procedure EOP-ES-1.4, Transfer to Hot Leg Recirculation,

  will be changed to direct the use of two (2) High Head Safety Injection (HHSI) pumps (previously 1 HHSI pump) and
- Attachment 1, Concurrent Cold Leg and Hot Leg Recirculation, will be deleted.

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Procedures, continued

The licensee estimated that the addition of an action to start a second HHSI pump adds ten seconds to this action sequence. Additionally, the time limit that HHSI flow can be interrupted during switchover to hot leg recirculation is being reduced from 10 minutes to 3 minutes. Simulator validation of the one pump configuration demonstrated that the action sequence takes less than 2 minutes. Adding 10 seconds will still allow sufficient time to complete the action sequence in 3 minutes or less.

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Human-System Interface Changes

- Changes are extensive but minor, e.g., calibration, updated range, scaling, replace indicator face plates, update indicator banding.
- EHC turbine controls upgrade
- All HSI modifications in accordance with NUREG-0700 guidelines.

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Training

- The proposed training will focus on the Technical Specification changes, procedure changes, and plant modifications, during the training cycle prior to the EPU outage.
- Simulator will be upgraded on a schedule that allows for planned training.

Conclusion

FPL has:

(1) appropriately accounted for the effects of the proposed EPU on their personnel, and

(2) taken appropriate actions to ensure that operator performance is not adversely affected by the proposed EPU.

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QUESTIONS

Public Comments

Committee Guidance Comments

Adjourn

Turkey Point
Extended Power Uprate (EPU)
ACRS Subcommittee

December 14, 2011

Agenda

- **EPU Overview**
  - Introduction..... Mike Kiley
  - Plant Changes..... Steve Hale
  - Power Ascension Testing ..... Sam Shafer
- **Materials**
  - Steam Generators ..... Steve Hale
- **Analyses**
  - Fuel and Core ..... Carl O'Farrill
  - Safety Analysis ..... Carl O'Farrill
- **Acronyms**

FPL.

Turkey Point

- Located 25 miles south of Miami, Florida
- Pressurized Water Reactor (PWR)
- Westinghouse 3 Loop Nuclear Steam Supply System (NSSS)
- Westinghouse Turbine Generator
- Architect Engineer – Bechtel Power, Inc.
- Each Unit output 795 MWe gross

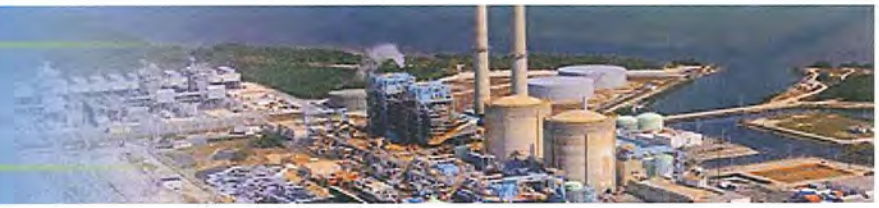
FPL

Turkey Point

- Original operating licenses issued in 1972 for Unit 3 and 1973 for Unit 4
- Steam Generators (SGs) replaced in 1982 and 1983
- Two additional safety grade Emergency Diesel Generators installed in 1991
- Renewed Operating Licenses issued in 2002
- Reactor Vessel Heads replaced in 2004 and 2005

FPL.

Turkey Point



- **Thermal Power**
  - Original Licensed Thermal Power 2200 MWt
  - Current Licensed Thermal Power 2300 MWt
    -- Stretch Uprate 104.5% (1996)
  - EPU Thermal Power 2644 MWt
    -- Implement 2012 - 2013

FPL

FPL is requesting approval for a 15% power level increase for the Turkey Point units

- **15% increase in licensed core power level (2644 MWt)**
  - 13% Power Uprate
  - 1.7% Measurement Uncertainty Recapture
  - (2300 x 1.13) x 1.017 ~ 2644 MWt
- **Attributes of the Turkey Point EPU**
  - Classic NPSH requirements for ECCS pumps are met without credit for containment overpressure
  - No fuel design changes for EPU
  - License Amendment Request 196: Alternative Source Term (AST)
    - -- Radiological accident analyses performed at EPU conditions
    - -- License amendment issued in June 2011
  - License Amendment Request 207: Spent Fuel Pool Criticality
    - -- Analyses included EPU fuel conditions
    - -- License amendment issued in October 2011

FPL.

