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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

March 20, 2008

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARD

(ACRS)

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SUBCOMMITTEE ON POWER UPRATES

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THURSDAY

MARCH 20, 2008

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ROCKVILLE, MARYLAND

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OPEN SESSION

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The Subcommittee met in Open Session at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., Dr. Said Abdel-Khalik, Chairman, presiding.

SUBCOMMITTEE MEMBERS PRESENT:

SAID ABDEL-KHALIK, Chair

MARIO V. BONACA

SANJOY BANERJEE

J. SAM ARMIJO

OTTO L. MAYNARD

NRC STAFF PRESENT:

ZENA ABDULLAHI, Designated Federal Official

CATHERINE HANEY

JOHN G. LAMB

KAMISHAN MARTIN

TONY NAKANISHI

PETER YARSKY

MUHAMMAD RAZZAQUE

RICHARD LOBEL

ALSO PRESENT:

TOM JOYCE

PAUL DAVISON

BILL KOPCHICK

DON NOTIGAN

ED BURNS

PAUL LINDSAY

PAUL DUKE

FRAN BOLGER

TED DelGAIZO

SKIP DENNY

VINCENT ZABIELSKI

BRIAN MOORE

FRANCIS SAFIN

SHELLY KUGLER

TABLE OF CONTENTS

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

(8:30 a.m.)

CHAIR ABDEL-KHALIK: The meeting will now come to order. This is the first day of a two-day meeting of the Advisory Committee on Reactor Safeguards Power Uprates Subcommittee. I'm Said Abdel-Kahlik, Chairman of the Power Uprates Subcommittee's review of the Oak Creek Generating Station Extended Power Uprate Application.

Subcommittee members in attendance are Mario Bonaca, Sam Armijo, Sanjoy Banerjee, Otto Maynard. We also expect Michael Coradini to join us later today. Also in attendance are ACRS consultants, Graham Wallis and tom Kress. ACRS members Jack Sieber and John Stetkar and ACRS consultant Alan Pierce are expected to join us tomorrow.

The purpose of this two-day meeting is to hear presentations by and hold discussions with the Hope Creek licensee, PSEG, the NRC staff, their consultants and other interested persons regarding the proposed EPU. The subcommittee will gather information, analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberations by the ful committee. Zena Abdullahai is the designated federal official for this meeting.

Parts of this meeting will be closed, because the material to be presented is considered proprietary by the Applicant, PSEG and/or its contractors, General Electric-Hitachi and Continuum Dynamics, Incorporated. The proposed times for the closed sessions are identified in the agenda. Attendees who are required to leave during the closed sessions can call 301-415-7360 to obtain a status report as to when they can rejoin the meeting.

We received a request for a teleconference from Mr. Jerry Humphreys who represents the State of New Jersey. A bridge telephone number was made available. I understand that Mr. Humphreys has not signed a proprietary agreement for General Electric-Hitachi and, therefore, cannot participate in today's closed sessions involving GEH proprietary information. However, having signed the relevant propriety agreement with Continuum Dynamics, Incorporated, Mr. Humphreys should be able to participate in tomorrow's closed session, discussions of the steam dryer based on CDI's analyses and methodologies. Please note that the bridge connection is only for listening in.

A transcript of the meeting is being kept and will be made available as stated in the Federal

Register Notice. It is requested that speakers first identify themselves and speak with sufficient clarity and volume so that they can be readily heard. We will now proceed with the meeting, and I call on Ms. Catherine Haney of NRR to start the meeting.

MS. HANEY: Thank you. Good morning. I'm the Director of the Division of Operator Reactor Licensing in the office of Nuclear Reactor Regulation. Over the next two days, you will hear the results of a very thorough review by our staff of the application submitted by Public Service Enterprise Group Nuclear, Limited Liability Corporation, PSEG.

We had frequent communications with the licensee over the last several months including calls, conference calls, meetings, letters, etcetera. We believe that this helped with our thorough review of the application. In addition, there were several rounds of requests for additional information that were issued to the licensee. The RAIs were submitted as they were developed allowing the licensee as much time as possible to review and respond to our RAIs. The input from the licensee was then reviewed by our technical staff.

Some of the more challenging review areas that you will hear about over the next two days are the steam dryer stress analysis and the fuel and core design analysis. As presented in the draft safety evaluation without the steam dryer which was provided to the ACRS on February 14th, 2008, and the steam dryer safety evaluation input which was provided on February 29th, 2008, there are currently no open technical issues. This two-step process was something that we used with the ACRS was unique. Typically, we supply one safety evaluation report. However, to allow sufficient extra time for ACRS to review the application, we did reach an agreement about submitting it in two stages, and we do appreciate your willingness to take it that way.

I'm pleased with the thoroughness of the review conducted by the NRC. The staff had extensive interactions with PSEG on several of these diverse issues, as I've mentioned. And at this point, I'd like to turn the presentation over to my Project Manager, John Lamb, and he'll introduce the discussions for the day.

MR. LAMB: Good morning. My name is John Lamb. I am a Senior Project Manager in the office of Nuclear Reactor Regulation, NRR. I am the Project Manager in the Division of Operating Reactor Regulatory Licensing, DORL, assigned to the Hope Creek

Generating Station, Hope Creek Extended Power Uprate, EPU.

As you know, we only gave you 19 days to review the steam dryer information. The staff realizes the significant this places on the ACRS members. On behalf of the staff, I would like to take this public opportunity to thank the ACRS for accommodating our schedule and reviewing the steam dryer portion on a short turnaround. The staff greatly appreciates the ACRS members' effort in this regard.

To quote the famous mathematician and astronomer, Johannes Kepler, I prefer the sharpest criticism of a single intelligent man to the thoughtless approval of the masses. So this quote brings to mind our purpose over the next two days is to convince you that the staff's safety evaluation, SE, for the Hope Creek EPU provides the following -- one, there is reasonable assurance that the health and safety of the public will not be endangered by the proposed EPU and two, the proposed EPU will be conducted in compliance with the Commission's regulations.

After two days of hearing presentations from the staff and the licensee, we hope that you agree that this will -- agree with this and will recommend to the ACRS full committee on April 10th, 2008 that the proposed EPU amendment be issued and reflect this in your letter report.

fore I go over the agenda, I would like to present some background information related to the staff's review of the proposed Hope Creek EPU. Hope Creek is a boiling water reactor, BWR. The proposed EPU would increase the maximum authorized thermal level from the current licensed thermal power level of 3,339 megawatts thermal to 3,840 megawatts thermal. This represents an approximate 15% increase from the current licensed thermal power.

Hope Creek was granted a measurement uncertainty recapture, MUR, power uprate of 1.4% in Amendment Number 131 dated July 30th, 2001. The MUR changes were based on the installation of the CE Nuclear Power, LLC cross-flow ultrasonic flow measurement system and its ability to achieve increased accuracy in measuring feedwater flow. This MUR increased the power from the original licensed thermal power of 3,293 megawatts thermal to the current licensed thermal power level of 3,339 megawatts thermal. The ACRS did not review this MUR as is the custom with MURs.

On Jule 25th, 1996, the NRC licensed Hope Creek for full power operation at 3,293 megawatts thermal. As you know, Hope Creek would not be the unit with the highest thermal power level if you approve the issuance of the proposed EPU amendment. The units with the highest thermal power in the country are Palo Verde 1, 2 and 3, at 3,990 megawatts thermal which are pressurized water reactors, PWRs. PWR units with the highest thermal power as Susquehanna 1 and 2 at 3,952 megawatts thermal. South Texas Projects 1 and 2, which are PWRs, are rated at 3,853 megawatts thermal. So this proposed EPU would make Hope Creek the eighth highest unit in the country at a licensed thermal power level of 3,840 megawatts thermal.

As far as the method of NRC review, the staff's review for the PSEG application was based on NRC's review standard for extended power uprates. The review standard includes a safety evaluation template as well as matrices that correspond to maintenance areas that are to be reviewed by the staff as well as specific guidance and acceptance criteria that applies to those areas. The staff plans to issue the proposed EPU amendment in the beginning of May 2008 provided ACRS writes a letter report that states that the Hope

Creek EPU should issued.

PSEG plans to implement the proposed 15% Hope Creek EPU in two steps. One, a proposed 11.5% increase will occur in the first operating cycle following Hope Creek EPU approval. Then two, the licensee will implement the remaining 3.5 percent proposed uprate during a subsequent operating cycle following the proposed amendment of the -- the approval of the amendment. You will hear more detail about this in a little while from PSEG.

Basically, PSEG's application followed the guidelines of a constant pressure power uprate of General Electric's topical report. After I conclude my remarks, PSEG will provide an overview on their licensing approach as well as their modifications required and their implementation schedule. Today, you will hear a great deal of more detail on fuel methods from the staff and PSEG in both open and closed sessions. PSEG applied for an EPU amendment by letter dated September 18th, 2006. There were 37 supplements. The majority of these dealt with the steam dryer. The staff spent a great deal of time reviewing the steam dryer information to make a finding of reasonable assurance. So like any good movie plot, we will save the most interesting steam dryer information until the second day.

The majority of tomorrow will consist of steam dryer discussions in both open and closed sessions. I would summarize the agenda as the following. The bulk of day one is devoted to fuel methods and the bulk of day two is devoted to steam dryer. As you can see from the agenda and the slides, the remainder of the time is devoted to operations training, human factors, power ascension and testing, containment analyses, flow-accelerated corrosion, probabilistic safety assessment, risk evaluation, materials and chemical engineering, electrical and grid reliability, INC and source terms and radiological consequences.

So this concludes my presentation as far as the introduction. I would like to turn it over to Mr. Thomas P. Joyce, PSEG Senior Vice President, Operations for Salem/Hope Creek. This is a position Mr. Joyce has held since June 2007. Mr. Joyce has more than 32 years of experience in commercial nuclear power operations. Prior to working at PSEG, Mr. Joyce was site vice president at Exelon's Braidwood Station. Mr. Joyce holds a bachelor of science degree in nuclear engineering from the University of Missouri and a master of business administration degree from

Keller Graduate School of Management. Here is Mr. Joyce.

MR. JOYCE: Good morning. My name is Tom Joyce. As John Lamb stated, I am PSEG's Nuclear Senior Vice President of Operations for both Salem and Hope Creek units. I am very pleased to come before the ACRS Subcommittee today and have my team, along with a number of industry experts, present information to support our application for the extended power uprate of the Hope Creek facility. I, along with the Hope Creek management team, have been actively engaged in advancing this important plant initiative.

I am confident that our robust effort has been reflected in the application and that the presentations today and tomorrow will confirm the NRC staff's conclusions in the safety evaluation. I also wanted to take this opportunity to extend my appreciation to the NRC's NRR staff's professionalism throughout this process. The NRC process was challenging and resulted in the desirable outcome of a strengthened product. The regulatory challenges ultimately serve to enhance our effort and further the mutual goal of meeting the standards of projection of the public.

With respect to my and the team's approach to this project, the focus is first and foremost on safety, both nuclear as well as industrial. Without this cornerstone, no other objectives can be satisfied. As you will hear over the next two days, this project has evaluated a comprehensive and exhaustive list of technical issues, all of which have been resolved or addressed with sufficient safety margins.

We will continue to evaluate information related to our power uprate and take conservative actions if necessary. As an example, you will hear bout our power ascension testing program which formalizes the safety philosophy by establishing a criteria for conservative actions based on plant conditions and data. This is the approach we take when running the plant and we take the regulatory safety obligation to the public and ourselves with the utmost seriousness. Simply put, it is the right thing to do.

With respect to your questions, it is my expectation that if the presenter does not know the answer during the individual topic discussion, we will get you a satisfactory answer before the close of the session.

Turning to the agenda, today we will be

covering an overview of the EPU project, power ascension and operations, fuels topics, containment analysis response, flow-accelerated corrosion and pressure and temperature limits. And tomorrow we will be covering steam dryer vessel internals PSA and grid reliability.

Principle presenters will be Paul Davidson who is the Engineering Director at Hope Creek, Bill Kopchick from the Operations Department, Don Notigan from our Fuels Department, Ed Burns from Air and Engineering and the PRA, and during the closed session for the dryer, Dr. Alan Bilanin from CDI will also be presenting some information.

So if there are no other questions or not questions for me, I would like to turn this over to Paul Davison to provide the overview of the uprate. Paul?

MR. DAVISON: Good morning. As Tom mentioned, my name is Paul Davison. I am the Hope Creek Site Engineering Director. I'm also the EPU Site Sponsor and also the Test Director for the EPU project. The overview of this session will talk about the extended power uprate and will cover the seven topics listed on the slide -- the design of the facility, the licensing strategy for our submittal, the impacted key plant parameters, facility modifications performed to support the power uprate as well as our remaining implementation actions.

Moving onto slide six, as mentioned previously, Hope Creek Generating Station is wholly owned and operated by PSEG Nuclear, LLC which is a subsidiary of PSEG Power. The station shares a common site with Salem Generating Station which is located adjacent to the Delaware River near Salem, New Jersey. The station is a General Electric BWR-4 design. We operate on an 18-month fuel cycle. Our next refuel outage commences in the spring of 2009. The station also utilizes a natural draft hyperbolic cooling tower for our normal condenser heat removal as well as the Delaware River itself as our ultimate heat sink.

The operating license, as mentioned previously, was issue in July of 1986 with commercial operation commencing December of that same year.

From a containment perspective, Hope Creek's primary containment structure is a General Electric Mark 1 which is denoted by the inverted lightbulb shape containment as well as a suppression pool heat sink which is a torus. The original licensed thermal power of LLTP was 3293 megawatts in 2001 through the Appendix K feedwater uncertainty uprate we implemented and took the unit to 3339 megawatts thermal by using the AMAG or advanced measurement in analysis group cross-flow system. That system uses externally mounted ultrasonic transducers on the common feedwater header to measure feedwater flow with greater certainty.

The requested extended power uprate will increase the licensed thermal power to 3840 megawatts thermal. This is 115% of our current licensed thermal power or 16.6% of our original licensed thermal power.

MEMBER BANERJEE: The AMAG system, will it be re-calibrated for this flow rate?

MR. DAVISON: We've done two things -- one in response to some industry experience. We've done a full calibration at 100% power now coming out of our refuel outage by using other ultrasonic devices on our individual three feedwater lines and also, we use our secondary systems. We use the venturis that were installed during original construction, of course, as well as balance-of-plant operating conditions, like turbine first stage pressure, to make sure we're always balanced and ensuring that we're never in an over powered condition.

There is no specific re-calibration that's required of the system when we go to power uprate.

However, during our power ascension testing, the same type of comparisons will be done to ensure that there has been no change by the increase, approximately 16% increase in feedwater flow and, of course, the temperature change that occurs with that.

MEMBER BANERJEE: So was it calibrated with a time-of-flight method originally or how was it calibrated, just against venturis?

MR. DAVISON: No. The ultrasonics themselves were statistically compared to three individual sets of ultrasonics that were installed on our individual feed lines. So general system description is three feedpumps, three feedwater trains that have individual lines where we put ultrasonic devices on, that goes into a common header, and that's where the actual AMAG's cross-flow system is installed. What we did was statistically compared the data over long periods of time from the individual flow elements which have greater accuracy, the straight runs that are unobstructed to ensure that you have the correct flow characteristics where the ultrasonics were placed, and then did that comparison, and we utilized the comparison to calibrate that.

The comparison to the venturis and the first-stage term pressure are secondary checks in response to industry OE where folks have had problems and have ended up over powering units.

MEMBER BANERJEE: So it's basically a consistency check?

MR. DAVISON: Correct.

MEMBER BANERJEE: And at the higher power you do that?

MR. DAVISON: Yes. The other thing that -- the Appendix K uncertainty is taken out of our re-rate power, so we will not actually be utilizing the cross-flow system for a reduced margin and greater certainty. What we will be using the cross-flow system for is to maximize the efficiency or accuracy of our flow venturis. But that 2% -- 1.4% margin is back into our licensing basis.

MEMBER BANERJEE: So the flow venturis, they haven't had any sort of roughening at the throats or anything like that?

MR. DAVISON: The operating experience of fouling and defouling events, we do see minor indications of that. In fact, one of the reasons why we went and did the full power calibration coming out of our last refuel outage was to check for them, periodically check for that, because you do see some buildup and sloughing off of the coating, the fine coating that occurs on the venturi itself. As far as damage or needing to replace due to erosion of our venturis, no, we have not seen that at the station.

MEMBER BANERJEE: Okay. Thanks.

MEMBER MAYNARD: Could you -- if you're going to do this later, that's fine, too, but the reason you chose 3840 rather than going to the 3952?

MR. DAVISON: Yes. Actually, I'll take you through this next chart just for a comparison and then there is some further information, but the business decision that was made back in the early 2000's, we initially set out to do a 120% uprate. That's what the plant was designed for. In fact, you'll hear about the significant margin in, like, our condensate and feedwater systems because of that. At the time, with unknown uncertainty with respect to the grid and moving forward and the cost associated with that, a business decision was made to go for a 15% power uprate.

So it was strictly a business decision at that time, because we needed to put in motion the changes, primarily through General Electric and the purchase of three low-pressure rotors and a high-pressure rotor to basically replace our entire turbine train. So at that time, we made the decision we're going to buy the equipment that'll support a 15% power uprate.

MEMBER MAYNARD: Okay.

MEMBER ARMIJO: So with this equipment on the turbine, you're going to be limited to 115?

MR. DAVISON: Well, actually, right now, as you'll hear, we're actually going to be limited to 111.5% this cycle. We will require even additional modifications, primarily focused on the high pressure turbine to change out the first four stages of diaphragms to be able to get to 115% power.

MEMBER ARMIJO: Okay. But that'll be the limit once you make those modifications?

MR. DAVISON: Correct.

MEMBER ARMIJO: Okay.