FPL is requesting approval for a 15% power level increase for the Turkey Point units

- **Grid stability studies have been completed and approved for the EPU full power output**
- **Final required modifications to support EPU operation will be implemented in 2012 - 2013**
  - Spring 2012 outage for Unit 3
  - Fall 2012 outage for Unit 4

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 Turkey Point 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 2002-3, Guidance on the Content of Measurement Uncertainty Recapture Uprate Applications***

FPL

Plant Modifications

- General Approach
- Plant Parameters
- Modifications

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 2652 MWt (core + pump heat)
- Changes in major parameters addressed for Balance of Plant (BOP) systems and components
- Hydraulic analysis 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	1996 Uprate	EPU	EPU Change
Core Power (MWt)	2200	2300	2644	+344
RCS Pressure (psia)	2250	2250	2250	0
Taverage (°F)	574.2	571.2(1) – 577.2	570.0 – 581.5	-1.2 / +4.3
Vessel Inlet (°F)	546.2	540.4 – 546.6	535.5 – 549.2	-4.9 / +2.6
Vessel Outlet (°F)	602.3	602.0 – 607.8	604.5 – 616.8	+2.5 / +9.0
Delta T (°F)	56.1	61.6 – 61.2	69.0 – 67.6	+8.4 / +6.4
Thermal Design Flow (gpm/loop)	89,500	85,000	86,900	+1,900
Core Bypass (%)	4.5	6.0	6.3	+.3
Steam Pressure (psia)	785	701 - 832	701 - 822	0 / -10
Moisture Carryover (maximum, %)	0.25	0.25	0.25	0
Steam Mass Flow(10^6 lb/hr)	9.60	10.13 – 10.17	11.59 – 11.64	+1.46 / +1.47

(1) Some analyses consider T_{avg} of 566.2°F for an end of cycle coastdown

FPL

Modifications will be made in support of the Safety Analysis

- Nuclear Steam Supply System (NSSS) setpoints
- Pressurizer Level Program and Safety Valve lift settings
- Hot leg injection flow path
- Emergency Containment Coolers auto start logic
- Main Steam Safety Valve setpoint changes
- Main Steam Isolation Valve (MSIV) and Main Steam Check Valve (MSCV) upgrades
- Modify / Install Feedwater Isolation Valves
- Install Leading Edge Flow Measurement (LEFM) System
- Refurbish Auxiliary Feedwater Pumps
- Remove Auxiliary Feedwater Control Valve travel stops
- Safety Related piping support modifications
- Jet impingement shields
- Technical Support Center shielding modifications
- Install Additional Spent Fuel Pool Cooling capacity

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Modifications will be made in support of power generation at the EPU power level

- **Steam Path**
  - Replace High Pressure Turbine
  - Electro Hydraulic Control (EHC) system and control valves
  - Digital Turbine controls
  - Replace Moisture Separator Reheaters (MSRs)
- **Condensate and Feedwater**
  - Replace Main Condensers and condenser cleaning system
  - Replace Condensate Pumps and Motors
  - Replace Feedwater Pump rotating assemblies
  - Modify Main and Bypass Feedwater Control Valves / Actuators
  - Replace High Pressure Feedwater Heaters
  - Replace Gland Steam Condenser and Piping
  - Steam Jet Air Ejector Tube bundle Replacement

- Continued on next page -

FPL.

Modifications will be made in support of power generation at the EPU power level (continued)

- **Heater Drains**
  - Modify Heater Drain Piping
  - Heater Drain System Control Valve and Digital Upgrade
- **Other Balance of Plant items**
  - Balance of Plant (BOP) setpoints
  - BOP Piping Supports
- **Auxiliary Support Systems**
  - Replace Turbine Plant Cooling Water Heat Exchangers
  - Replace Control Rod Drive Mechanism Fan motors and coolers

- Continued on next page -

FPL.