MR. DAVISON: Okay. ON the slide that you have in front of you, because of the discussion I just had, we started off -- and many of our initial analyses were based on 120% -- when we focused in at 115, we did the balance or the remainder of the analyses at 115%, and we were comparing Appendix K and pre-Appendix K power levels. We thought we'd just do a quick run through of a comparison of our OLTP, CLTP and EPU power levels. You can pull it out and reference it to our discussions later one.

Vince will just point out a couple of key items here where we initially set out as I mentioned, to do the standard 20% uprate. Therefore, a large amount of our EPU analysis was completed at that 120% or 3952. So that's the 3952 equating to 120%. Appendix K uprate brought us to the 100% current licensed thermal power of 3339. That's the center bar. Our requested EPU license change request for 15% power increases that or equates to 116.6 of our original licensed thermal power. So reading across the 3840 megawatts thermal line, you see that's 116.6% of our original license, a 15% increase on our current license, and that will be the 100% value when we reach EPU conditions.

During the cycle, we'll be limited to that 111.5% based on our main turbine, specifically the high-pressure turbine. And that's really maintaining our main turbine 3% control valve wide open transient response margin. That is why that turbine right now will be limited to 111.5. Mention the modifications that we'll need to do to be able to rate that unit -- that piece of equipment to 115%. And additionally, we are focusing on cooling tower enhancements during our peak summer atmosphere condition, mainly high temperature.

Our cooling tower will also start to limit our megawatt electric output. We'll actually, in some cases, have to reduce power by a few percent to ensure that we maintain the appropriate margin with respect to turbine back pressure. So again, the major limiting component for year-round operation is the high-pressure turbine. Summer months will be focusing on cooling tower efficiency improvements.

Okay. Next slide -- we have made numerous changes, both physical and licensing wise to get to where we are today with this proposal. The 10 CFR 50.59 process, of course, was utilized. Several licensing actions in support of our EPU implementation were also required. The adopted amendments have been previously NRC reviewed and approved, and we fully implemented them at Hope Creek. Those changes include the full scope of the alternate source term was approved for implementation in October of 2001. All EPU analysis was performed using the AST methodology. The reactor vessel pressure and temperature limit curves were revised in November of 2004, currently in place, and they have been updated to include the EPU neutron fluence levels.

General Electric methods for core design and transient analysis at the EPU conditions have been utilized since December of 2004. We're currently operating on our third cycle with fuel from two different vendors, General Electric and Westinghouse. The ARTS/MELLLA implementation was February of 2006. This expanded the operating domain to reach rate of power at lower core flow and also provides the necessary reactor recirculation flow control range for our ultimate EPU implementation.

The remaining open license amendment request is our current submittal for EPU. The application was submitted in September of 2006 and accepted for review by the staff in October of the same year. It utilizes the constant pressure of power uprate license topical report for the non-fuel-related topics in the extended power uprate topical report for the fuel-related topis due to our GE/Westinghouse fuel load.

Slide nine talks about the specific key parameters that are changing with EPU. In addition to the 501 megawatt thermal uprate required to change the recirc flow operating range, there was no change in the actual flow limit of 105 million pound mass per hour. The lower flow limit was increased from 76.6 to 94.8 million pound mass per hour since we did not expand the MELLLA operating domain. Steam dome pressure remains unchanged. The feed and steam flows increase typically what you would see with a 15% power increase. There is a minor delta between the feed and steam flow and the numbers there, and that's due to the constant CRD cooling water that's flowing into the vessel, water inventory about 60 galls a minute.

MEMBER BANERJEE: Let me ask you a question.

MR. DAVISON: Yes.

MEMBER BANERJEE: Since you're only going up to, let's say, 116% or something, do you still have some operating range which is going to be full control there in MELLLA --

MR. DAVISON: Yes, with MELLLA, that's correct.

MEMBER BANERJEE: So you'll have, what, some region which is still you're able to control the flow without control rods?

MR. DAVISON: Absolutely. The basic operation of the unit will remain the same as we are today. We'll be doing flow manipulations to change reactor power for minor and then control rod manipulations.

MEMBER BANERJEE: So perhaps at some point, you could show us some typical operating domain later one?

MR. DAVISON: Yes. In the fuels discussion, we can show the power-to-flow map and we can go through that. Okay?

All right. The final feedwater temperature increases by 9 degrees Fahrenheit primarily due to the higher main turbine extraction pressure of the feedwater heaters themselves. Other than the core thermal power increase of 15%, the impact of EPU to the power plant is primarily in the balance-of-plant steam delivery systems.

MEMBER ARMIJO: What will your core power density be at EPU, and how does that compare to other BWR-4s --

MR. DAVISON: Don?

MR. NOTIGAN: -- kilowatts per liter.

MR. DAVISON: Mr. Notigan, address that question, please?

MR. NOTIGAN: Yes. Don Notigan, PSEG Nuclear. We compared Hope Creek's power density to the experience base from the licensing topical report. Hope Creek will be below some of the maximum kilowatts per liter density, but it is within the experience range and fits right in with the curves. I'll be presenting some of that in my discussion.

MEMBER ARMIJO: Do you have a number?

MR. NOTIGAN: I believe it's less than 57 but I can look that up.

MEMBER ARMIJO: Okay.

MR. DAVISON: Okay. On slide ten, Vince? We talked about the licensing approach. This is the actual physical modifications that were required to be implemented at the station in support of EPU. In preparation for the EPU, we performed a rigorous assessment of reductions in both operating and design margins. Training, procedure changes, program changes, testing changes were all implemented to account for reductions in margin as a result of the 15% increase in addition to these modifications.

Some examples of the components and systems that were impacted by this strategy of uprate and assessment to manage the margin associated with them, main steam line piping vibration and steam dryer loading, no changes to the main steam system or the actual vessel steam dryer were required. We did do analysis to show that the margin exists. Obviously, we'll be talking about that in greater detail on tomorrow's session, but we'll also be implementing monitoring which will be part of our monitoring plan to ensure that there are no issues associated with our analytical assessment of the margin associated with things like main steam line piping and steam dryer.

High-pressure turbine -- talked about in addition to the actual physical change of the high pressure turbine and the requirement to limit power to 111.5%. We will monitor that and keep power to 111.5%. Again, that was to maintain a 3% valve wide open margin for transient response.

Condenser back pressure and condenser demin., condensate demin., inlet temperatures will also have some limitations really going back to the cooling tower operations. No specific change is made to the operating facility for that. However, we will be monitoring condenser back pressure as we do all the time, but specific focus in the summer months because of our cooling tower limitations and essentially being at the mercy of the environment. But there are specific guidelines set up with Operations that they have today even pre-EPU that in the event of a challenge to condenser back pressure before a transient would occur, they have the direction to reduce reactor power.

Steady state operations with the reactor feed pump -- we can essentially operate with one of our reactor feed pumps. Hope Creek is designed with three secondary condensate pumps, three primary condensate pumps and three reactor feed pumps. Right now we can operate with a feed pump out of service up to 100% power. Of course, with change of power to 115%, we will need to procedurally control the point with which we can operate the unit with a flexiplace or other primary or secondary condensate pump out of service.

And the steam bypass capability, we did require a license change coming out of this outage in light of our high-pressure turbine replacement, which reduced our main steam bypass, our bypass valve capability from 25 to 22%, again, controlled in our setpoints for our instrumentation as well as procedurally for how we operate the reactor.

But in addition to those, there were many changes that were actually physically done to the plant. And what I will do is I'll just walk through and cover the modifications that were done to the facility that we needed to do to either increase or maintain margin so that we can implement an EPU project.

Starting in 2003, we did implement two changes. The 500 kV breaker was added due to our independent system operations which is Pennsylvania, New Jersey, Maryland, PJM, interconnect analysis for the additional output that Hope Creek would have. The breaker was added to ensure all grid stability criteria were met. The new breaker was added to provide backup line fault clearing. This prevents tripping of Hope Creek and the interconnecting line between Salem and Hope Creek switch yards to preserve grid stability. And this will be reviewed in detail in tomorrow's session on grid stability.

Also, the cooling tower internals were upgraded to install new flow distribution piping, fill material and realignment of the water distribution. We're essentially making sure that the tower is operating at its maximum efficiency.

Moving to 2004 -- I mentioned that we replaced -- all three of our low-pressure rotors were upgraded. This also eliminated the torsional stress limitation by installing the GE monoblock design rotors. We also installed the digital EHC, or electro-hydraulic control system, and a turbine supervisory instrumentation system upgrade to improve control reliability as well as vibration monitoring capability of our main turbine train.

The main generator nameplate rating was increased due to the power uprate. In addition to the nameplate rating which was analytical, we did have to increase the standard water coolant system flows and also the iso-phase bus cooling associated with that to allow for the greater increase in power.

The two main turbine moister separators and the piping between the high-pressure and low-pressure, we have two large moisture separators. The internal chevrons or the moisture separator internals themselves were replaced and that provided additional efficiency as well as we gained approximately 6 megawatts electric by doing that. That's essentially increasing our steam quality to the low pressure rotors.

And then the alpha and bravo main power transformers were replaced to match the previously replaced Charlie phase transformer, three individual phases. That experienced default due to solar-magnetic disturbances back in 2001.

MEMBER BONACA: Excuse me. I have a question.

MR. DERRICK: Yes.

MEMBER BONACA: If you lose one feedwater pump now, before the change, you stay at 100% power?

MR. DAVISON: No. The -- in response to a loss of a feed pump, we will incur a intermediate runback on our recirc pump, so it will actually reduce power automatically in response to the loss of a feed pump.

MEMBER BONACA: With the low -- with the power change after the occurrence?

MR. DAVISON: That occurs right now. Is that correct, Bill?

MEMBER BONACA: Oh, now.

MR. KOPCHICK: That's right.

MR. DAVISON: Yes. The system's designed with based on the rating of flow, loss of a pump -- it's an anticipatory runback to prevent degradation to level and a reactor transient scram.

MEMBER BONACA: What level?

MR. DAVISON: I'm sorry?

MEMBER BONACA: To what power level?

MR. DAVISON: The intermediate runback, a recirc takes us back to approximately 80% power.

MEMBER BONACA: And now with the new -- after the power uprate, you're just simply readjusting the runback down to a lower value?

MR. DAVISON: The specific value for the runback stays the same, correct?

MR. KOPCHICK: Hi. My name is Bill Kopchick. I'm the District Operations Superintendent in the Operations Department. The runback on a trip of a reactor feed pump is initiated with a reactor feed pump concurrent with receipt of a Reactor Level 4 which is 30 inches. The plant response is to reduce reactor recirc pump speed to 45%. At current licensed thermal power, that will reduce me to approximately 80% current licensed thermal power. It will be somewhat higher than that under EPU conditions.

MEMBER BONACA: Thank you.

MR. KOPCHICK: You're welcome.

MR. DAVISON: Okay. And the last modification for 2004 were the addition of flow-induced vibration analysis via accelerometers installation on many of our piping systems. The accelerometers allowed us to collect the baseline data to verify that we had no flow-induced vibration problems. Critical piping is instrumented, and as you'll hear in our discussion of power ascension testing, we have Level 1 and Level 2 acceptance criteria that we will be closely monitoring the piping for vibration for power ascension. In addition, numerous other balance-of-plant piping were qualitatively walked down and will be walked down as part of our power ascension testing program as well.

MEMBER ARMIJO: Has that equipment been

removed? You say temporary. Is that -- was just in for a short while or?

MR. DAVISON: No. It will remain installed through the -- it's been installed and will remain installed through the entire power ascension testing program. So it remains installed today and we periodically take readings just to verify that we have not, you know, have any failed sensors or damaged cables.

In 2006, so in that column, the ARTS/MELLLA I mentioned previously was introduced. The alpha steam jet air ejector heat exchanger was converted from a parallel flow to a cross flow design. That was already previously implemented on the BRAVO steam jet air ejector, and that's really around improving efficiency for summer operations of our off gas air removal system. The main generator iso-phase bus cooling system was upgraded to increase the air flow as well as the heat exchanger of cooling water flow, which is a cooling medium for that heat exchanger.

The number 2 and 3 point feedwater heat dump valves were replaced. That's to increase their capacity to respond to transients, and numerous setpoint changes have been made -- six safety relief valves on the two main turbine moisture separators and three relief valves on the number 5 point feedwater feedwater heaters were all increased due to the normal operating pressures increase expected as part of the EPU implementation.

We did modify six existing pipe supports on the main steam lines in our turbine building. And that was due to increased loading of the higher steam flow when we have a turbine stopped off transient. So we just -- the actual -- no additional lines were installed. We just modified them to strengthen them. And then strain gauges -- additional accelerometers and thermal couples were added to the main steam lines, RHR piping, recirc piping to assess the acoustic characteristics of the associated piping systems. And again, that data is necessary for the steam dryer analysis which we'll be covering on Friday.

Finally, in 2007, the condensate demineralizer resin traps were upgraded with new strainer elements, and that's to account for the increased differential pressure across these traps resulting in the increased flow we will have during EPU conditions. The high-pressure rotor was finally replaced, as I mentioned, in our last outage. The nozzles, diaphragms and packing were replaced to support the increased steam flow of the rerate. Again, additional modifications will be necessary to take us all the way up to the full 115%.

Additional drywell main steam line strain gauges were installed, really in response to industry operating experience that other plants incurred failures which limited or reduced the accuracy of their data on the strain gauges, so we went and installed eight strain gauges per location. That allows redundancy so that we do have some type of strain gauge failure, we will still have adequate data coming to us for analysis when we do the uprate.

Small-bore piping changes associated with the main steam lines really between the pressure averaging manifold and the turbine stop valves themselves were upgraded by adding two-over-one taper fillet welds, and that's just to minimize fatigue-induced cracking on EPRI guidelines and some OE that was out there. Numerous BOP instruments were rescaled and setpoints were adjusted in support of the EPU.

And then finally, the reactor recirc pump runback logic was changed for the trip of a primary condensate pump. We used to have a full runback associated with the trip of that pump. WE changed that to an intermediate run to take advantage of the design capacity, extra capacity of our condensate and feedwater system. It really is focused on minimizing the transient to operations during a trip of the pump.

And the RCIC turbine exhaust high-pressure trip setpoint was adjusted to 50 pounds to maintain RCIC availability and that's associated with our 4-hour coping period following a station blackout event in accordance with SIL-371.

CHAIR ABDEL-KHALIK: Is 50 psi the correct number?

MR. DAVISON: Yes. And then, finally, moving it forward into 2008, the online implementation listed setpoints -- that's the main steam line hot flow setpoints -- OPRM setpoints, APRM setpoints, and hydrogen water chemistry flow adjustments control bands will be changed subsequent to issuance of our license change. So we're awaiting for that to do online once we move forward.

In summary, all the changes required to support EPU have been implemented with the exception of the license change restraint setpoints.

Moving on to slide 12 for the implementation itself. So with all the physical modifications actually completed, the remaining tech spec-driven setpoints that I mentioned before will be implemented online in this operating cycle, the power ascension in accordance with our test plan from 100 to 111.5% will then commence. The goal is to implement prior to our independent system operation PJM grid summer peak period which essentially begins June 1st of this year.

That concludes my presentation pending questions.

MEMBER MAYNARD: I'm still just a little bit confused on your feed pump-condensate pump capabilities. I thought earlier in the discussion you said that you could operate with two of them?

MR. DAVISON: Correct.

MEMBER MAYNARD: Maybe I assumed that what you were saying is you basically had three 50% pumps, but you're talking about having runbacks any time you lose one. Is that just -- you mentioned precautionary. Could you actually operate at 100% power with just two pumps?

MR. DAVISON: Yes. For clarification, steady state operations, if we were to remove a pump from service, coming out of an outage, have a maintenance problem or have a pump that we need to take out of service in a controlled fashion, operations would reduce reactor power, take the pump out of service, increase reactor power back up. So in steady state operations, no issues. The runback is required because you have a transient associated with the instantaneous loss of a pump, condensate or feed pump, immediate level effects, so you have the runback to protect from the low level scram.

MEMBER MAYNARD: Okay. That's fine. That answers my question.

MR. DAVISON: Thank you.

CHAIR ABDEL-KHALIK: If there are no further questions, we'll proceed with presentation.

MR. DAVISON: Thank you. I would like to now Bill Kopchick. He's our Shift Operations Superintendent for the Operations portion.

MR. KOPCHICK: Good morning. As Paul Mentioned, I'm Bill Kopchick. I am the Shift Operations Superintendent at Hope Creek. That means for the operating shift personnel, senior reactor operator, reactor operators and equipment operators, they will ultimately report up through me. My boss is the Operations Director who would be Paul's peer in our management team. I've been licensed at Hope Creek for 10 years. Prior to Hope Creek, I was a shift technical advisor at the Oyster Creek Station. And during power ascension, I'll fill a role as a Test Manager as we perform our power ascension testing upon approval of our license submittal.

My role in the development of the project over time has been to make sure there has been either a senior reactor operator or a reactor operator engaged with the project. Any questions that were operationally related would then come back to me for approval or operations shift input, so we made sure that operations personnel were aligned with the project and were able to implement it on shift.

To my right is Paul Lindsay. I'd like to afford Paul the opportunity to introduce himself.

MR. LINDSAY: Good morning. Again, as Bill said, my name is Paul Lindsay. I work for Mainline Engineering Associates. I am a former licensed SRO at Hope Creek Station, also a former mechanical design supervisor for Hope Creek and Salem units. My role in the project has been primarily mechanical design support. However, I was responsible for the development of the test program as well as the implementing test procedures.

MR. KOPCHICK: Thanks, Paul. The intent of this portion of the presentation is to cover three operationally-focused topical areas associated with the implementation of extended power uprate. These will be operator training and the efforts we have taken to ensure operator readiness for EPU implementation and subsequent high-power operation. Second is the impact of EPU on operator response to transients and postulated events including the operator actions, mitigating strategies and response times. And lastly, I will outline our power ascension testing program which has been designed to successfully implement a safe and systematic plant power ascension to extended power uprate power levels.