Modifications will be made in support of power generation at the EPU power level (continued)

- **Electrical Modifications**
  - Generator upgrades including
    - -- Stator rewind
    - -- Rotor replacement
    - -- New current transformers
    - -- New Hydrogen coolers
    - -- New Exciter air coolers
  - Iso-Phase Bus Duct modifications
  - Main Step-up Transformer Cooling and Tap Changer modifications
  - Replace Unit Auxiliary Transformers
  - Switchyard Modifications

FPL.

A systematic approach was used to develop the Power Ascension Test

Power Ascension Testing - Preparation

- **Test Objective Development**
  - Satisfactory Equipment Performance
  - Ensure Integrated Plant Response
  - Careful, Monitored Approach to EPU Power
  - Meet established requirements
- **Roles and Responsibilities Clearly Defined**
  - Power Ascension Test Program Guidelines
- **Test Plan and Implementing Test Procedure govern the power ascension testing**
  - Startup Test Program Guidelines
- **Incorporated Industry Benchmarking**

FPL.

A systematic approach was used to develop the Power Ascension Test (continued)

Power Ascension Testing - Approach

- Expected values for each data set have been determined by Engineering
- Base line data will be taken at each plateau
- The Master Test Plan is coordinated with the normal power operating procedure for power escalation
- A test report will be generated at each power plateau

FPL.

A systematic approach was used to develop the Power Ascension Test (continued)

Power Ascension Testing – Approach (cont'd)

- **No large plant transient testing will be performed**
  - Analytical methods and training facilities adequately simulate large transient events
  - LOFTRAN code evaluated large operational plant transients and has been benchmarked against data from several plant transients
  - Plant Operators will be trained on large transient event using the simulator

FPL.

Power Ascension Testing will be performed in a controlled methodical manner under the direction of Senior Reactor Operator

Power Ascension Testing - Approach

- **EPU testing plateaus include:**
  - Performance / completion of Preoperational Test Procedures
  - Data collection
    - -- Piping vibration & thermal expansion
    - -- Radiation monitoring
    - -- BOP data collection
    - -- NSSS data collection
  - Control system stability dynamic tuning
  - Data Analysis
  - Test Review Board and Plant Safety Committee to review and approve test reports.

FPL.

Power Ascension Testing – Test Plan

Test Description	Prior to Startup	Rated Thermal Power-% of 2644 MWt												
		Allowance +0, -5%								Allowance +0%, -1%				
		0	5	20	30	40	50	75	87	89	92	95	98	100
NSSS data collection				X	X		X	X	X	X	X	X	X	X
BOP data collection				X	X		X	X	X	X	X	X	X	X
LEFM data collection				X	X		X	X	X	X	X	X	X	X
Transient data collection				X	X		X	X	X	X	X	X	X	X
Core Map - Power distribution and COLR Parameters							X	X(1)	X	X(1)	X(1)	X(1)	X(1)	X
NSSS Calorimetric and Power Range Channel Adjustment				X	X		X	X	X	X	X	X	X	X
Incore - Excore Axial Offset Calibrations						X			X					X
Reactor Coolant System flow measurement (calorimetric)														X
Load Changes - 10% Ramp to verify system response					X								X	
Turbine Control System checks and testing	X		X	X			X	X	X	X	X	X	X	X
Turbine Stop Valve/Governor Valve and Intercept Valve Testing						X								
Steam generator Level/Feedwater Flow Dynamic Testing					X				X			X		
Heater Drain System Control System checks and testing	X						X	X	X	X	X	X	X	X
Vibration and Thermal Expansion checks and testing	X				X		X	X	X	X	X	X	X	X
Plant Radiation Survey									X					X
Plant Temperature Survey									X					X
Equipment Thermography Checks and Temperature Profiles					X		X	X	X	X	X	X	X	X
System and Component post modification testing and monitoring	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Feedwater Heaters Optimization and Performance Monitoring							X						X	
Condenser Performance Test														X
Generator Power System Stabilizer					X							X		

1. If required.

FPL

Acceptance criteria and actions have been established for the test

Power Ascension Testing
Acceptance Criteria and Actions

- **Acceptance Criteria (Level 1):**
  - A limit associated with plant safety
- **Actions if Level 1 criterion not met:**
  - Secure Testing
  - Reduce power to last known safe condition
  - Initiate an evaluation of condition
  - Retest only once condition corrected
  - Document problem and resolution
  - Obtain Plant Safety Committee review and approval prior to continuing

FPL

Acceptance criteria and actions have been established for the test (continued)

Power Ascension Testing
Acceptance Criteria and Actions (cont'd)

- **Functional Criteria (Level 2):**
  - A limit associated with design expectations
- **Actions if Level 2 criterion not met:**
  - Place test on hold and confirm plant is in a safe condition
  - Evaluate the condition and implement required actions
  - Repeat testing as required to satisfy Level 2 criterion
  - Document problem and resolution
  - Obtain Test Review Board concurrence prior to continuing

FPL

Agenda

- **EPU Overview**
  - Introduction..... Mike Kiley
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- **Materials**
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  - Safety Analysis ..... Carl O'Farrill
- **Acronyms**

FPL

Analyses demonstrated acceptable Steam Generator tube wear at EPU conditions

Steam Generator Analysis Results

Parameter	Acceptance Criteria	Results[3]
Fluidelastic stability ratio	<1.0	Met with margin
Amplitude of tube vibration due to turbulence no greater than ½ of the gap between tubes (.179 in)[1]	<0.09 in	Met with margin
Demonstrate that unacceptable tube wear will not occur after the EPU[2]	<0.020 in	Met with margin
FIV-induced tube stresses remain below the fatigue endurance limit of the material	<20 ksi at 1E11 cycles	Met with margin

Notes:

1. This considers the worst-case scenario that the adjacent tubes are moving 180 degrees out of phase
2. 40% wear depth for the Model 44F steam generators would be 0.4 x 50 mils = 20 mils
3. Results are provided in the Turkey Point EPU License Amendment Request 205, Attachment 4, Section 2.2.2.5.5.5 (pages 2.2.2-57 and 58)

FPL.

Steam Generator parameters at EPU conditions are comparable to the current industry operating experience

Steam Generator Comparison

Plant	Steam Generator Model	Velocity (Downcomer Tube Entrance) [ft/sec]	Volumetric Flow Rate U-Bend [ft^3/sec]	Velocity (V) (U-Bend Entrance) [ft/sec]	Mixture Density (ρ) [lb/ft^3]	ρV^2 (U-Bend) [$lb/ft\text{-}sec^2$]
Turkey Point 3 & 4	44F	12.26	731	15.1	4.52	1031
Point Beach 1	44F	12.02	880	18.2	3.60	1190
Point Beach 2	Δ47	9.68	728	13.4	4.27	995
Kewaunee	54F	12.09	817	15.1	5.11	1160
Indian Point 2	44F	None given	783	16.2	3.80	995
Indian Point 3	44F	12.12	818	16.9	4.06	1154

Operating experience shows the expected tube wear is acceptable for uprate condition

FPL

Based on excellent Steam Generator operating performance no tube wear issues are expected at EPU conditions

- Many years of operating experience with no indication of tube vibration problems with Steam Generators comparable to Turkey Point
- Periodic Steam Generator tube inspections have provided no indication of unusual tube wear
- Although not anticipated by analysis, on-going Steam Generator tube inspections will provide early indication if problems were to occur

FPL

Agenda

- **EPU Overview**
  - Introduction..... Mike Kiley
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- **Materials**
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- **Analyses**
  - Fuel and Core ..... Carl O'Farrill
  - Safety Analysis ..... Carl O'Farrill
- **Acronyms**

FPL.