First in the area of operator training, as Mr. Davis had mentioned, we have incorporated numerous station modifications to prepare us for power uprate. Some of these included new main power transformers, high pressure and low pressure turbine replacements, enhanced monitoring systems, and multiple instrument replacements to include scaling and setpoint changes. The majority of these modifications, as Paul stated, particularly involving those that involve physical changes, have been in place for one or more operating cycles. For each of these, specific system training was included in both non-licensed operator and licensed operator requalification programs and thus, the operators, including myself, are currently familiar with the changes made, the operating limitations required, and the characteristics of the new equipment that has been installed.

In addition to the system training on these previously mentioned modifications, we have conducted EPU power ascension training, steady state training, and transient training in both the classroom and on the Hope Creek simulator for all operating shifts. Regarding procedure changes, while EPU implementation involves numerous procedure changes to the station, the changes to the procedures associated with the aforementioned system modifications represent the majority. These changes have been trained on. They are in place. Operators are currently familiar with the precautions and limitations and operating requirements associated with this equipment.

The balance of outstanding changes associated with EPU implementation will involve changes to tech-spec instrumentation setpoints which obviously cannot proceed until a license change request is approved.

CHAIR ABDEL-KHALIK: Now the 11.5% change is going to be a mid-cycle change for this current cycle. Has the simulator model in existence been uprated to 11.5% and that's what the operators have been training on?

MR. KOPCHICK: Yes. What we did for the simulator modeling is we've obviously done a pretty extensive amount of analysis on plant performance at EPU conditions up to 115% and in some cases, as Paul mentioned, 120%. In an effort to ensure simulator response would be as we would expect under EPU conditions, we did run a battery of transients on the simulator to include balance-of-plant system response to ensure that the ANSI standard required margins for performance of the simulator were met. That was performed prior to the training being initiated.

A second facet associated with the simulator that is probably pretty important is we implemented a new balance-of-plant thermal hydraulic model called THOR which is an advanced model that we use to back up the analytical calculations that were performed for balance-of-plant response. So the simulator has been validated to respond as we expect the plant to respond in EPU.

I would add that the documentation that our station requires -- it's a corporate procedure to formally document that testing per the ANSI standard -- is still in progress with an expected completion date of April 13th and final reviews completed by

April 27th.

MR. DAVISON: Paul Davison. For clarity, the simulator has two modes of operation, one for training at the current licensed thermal power and when they're doing EPU testing at the EPU rated so they can actually run the plant as it would look and appear to them at the uprated power. Is that correct, Bill?

MR. KOPCHICK: That is correct. It is really a function of setting up the initial power.

CHAIR ABDEL-KHALIK: Thank you.

MR. KOPCHICK: Getting back to procedure changes, the balance of our outstanding changes are associated with tech spec instrumentation changes. Those procedures are complete and awaiting approval of the license change request. Some changes --

MEMBER BONACA: Just to understand it better, you're going to go to 111% power and then later on another step up to 115% power?

MR. KOPCHICK: Correct.

MEMBER BONACA: What does it do to your tech specs and to your protection system? I mean are you setting it up for 111% power now and then later on adjust it 115%, or do you have a different strategy?

MR. KOPCHICK: The tech spec setpoints are based on 115% power uprate. The limitation of 111.5% current licensed thermal power is turbine related, so from an operator perspective, that presents some small challenge, because we will be operating at 97% power. We will set up our procedure network. Obviously, being an operator, we operate in accordance with procedures to set limitations procedurally to keep us at 111.5.

MEMBER BONACA: Which is 97%?

MR. KOPCHICK: Ninety-seven percent. That is correct.

MEMBER BONACA: Okay. So could you just elaborate a little bit? How do you train the operator to see that? I mean your setpoints are set at 115% power.

MR. KOPCHICK: Right. Okay. The way, as an operator, I would control reactor power output is I would use a heat balance that's updated every second off of a plant process computer. The plant process computer will give me a number in megawatts thermal. Right now the way my license is set up, I'm limited to 3339 megawatts thermal. We use a 5-minute average to control that power level. If I see the 5-minute average approach or exceed that number, I will reduce reactor recirc flow to maintain the 5-minute average below the limit. That's how we intend to set that up for the operator control, to minimize a number of other parameters that have to monitor.

MEMBER BONACA: Okay. My concern was how much do you have to change later on, but what you're telling me, it's pretty much you're implementing 115% power really --

MR. KOPCHICK: Right.

MEMBER BONACA: -- from your setpoints and then you're controlling at another power level?

MR. KOPCHICK: That's correct. Our procedure network sets the control band for the operator as it would with any other system including the reactor.

MEMBER ARMIJO: I just want to get a clarification. You're currently in Cycle 14, is that correct or?

MR. KOPCHICK: I think that's -- Don?

MR. NOTIGAN: This is Don Notigan, PSEG Nuclear. Currently, we are in Cycle 15 at Hope Creek.

MEMBER ARMIJO: You're currently in 15 and you're going to go to 111% during this cycle?

MR. NOTIGAN: That is correct, in Cycle 15.

MEMBER ARMIJO: And then in Cycle 16,

you'll go to the remaining up to 115?

MR. NOTIGAN: We have information in another presentation that describes an implementation plans for going up to the next power level. I don't believe we're making a commitment for the next cycle.

MR. KOPCHICK: Okay? Okay, so regarding procedures, some changes have been made to our emergency operating procedures which I will cover in our next slide. However, there are no new abnormal operating procedures required for EPU implementation. We did not require any new emergency operating procedures as a result of EPU, but I will cover the changes to the existing procedure network that we accomplished.

Regarding operating experience, industry operating experience associated with power uprates was incorporated into our operator training. Hope Creek reactor operators and senior reactor operators that were involved with the test program development with Paul Lindsay visited several sites that have implemented extended power uprates and have utilized this experience and additional OE in training development. This experience has been incorporated under both the power ascension test program and the implementing procedure to accomplish the power ascension test which I will discuss in more detail later. In addition, specific Hope Creek operating experience and industry EPU experience has been incorporated into individual system monitoring plans on a system-by-system basis that will be used by both operators and engineers implementing the power ascension procedure.

In summary, operations personnel have trained on and in many cases have been operating equipment necessary to implement EPU at our station. Such training has included power ascension testing, steady state operation and transient response training in the simulator to include lessons learned from other facilities. In conjunction with planned just-in-time training which we will perform prior to EPU power ascension, these activities will ensure an informed but cautious and questioning approach to the new EPU power level.

The purpose of this slide is to discuss the impact on operations with regards to response to transients or assumed or postulated accident conditions under EPU operating conditions. Hope Creek has 123 post initiating event operator actions credited in its plant risk program. There are no new operator actions or tasks associated with implementing

EPU at our station. Due to higher decay heat load, there is a small impact on the time available to detect, diagnose, and perform actions associated with transients or accident conditions. However, the impact does not adversely affect plant operators.

MR. WALLIS: This is because the times are already quite low, isn't it?

MR. KOPCHICK: That is true. The increased decay heat load is the basis for the reduction in response times. I have several examples I'll cover now to go over really what the changes look like to me as the operator. Some examples of these impacts are time to achieve cold shutdown following a design basis ascent. This changes from 9 hours to 13 hours.

MR. WALLIS: There's oodles of time to figure it out, though?

MR. KOPCHICK: There is. Tech specs in the case of achieving cold shutdown would require 24 hours to achieve cold shutdown, so we'll change from -- it'll take me 13 hours instead of 9 due to higher decay heat load. The time for RPV water level to reach the top of active fuel during a loss of coolant event is expected or predicted to occur about 20% faster due to higher decay heat load and a greater impact of wood collapse. And time to boil during shutdown conditions, which is managed by our shutdown outage risk management program, will shorten by less than or equal to 15% under all conditions.

MR. WALLIS: What happens during ATWS? Is there a shorter time to figure things out during ATWS?

MR. KOPCHICK: During ATWS conditions -- that is a good question -- we were audited by the staff under the most extreme ATWS conditions. We ran four scenarios under the audit conditions -- EPU condition, MSIV closure ATWS, current license thermal power condition with an MSIV closure in ATWS, and then an ATWS following a turbine trip under both EPU and current licensed thermal power conditions. What we're looking at as far as changes to the operator, from my perspective, is the actions or the way that we combat an ATWS will not change.

We may be slightly different than other facilities in that our process is if I have an ATWS condition and reactor power remains over 4%, I will immediate initiate standby liquid control. It was my proceduralized process before and it will be post-EPU. We also have an automatic standby liquid control initiation function redundant reactivity control system where if the operator doesn't take action, standby liquid control is initiated 3.9 minutes after the event. And we also have automatic feedwater runbacks on a high-pressure condition that will reduce RPV water level which is another stability mitigation strategy that's used throughout the industry.

So the difference for me as an operator under ATWS will not change. Obviously, it is dependent upon what power level the ATWS -- post-ATWS what power level I'm at, but my strategy is not going to change.

CHAIR ABDEL-KHALIK: No manual actions are required by the operators to reduce water level during an ATWS?

MR. KOPCHICK: Procedurally, we do, in our EOP network, purposely reduce RPV water level.

CHAIR ABDEL-KHALIK: Right. And therefore, the time required for the operator to take that manual action would likely be reduced under EPU conditions? That was really the heart of the question.

MR. KOPCHICK: I would have to take that question for lookup to see if the time actually changed, but as far as how I implement the actual operator actions to combat an ATWS, I'm well within any time that would change. And it's all really dependent upon post-ATWS power level.

CHAIR ABDEL-KHALIK: So procedurally, there is no time specified for the operator to reduce level manually --

MR. KOPCHICK: That's correct.

CHAIR ABDEL-KHALIK: -- during an ATWS.

MR. WALLIS: But it is pretty quick. I mean he has to do it pretty quickly now.

MR. KOPCHICK: We do. The first thing we would do is inhibit ADS. We'd initiate standby liquid control would prevent injection from other systems that may inject on lowering level, and then we would purposely reduce RPV water level below the feedwater sparger input level to provide additional heating of the water going in to further suppress power. I would say that occurs within the first 5 minutes of an ATWS event routinely during our training scenarios. But as far as the time goes, I would have to go and take an additional look at our case runs.

CHAIR ABDEL-KHALIK: If you can find that information, that would be helpful.

MR. KOPCHICK: Yes. Paul, if you could make sure we have that written down?

MR. DUKE: Yes. This is Paul Duke, PSEG Licensing. We have simulator scenarios that we ran with no operator actions, and we can share those with you later today.

MR. KOPCHICK: Thanks. So I did cover the impacts on some time durations associated with the higher decay heat load under EPU conditions. Overall, from a licensed operator perspective, the changes don't represent a significant impact to our ability to operate the facility. Specific changes to the probablistic safety assessment and the top 20 post-initiating operator actions will be addressed in more detail later in the presentation. Although there are minor changes to operator response times in the aforementioned events, there are no changes to the mitigation strategies associated with these or other design basis events that are required due to EPU.

As I mentioned, there are some changes to our emergency operating procedures due to the effects of EPU post-accident or post-event decay heat loads. These changes are limited to changes in some of the curves we use in our emergency operating procedures. And these would include the heat capacity temperature limit, pressure suppression pressure and boron injection initiation temperature curves which I'll present in the following slides.

The first slide shows the heat capacity

temperature limit. This is used when implementing the emergency operator procedures. During challenges to the primary containment, it's required for plant operators to maintain plant parameters beneath the heat capacity temperature limit curve. This ensures that suppression pull temperature is low enough to completely absorb the energy required to safely depressurize the RPV. As can be seen from the slide, the high pressure endpoint of the temperature of the curve is decreased by approximately 10 degrees Fahrenheit. The lower heat capacity temperature limit curve is due to the effects of higher decay heat load associated with the operation at higher EPU thermal power.

As far as impact on the operator would go, the requirements in the emergency operating procedures under any challenge to the containment is to monitor plan parameters associated with this curve and reduce reactor pressure as required to maintain beneath the curve.

CHAIR ABDEL-KHALIK: Now why the slight shift to the right at low pressure? What's the rationale for --

MR. KOPCHICK: At low pressure? We did two changes really. When we modified our EOPs which are currently in place, we included both the impact from EPU, and these are the curves at low pressure. On the left, you see the shift to the right. We also implemented the new BWR owner's group emergency protection guideline revision which is Revision 2. The calculational methodology changed which is the reason for the slight shift to the right at low pressure.

CHAIR ABDEL-KHALIK: Now what is the normal water inventory in the suppression pool gallon wise?

MR. KOPCHICK: Usually about -- from the operator's perspective, we measure it by inches -

CHAIR ABDEL-KHALIK: -- four pounds or something that we can check the adequacy of this calculation? If you can get it to us later on today. Thank you.

MR. KOPCHICK: I understand -- a volume of the suppression chamber.

CHAIR ABDEL-KHALIK: The volume of water in the suppression chamber.

MR. KOPCHICK: Volume of water in the suppression chamber. Okay? Any other questions on heat capacity temperature limit? Next slide, please?

Second curve illustrates the pressure

suppression pressure limit curve. During operation controlled by emergency operating procedures, plant parameters must be kept within pressure suppression curve or emergency reactor pressure vessel depressurization is required. As shown by the slide, the curve generally decreases by approximately two pounds, again, due to the affect of the higher decay heat associated with operating at elevated EPU.

CHAIR ABDEL-KHALIK: The units on the horizontal access can't be feet.

MR. WALLIS: Yes, they don't make sense. It must be inches. Can't be feet.

MR. KOPCHICK: Yes, sir. That is --

MR. WALLIS: It's a very strange design if it's feet. It's a very strange design if it's feet.

MR. KOPCHICK: You're correct. It is in inches and the span would be highest on the right, the highest level indicated in the suppression pool level that we can see by installed instrumentation and to the left would be the commencement of uncover of the vent pipe downcomers.

MR. WALLIS: This is water level above the bottom of the floors?

MR. KOPCHICK: It's actually from the instrument zero which is approximately three feet above the bottom of the --

MR. WALLIS: Three feet above the bottom. Okay.

CHAIR ABDEL-KHALIK: Now what actions is the operator required to take if this limit is exceeded.

MR. KOPCHICK: If I exceed, it would be emergency reactor pressure vessel depressurization opening up 5 safety relief valves to depressurize. The limitation imposed is ensuring that in emergency depressurization would -- the energy from the depressurization would be able to be absorbed by the suppression chamber.

As shown in this curve of the boron injection initiation temperature, the calculated boron injection initiation temperature decreased by between 12 degrees and 20 degrees Fahrenheit due to higher EPU core thermal power. At Hope Creek, during an ATWS in which reactor power remains above 4%, standby liquid control is conservatively injected before suppression pool temperature reaches 110 degrees. This operating strategy, as I mentioned earlier, will remain the same after EPU.

However, if the reactor is an ATWS situation with a reactor power less than 4%, standby liquid control must now be injected before the suppression pool temperature reaches a conservative 140 degrees, previously 150 degrees was a result of the curve. And again, this result is due to higher EPU power.

So in summary, regarding the impact of EPU on plant operators, the changes in operator responses to transients or accidents under EPU conditions is small. Procedure changes are limited to slight changes in curves associated with limits already contained in our emergency operating procedures. Thus, by maintaining similar strategies and mitigation approaches, the impact on operator proficiency and training needs is minimized.

MEMBER MAYNARD: I'm just a little bit confused on this curve and what you said. You talked about a 4% power. If it's above 4% power, they're required to initiate. Trying to relate that to this curve.

MR. KOPCHICK: Okay. Looking at the curve, 4% power is a highly observable indication for operators. It's my APRM downscale limit, so when I do achieve APRMs downscale, I will get 8 lights showing where reactor power is. If I don't have the APRM downscale, I don't have the 8 lights. It's under an

ATWS condition which is obviously a rather busy response for the operators. These are very highly observable from a human performance perspective. So procedurally, what we have keyed at the 4% observable limit on APRM power, if I do not have the downscales, the operators are trained and my procedures are set up to immediately inject standby liquid control.

If I am below 4% power, I have the downscales, then I watch suppression pool temperature. So really, the curve doesn't line it up for operator execution or implementation, but that is what we're watching.

So what changed is currently, at 4% power or below, I watch for and must inject standby liquid control before suppression pool temperature reaches 150 degrees. Post-EPU, my 4% power will be a higher power and the calculation we use for EOP curve development will require us to inject at 140 degrees by 750.

MR. LINDSAY: Just one item to add. This curve does not actually show up in the EOPs whereas the two previous curves actually show up. This shows the change --

MEMBER MAYNARD: It sounds to me like the operators don't really use this curve. They've got --

MR. LINDSAY: That's correct.

MEMBER MAYNARD: -- pretty straightforward power --

MR. LINDSAY: The guidance is for above --

MEMBER MAYNARD: -- temperature. That's what you do, so --

MR. LINDSAY: Correct.

MEMBER MAYNARD: So this curve just show that those actions ensure that you stay below -- stay within your curve there?

MR. KOPCHICK: Yes, sir. That is correct.

MEMBER MAYNARD: Okay.

MR. WALLIS: Now the number on the curve looks like 160 --

MR. KOPCHICK: Correct.

MR. WALLIS: -- it's just your number doesn't sound quite -- it's not important really, but the number you spoke about is not quite the same as the number on the curve. That's --

MEMBER MAYNARD: That's what I understand --

MR. WALLIS: That may kind of confusing.

MEMBER MAYNARD: -- is say if they're using numbers that are below, they're not going off this graph.

MR. WALLIS: That's correct.

MR. KOPCHICK: So for the new curve, you could say, I guess, 144 degrees --

MR. WALLIS: Yes, something like that.

MR. KOPCHICK: -- we inject standby liquid control at 140. And currently, we inject at 150. The curve would show 160. So in both cases, the selection criteria is conservative.

MR. DAVISON: This is Paul Davison. I have the answer to the follow-up question if you'd like that now?