Fuel design maintains margin to limits

Fuel Design

- **Advanced fuel design (15x15 Upgrade) implemented in previous cycles, which utilizes intermediate flow mixer grids**
- **Minor changes in fuel rod loading to accommodate higher fission gas release associated with EPU**
  - Annular blanket size increased from 6 to 8 inches
  - ZrB_2 Integral Fuel Burnable Absorber concentration remains 1.25x
- **Peak Rod and Assembly burnup will be maintained within current limits**

FPL

Margins to key safety parameters are maintained

Core Design

- **Core design limits are reduced to offset effect of EPU and maintain margins to fuel design limits**
  - Hot Channel Enthalpy Rise Factor ($F_{\Delta H}$) core design limit reduced from 1.70 to 1.65
  - Axial offset operating band is reduced and,
  - The Heat Flux Hot Channel Factor (F_Q) is reduced from 2.5 to 2.4
- **Normal incore fuel management methods utilized to meet reduced limits**
  - Feed enrichment & feed batch size
  - Burnable absorber placement
  - Core Loading pattern

FPL

Margins to key safety parameters are maintained (continued)

Core Design Changes (continued)

- **Margin to key safety parameter limits maintained**
  - Variations within normal cycle variations
- **Shutdown Margin requirement is not changed for at-power operation**
  - Larger Doppler power defect at EPU conditions, but Shutdown Margin (SDM) remains considerable
- **RCS Boron requirements remain within system capability**
  - Boron concentrations increase by ~ 300 ppm for Mode 6
  - Keff < 0.95 for Mode 6

Margins to key safety parameters are maintained

FPL.

Improved safety analysis methods were utilized to assess impacts of EPU conditions

- **Code and Methodology Changes**
  - WCOBRA/TRAC with ASTRUM – Large Break LOCA
  - RETRAN: Non-LOCA Transients
  - LOFTTR2: Steam Generator Tube Rupture
  - VIPRE: DNB analysis of the nuclear fuel
  - GOTHIC: LOCA and Steam Line Break (SLB) containment integrity analyses

NRC pre-approved codes and methodologies were used

FPL

Safety analyses are conservative and improved

- **Key changes beneficial to safety analysis**
  - Improved methods
  - Reduction of peaking factors (Heat Flux Hot Channel Factor (Fq) and Hot Channel Enthalpy Rise Factor ($F_{\Delta H}$))
  - Reduction in axial offset operating limits
- **Conservative inputs/assumptions**
  - Conservative physics parameters
  - Bounding plant operating parameters
  - Conservative trip setpoints
- **Conservative analysis DNBR limit**
  - Safety Analysis Limit (SAL) for DNBR is set conservatively to maintain margin to the DNBR design limit

FPL

Safety analyses include appropriate input changes

- Main Steam Safety Valves (Banks 3 and 4) nominal setpoints revised from 1115 psig/1130 psig to 1105 psig
- Pressurizer Safety Valve nominal setpoint revised from 2485 psig to 2465 psig
- SG Water Level Low-Low nominal setpoint revised from 10% to 16%
- Low-Low SG Water level AFW Pump Start Delay Time revised from 120 seconds to 95 seconds
- Full AFW Flow Rate revised from 310 gpm to 373 gpm
- RCS Thick Metal Mass Heat Transfer Model credited (NRC approved)

FPL.

Safety analyses include appropriate input changes (continued)

- High Neutron Flux Reactor Trip Setpoint revised from 118% to 115%
- Revised OTΔT and OPΔT equations
- Lead Time constant added for Measurement of Steam Line Pressure
- Two of four available HHSI pumps credited for LOCA
- RCS flow requirement increased from 265,000 gpm to 270,000 gpm
- Minimum Accumulator and RWST boron concentration requirement revised from 1950 ppm to 2300 and 2400 ppm, respectively

FPL

Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria

Analysis Methodologies

Method	Pre- EPU	EPU
Non-LOCA	LOFTRAN Computer Code	RETRAN Computer Code
	Point Kinetics Neutronics for DNB Analyses	Point Kinetics Neutronics for DNB Analyses
	No Thick Metal Mass Credited	Methodology for Reactor Coolant System Thick Metal Mass Heat Transfer Model
	Full Power Steam Line Break not in CLB	Full Power Steam Line Break Analyzed

Codes and methodologies are NRC approved

FPL.

Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
Decrease (Loss) in RCS Flow (Reduced Primary Cooling)	Loss of Flow (Cond III) 1) WRB-1 DNB Correlation 2) ABB-NV DNB Correlation non-mixing vane grid spans	DNBR (SAL*) **Upgrade Fuel** ≥1.40/1.40 (typical/thimble)	1.698/1.712
		DRFA Fuel ≥1.50/1.50 (typical/thimble)	1.743/1.710
	Locked Rotor (Cond IV)	RCS Pres ≤ 2748.5 psia Rods-in-DNB ≤ 15%	2694.1 psia 0%
Overheating (Reduced Secondary Cooling)	Loss of Load (Cond II)	RCS Pres ≤ 2748.5 psia MSS Pres ≤ 1208.5 psia	2746.6 psia 1197.1 psia
	Loss of Feedwater (Cond II)	Przr Mix Vol ≤ 1300 ft^3	1198.5 ft^3
	Loss of AC Power (Cond II)	Przr Mix Vol ≤ 1300 ft^3	1185.9 ft^3
	ATWS	RCS Pres ≤ 3215 psia	3174.5 psia

* Safety analysis limit DNBR has margin compared to the DNBR design limit

FPL

Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
Overcooling	HFP MSLB (Cond III or IV)	DNBR (SAL*) **Upgrade Fuel** ≥1.40	1.836
		DRFA Fuel ≥1.50	2.117
		LHR ≤ 22.72 kW/ft	22.68 kW/ft
	HZP MSLB (Cond IV) WLOP DNB Correlation	DNBR (Correlation Limit) **Upgrade Fuel** ≥1.18 (typical/thimble)	1.464/1.411
		DRFA Fuel ≥1.18 (typical/thimble)	1.382/1.328
		LHR ≤ 22.72 kW/ft	22.198 kW/ft

* Safety analysis limit DNBR has margin compared to the DNBR design limit

FPL.

Conservative analysis methods applied for non-LOCA events with all results meeting acceptance criteria (continued)

	Event	Criteria	Result
Reactivity Addition	Rod Withdrawal @ Power (Cond II)	DNBR (SAL*) ≥ 1.40 RCS Pres ≤ 2748.5 psia	1.48 2740.92 psia
	Rod Ejection (Cond IV)	Fuel Enthalpy ≤ 200 cal/g Fuel Melt (at hot spot) ≤ 10%	172.94 cal/g 3.37%

* Safety analysis limit DNBR has margin compared to the DNBR design limit

FPL.

Small Break LOCA safety margin is assured by key changes

Parameter	Pre - EPU	EPU
Analyzed Core Power (MWt)	2300	2644
Hot Channel Enthalpy Rise Factor [$F_{\Delta H}$]	1.70	1.65
Axial Offset (%)	20	13
Steam Generator Tube Plugging Level (%)	20	10
HHSI	One HHSI Pump	Two HHSI Pumps

FPL.

Small break LOCA analysis performed using NRC-approved NOTRUMP evaluation model demonstrated acceptable results

	Pre - EPU	EPU	Limit
Limiting Break Size	3-Inch	4-Inch	-
PCT (°F)	1688	1231	2200
Maximum Transient Local Oxidation (%)	2.02	0.07	17.0
Maximum Core-Wide Oxidation (%)	< 1.0	< 1.0	1.0

FPL

Large Break LOCA Analysis Performed Using NRC Approved Best Estimate ASTRUM with results meeting acceptance criteria*

10 CFR 50.46 Requirement	Pre-ASTRUM/EPU Value	EPU Value	Acceptance Criteria
95/95 Peak Cladding Temperature (°F)	2040	2064	< 2200
50th Percentile Peak Cladding Temperature (°F)	1612	1638	-----
95/95 Maximum Local Oxidation (%)	11	4.25	< 17.0
95/95 Core Wide Oxidation (%)	0.70	0.43	< 1.0
Coolable Geometry	Long term cooling is maintained via operator actions. No impact on coolable geometry.		
Long-Term Cooling			

* Evaluating effect of Thermal Conductivity Degradation (TCD)

FPL

The effects of fuel pellet thermal conductivity degradation (TCD) are being assessed