CHAIR ABDEL-KHALIK: Yes.

MR. DAVISON: The tech spec minimum suppression pool is level or volume is 118,000 cubic feet. Tech spec maximum is 122,000 cubic feet.

CHAIR ABDEL-KHALIK: Thank you.

MR. DAVISON: You're welcome.

MR. WALLIS: That is independent of its temperature? This cubic feet always bothers me because it's not a measure of mass. It's a volume which changes if the temperature changes. You actually do control volume, do you?

MR. DUKE: This is Paul Duke. We also have controls on suppression pool temperature. We have limits for continued operational and suppression pool temperature.

MR. KOPCHICK: Tech spec limitations on suppression pool temperature, I think, is what you're referring to, Paul.

MR. WALLIS: It just seems strange. I guess it's because cubic feet is what you measure by means of the height.

MR. KOPCHICK: Is that what you --

MR. LINDSAY: Correct.

CHAIR ABDEL-KHALIK: are there any additional questions for Mr. Kopchick?

MR. KOPCHICK: Next slide, please? Next I'll present an overview of Hope Creek's power ascension test program to include a discussion of our preparation efforts, an overview of our test organization and test conduct and a discussion of how an incremental approach method will be used to achieve final power levels and a brief discussion of the tests themselves.

Preparation of EPU testing program began approximately one year ago. The plan was built utilizing the Vermont Yankee EPU approach to power ascension and similar methodology and acceptance criteria from the original Hope Creek startup test program.

The test plan aims to accomplish the following three objectives -- perform sufficient testing to demonstrate satisfactory equipment performance at the EPU power level, define a careful monitored approach to EPU power and meet all established commitments and regulatory criteria associated with testing. Preparation efforts also include a formation of a test team which I'll present in the next slide, development of key personnel roles and responsibilities such as the test director and test manager, and benchmarking including several trips to Vermont Yankee and Browns Ferry.

Based on these efforts, a test plan and an implementing test procedure was developed to accomplish these objectives. The procedure has been reviewed by the station's plant operations review committee on two occasions, subjected to several collegial reviews and two external reviews from individuals experience with other EPU testing programs. Based on the results of these reviews, we've concluded that our test program is in line with industry expectations for an EPU power ascension test program.

Regarding training, as discussed earlier, operators have been trained in both the classroom and on the simulator on the power ascension test procedure, are familiar with its contents, acceptance criteria and expectations. In addition, alla activities associated with this testing are considered infrequently performed activities which require the highest level of management involvement in accordance with our station procedures governing such activities.

Thus, based on the familiarity of operations with modifications already made, the training performed and other preparation activities including the conduct of periodic testing meetings, benchmarking efforts and department readiness reviews which will be implemented prior to implementation, Operations believes Hope Creek is well-prepared to execute a successful test program.

Next slide. As shown from this slide, the test organization will report directly to the Hope Creek Generating Station Plant Manager. The Test Director will work closely with the Plant Manger to allocate resources and establish both the administrative and technical procedures to support the plan. The test team is led by the Test Manager, a senior member of the Operations Department of which I will be one, whose function is management oversight. Similar to the On-Duty Shift Manager, this individual also has the authority to stop the test at any time. So either myself or the individuals who work directly for me, the shift managers, have the command and control authority to stop testing.

The balance of the organization is selected from individual plant departments such as Plant Engineering, Radiation Protection or Chemistry based on their area of expertise. These individual work closely on the development of the test plan and implementing procedure, and they've been involved in numerous testing preparation meetings are well-prepared to support EPU power ascension testing.

MR. WALLIS: It looks a long way down from the top to the bottom here.

MR. KOPCHICK: We can --

MR. WALLIS: I guess it's necessary but --

MR. KOPCHICK: It is.

MR. WALLIS: -- that why you don't have a leaner organization.

MR. KOPCHICK: I don't know that I can comment on that, but really, there's reasons for the different layers of challenges that we would expect to have in executing our plan.

MR. WALLIS: Long as the test director knows what's going on.

MR. KOPCHICK: Mr. Davison will be one of our test directors and he, as well as I, are accountable to know --

MR. DAVISON: We will have our --

MR. KOPCHICK: -- what's going on.

MR. DAVISON: -- outage control center staffed for the entire power ascension so that Ops can focus on uprate. Paul Davison. We will have our outage control center staffed through the entire power evolution, increase evolution, and the Operations folks can then focus on operating the plant, and the rest of the test team will be focused on the data collection and analysis and verification that --

MR. WALLIS: So if the GE startup consultant notices something, he can get to you pretty quickly?

MR. DAVISON: Absolutely. We'll all be in the same room.

MR. WALLIS: All be in the same room. Okay.

MR. DAVISON: That's correct.

MEMBER ARMIJO: You mentioned that -- at least I heard -- that there would be more than one test director? Is that correct?

MR. KOPCHICK: Paul?

MR. DAVISON: Yes. We'll have people responsible both on night and day shifts. So myself will be the primary test director help organizing what Bill said as far as making sure we have an organization established. However, to man it around the clock, we will have somebody else performing that function.

MEMBER MAYNARD: Could you talk just a little bit about the communications interaction between the control room staff and the test team? You know, who will the shift manager talk to or be communicating with?

MR. KOPCHICK: If you take a look at the slide -- I'm looking at my slide in front of me here -- the shift manager will report to the IPA test manager. It's required by our station procedures for infrequently performed activity that the test manager is organizationally senior to the shift manager. In this case, they work for me. They are my direct reports. The night shift test manager will be another operations superintendent who was a previous shift manager. At all times, for any testing we do, the on-duty shift has the command and control function. They control the unit. If there are any upsets outside of the testing, they will stop testing and respond to the transient. So the command and control structure really lies between the IPA test manager and the EPU implementation and test team leader.

So I would expect the test team leader to brief the control room crew on this is the test that we are doing at this. Training will have already been conducted. The operators are already familiar with the tests we're going to do. And then the shift manager will oversee the conduct of the test from a higher level with management oversight by the IPA test manager. If there are any problems, if there are any delays or we need to proceed on to the next test, my job as a test manager would then be to talk to Paul who would be a test director. He will have technical resources available to him, and Paul will be informing the plant manager on status.

I'll go over some more detail in some other slides as far as how the specifics of our power plateaus and power ascension will occur and where we intend to hold if that will be acceptable.

MEMBER MAYNARD: The shift manager still has responsibility for the plant. If he's uncomfortable with something, he can stop it?

MR. KOPCHICK: Yes, sir, at all times.

MR. WALLIS: This is who?

MR. KOPCHICK: The shift manager. He is, in fact, the senior license --

MR. WALLIS: Responsible --

MR. KOPCHICK: Correct.

CHAIR ABDEL-KHALIK: Will there be a stand-alone computer on which this data are going to be collected?

MR. KOPCHICK: Will be a stand-alone?

CHAIR ABDEL-KHALIK: As far as this.

MR. KOPCHICK: Operationally, we have a system called a control room integrated display system --

CHAIR ABDEL-KHALIK: Okay.

MR. KOPCHICK: -- which then feeds data to a land network on a system we call Plant Historian accessible by multiple engineers. We have automated the data acquisition function of our specific system performance plans to automatic data capture that information. It's also available in trend format.

MR. DAVISON: This is Paul Davison. One thing to add -- as I mentioned in the modifications, when we did the temporary modifications to add accelerometers and strain gauges, that is stand-alone equipment that's inside the facility, in the plant that we will collect data on and bring it electronically to the outage control center where the analysis will be done to it. So that's a stand-alone system because it's temporarily installed to collect the accelerometer and strain gauge data.

CHAIR ABDEL-KHALIK: Right. My concern is that -- I'm glad to hear that -- I'm not sure if you're aware of the recent trip at Hatch which was caused by a problem where you're collecting data presumably from a stand-alone computer that caused the plant trip because there was no adequate firewall between that stand-alone computer and the plant computer. And I just want to make sure that this is not a problem that you have not thought of.

MR. LINDSAY: The primary means of gathering data for the test, for the actual test where we're perturbating the plant, we're going to be using what we call our GTARS system which was the original GE transient acquisition system. That has no feedback or ability to cause any kind of control functions in the plant. And again, as Bill said, we'll be gathering data primarily off of our CRID systems which, again, have no ability to provide any kind of control feedback to the facility.

CHAIR ABDEL-KHALIK: Okay. So there are adequate firewalls between whatever system you're using to collect your data and the plant computers --

MR. LINDSAY: Yes.

MR. KOPCHICK: As our plan is written, yes.

CHAIR ABDEL-KHALIK: Thank you.

MR. WALLIS: What do you expect the role of the NRC inspector to be in this? What is the staff expect the role of the NRC inspector to be during this process?

MR. DAVISON: This is Paul Davison. From the perspective, you know, Bill mentioned that we have a normal everyday monitoring system that we use for troubleshooting monitoring the plant no different there. That's our normal monitoring system. We have stand-alone equipment that I mentioned which is not integrated into the station. That's why we keep it separate in the plant. We essentially bring the data to the control room for analyses. We have specific power plateaus and in our power ascension program. Specifically, at 105, 110 and 111.5, we will actually be submitting our data for NRC review, so we will actually have plateaus there. That will be the off-site interaction. Of course, our senior and resident inspectors will be, I'm sure, involved with --

MR. WALLIS: But just the inspectors

involved. Is someone here involved as well?