- Data from experiments conducted at the Halden test facility in the 1990's indicated that TCD at higher burnups may not be sufficiently accounted for in industry nuclear fuel analysis codes
- Information Notice 2009-23, Nuclear Fuel Thermal Conductivity Degradation, indicated codes approved by NRC before 1999 may not adequately address this effect
- Previous assessments indicated sufficient conservatism existed within the current Westinghouse fuel performance methods to compensate for the TCD effect
- Westinghouse is developing an upgraded version of the PAD code which will explicitly account for TCD to be submitted in 2013 to NRC for approval

FPL

The effects of fuel pellet thermal conductivity degradation (TCD) are being assessed

- **Recent conservative estimates indicate that the impact of TCD on fuel average temperatures may be higher**
  - Assessments continue to indicate that the fuel average temperature at higher burnup remains below the fuel average temperature at zero burnup
- **FPL is addressing the impact of TCD on the Turkey Point EPU safety analyses**

FPL

Preliminary assessment of the impact of TCD indicates acceptable results for Turkey Point EPU analyses

- **Preliminary assessment of the impact of TCD on EPU analyses performed**
  - Fuel thermal hydraulic design
  - Core physics design
  - Fuel rod mechanical design
  - SBLOCA
  - Post LOCA long term cooling analysis
  - Containment pressure for MSLB
  - Radiological consequences
  - SGTR
  - Containment pressure for LBLOCA
  - LBLOCA
  - Non-LOCA

FPL.

Preliminary assessment of the impact of TCD indicates acceptable results for Turkey Point EPU analyses

- **TCD impact on Turkey Point EPU analyses has minimal or no impact on most areas**
- **Additional assessments in progress:**
  - Fuel mechanical design
    - -- Fuel power to melt limit
    - -- Rod internal pressure
    - -- Clad strain/stress/fatigue
  - Safety Analyses
    - -- Locked rotor PCT and DNB analyses
    - -- Rod Ejection
    - -- Rod Withdrawal from Subcritical Conditions
    - -- Main Steam line break
    - -- LBLOCA
- **Preliminary evaluations indicate acceptable results**
- **Analyses being finalized for submittal to NRC in January 2012**

FPL

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➡ **Acronyms**

FPL

Acronyms

AFW	Auxiliary Feedwater
AST	Alternative Source Term
ATWS	Anticipated Transient without Scram
BOP	Balance of plant
CLB	Current Licensing Basis
DNB	Departure From Nucleate Boiling
DRFA	Debris Resistant Fuel Assembly
ECCS	Emergency Core Cooling System
EHC	Electro Hydraulic Control
EPU	Extended Power Uprate
F	Fahrenheit
FΔH	Hot Channel Enthalpy Rise
FQ	Heat Flux Hot Channel Factor
ft	Feet
GPM	Gallons per minute
HFP	Hot Full Power
HHSI	High Head Safety Injection
HZP	Hot Zero Power
in	Inch
Keff	K-effective
ksi	Kilo pounds per square inch
LAR	License Amendment Request
lb/hr	Pounds per hour
LEFM	Leading Edge Flow Meter
LHR	Linear Heat Rate
LOCA	Loss of Coolant Accident
MSCV	Main Steam Check Valve
MSIV	Main Steam Isolation Valve
MSLB	Main Steam Line Break
MSR	Moisture Separator Reheater
MWe	Megawatts electric
MWt	Megawatts thermal
NAMS	Nuclear Assets Management System
NPSH	Net Positive Suction Head
NSSS	Nuclear Steam Supply System
PCT	Peak Cladding Temperature
PNSC	Plant Nuclear Safety Committee
PPM	Parts per Million
Pres	Pressure
PSIA	Pound per square inch - absolute
PWR	Pressurized Water Reactor
RCS	Reactor Coolant System
RIS	Regulatory Issue Summary
RS	Review Standard
RTS	Return to Service
RWST	Refueling Water Storage Tank
SAL	Safety Analysis Limit
SDM	Shutdown Margin
Sec	Second
SG	Steam Generator
SLB	Steam Line Break
V	Velocity
ZrB_2	Zirconium Diboride
ρ	Density

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