MR. DAVISON: That is correct.

MR. KOPCHICK: And I will cover that in a follow on slide. At our power plateaus, we actually have a 96-hour hold built in for concurrent staff review of our results.

MR. WALLIS: Is this done by some sort of computer display of what's going on or telephone or how does this happen, this interaction with NRC Headquarters?

MR. KOPCHICK: Well, we will -- as Paul Davison mentioned, we'll be gathering data incrementally upon receipt of the license change request. Obviously, we'll be gathering data and performing testing until we reach a plateau of 105% power. That information will then be gathered and presented to our plant operations review committee and then transmitted. And Paul, do we have some --

MR. WALLIS: So it's not online? It's not a sort of online thing?

MR. KOPCHICK: Paul Duke?

MR. DUKE: This is Paul Duke. Our current plan is that we are going to set up a provision for data transfer to NRR and to its contractor similar to what VY did, that is that the data files will be at an online backup location accessible to NRC staff and to its contractors.

MR. KOPCHICK: Okay. Regarding the conduct of testing, the testing includes both Level 1 which is termination criteria, and Level 2, which is hold acceptance criteria as well as steps to be taken should either of these thresholds be reached. The criteria used are similar to that used during the original Hope Creek startup testing, other EPU experience and the standard GE EPU testing specifications.

Non-test equipment or plant performance issues will be handled via the plant corrective action process. The plant operations review committee is responsible for reviewing the test procedure, changes, deficiencies, plant terminations or holds and power ascension to subsequent test plateaus.

As we previously discussed, we'll be establishing a power ascension control center which will be in our outage control center immediately adjacent to the control room, and this will support the test program. We have observed this also to be successfully used at another facility, which is Vermont Yankee.

So as Paul Davison previously mentioned, the shift will be focusing on operation of the plant. The power ascension control center involving the individuals in the previous slide that you saw will support and gather the data for the testing.

Testing will utilize a similar approach to that we had previously discussed at Vermont Yankee. Baseline data will be taken at approximately 90% and 100% of current licensed thermal power and evaluated to project results at higher power levels. Power escalation will proceed along the constant rod line using recirc flow at 2.5% increments. During power ascension, hourly collection of dryer strain gauge and vibration data is taken and moisture carry-over will be determined.

The power plateaus we previously discussed will occur at each 5% power level and the final power level, i.e., 105, 110 and 111.5% of current licensed thermal power. At each plateau, we will perform detailed evaluations, walkdowns, and the majority of our power ascension tests. Steam dryer performance data will be transmitted, as we discussed, to the NRC at each plateau followed by a 96-hour hold, as I previously mentioned. Management approval will be required prior to exceeding or proceeding to the next power plateau.

In addition to the specific tests performed, the test team will be continuously monitoring critical plant parameters under EPU conditions on affected systems throughout power ascension using EPU system monitoring plans. These system monitoring plans have been developed and include system baseline information at current licensed thermal power level, OE from a database, and determined expected EPU parameters and acceptance criteria.

MR. ZABIELSKI: We seem to have lost the --

MEMBER MAYNARD: Yes. We'll get somebody in here to take care of it. We have a handout to look out.

MR. KOPCHICK: Okay. The next slide is slide 24 labeled power ascension testing and major test evolutions. The power ascension tests were chosen based on a comparison of original Hope Creek startup tests and EPU changes considering the GE EPU test specifications and testing-related regulatory commitments. Overall, the plan includes 12 power ascension tests focusing on core performance, plant chemistry, radiation protection, nuclear instrumentation and pressure and feedwater controls.

Testing is consistent with those tests performed during the initial Hope Creek startup testing and that performed at other stations implementing EPUs.

Testing also focuses on steam dryer and nuclear steam supply system piping integrity and moisture carryover. Piping strain gauge data, as previously mentioned, will be collected and trended hourly during power ascension activities and evaluated. Moisture carryover will be determined every 2.5% increase in core thermal power.

As I mentioned previously, the specific tests themselves will be supplanted by system monitoring plans performed throughout the power ascension process as well as plant and equipment walkdowns in the field. These plans will ensure that the major EPU effected systems remain within analyzed limits as power ascension proceeds.

CHAIR ABDEL-KHALIK: So, typically, how long does it take to go through a 2.5% step?

MR. KOPCHICK: We have set up, in our submittal, for a 1% per hour ramp rate.

CHAIR ABDEL-KHALIK: One percent.

MR. KOPCHICK: So our schedule for power ascension is based on that rate. It also includes the holds that I previously mentioned at the plateaus at

5%, 96-hour holds. So the ramp rate is 1% per hour, so 2.5 hours to answer your question.

CHAIR ABDEL-KHALIK: And the data collection will commence once you reach steady state, or are you going to also collect data during the power ramp?

MR. KOPCHICK: The test procedure is set up for discreet data collection at each 1%. The systems, the computer systems that we have have trend capabilities, and we will be able to capture data live time as we raise power. However, the test program, which is modeled against what we have from Vermont Yankee, is discreet at 1% power. Paul?

MR. LINDSAY: I can offer at the 2.5% increments, there is a 4-hour hold period for all the systems to allow achievement of steady state, and that's when the data is essentially taken. So at 2.5% increments, we have a 4-hour hold. But of course, as Bill said, at the 5% power plateaus, we'll be holding for a 96-hour duration.

MEMBER ARMIJO: You mentioned a plant water chemistry test during power ascension. Is there anything special you're doing there or is it pretty much routine monitoring the various --

MR. KOPCHICK: As far as the plant

chemistry?

MEMBER ARMIJO: Yes.

MR. KOPCHICK: There are a battery of tests that we will accomplish. Most of them are routine. They do have Level 1 and Level 2 acceptance criteria. Level 2 would be to make sure that we are where we predict to be as far as conductivity in our condensate system as well as reactor water conductivity. Level 1 criteria would be associated with our technical specifications and UFSAR requirements. Anything else to add?

MR. LINDSAY: Essentially, what I could add is all the tests are the normal tests via the existing chemistry procedures. The key difference is the frequencies will be much higher. We have a shift lead daily, three times weekly readings. And certainly in the area of moisture carryover, where we take that, I believe, weekly at this time, we'll be taking that every 2.5%.

MEMBER ARMIJO: Yes. Where I was going with this is -- and you may have it later -- but you're going to be modifying your hydrogen input and how -- are you just going to just do it, or are you going to get feedback from electrochemical potential measurements in the startup?

MR. KOPCHICK: Operationally, our intent is to maintain our current injection rate of 9 standard cubic feet per minute. And Paul has some details on the testing we intend to do once we would achieve 111.5.

MR. LINDSAY: Well, essentially, as Bill said, our hydrogen injection system will be placed in manual for the duration of the testing so that we do not artificially influence like the rad surveys and things of that nature. When we achieve 111.5% power, we have an existing procedure which will alter the injection rate and determine the optimum level.

MEMBER ARMIJO: What's required based on what kind of a monitor, an EPR, electrochemical potential measurement or some other --

MR. LINDSAY: I believe that's correct.

MR. DAVISON: Paul Davison. For the part of the noble metal chemical application which allowed us to reduce our hydrogen injection rates, our reactor water cleanup system has two types of monitors. One, we have the durability monitors where we're able to take coupons out and do samples. We also have the ability to do the ECP measurement directly.

MR. WALLIS: I'm still curious about with the NRC is doing all this time. Is there somebody here all the time paying attention to this, or do you all disappear for the weekend so that that's why there's a 4-day hold period. No, seriously, I mean, what is the NRC doing through this process? Is somebody here sort of monitoring things all the time, or is this person available in several hours, if needed, or what?

MR. LAMB: This is John Lamb with the NRC. The mechanical engineering branch will look at this and, obviously, when they send that in, it's a 96-hour hold, because that gives us time to actually analyze it. So yes, regardless of when it gets sent in, we will be available during that time. I think during Vermont Yankee --

MR. WALLIS: So someone will -- should be available all the time?

MR. LAMB: Yes. Like I said, they get the information. Then they start analyzing it and if they have a problem, then obviously, we'll be on the --

MR. WALLIS: So there isn't a here, this person will work on the weekend if it's over a weekend?

MR. LAMB: Yes.

MEMBER MAYNARD: That's also been my experience at the resident inspector state --

MR. WALLIS: Yes. I can understand that --

MEMBER MAYNARD: -- very involved with these.

MR. WALLIS: I just wondered about the NRC and when I come here on the weekend, there's nobody here so I --

MR. LAMB: Well, this would be a special case, obviously, during this --

MEMBER MAYNARD: There is always a number 24 hours a day, 7 days a week to get a hold of someone.

MR. KOPCHICK: I would certainly add that the resident inspector is highly engaged in our activities in the control room, and when we proceed with this test, I would expect that he would have many questions for us and has asked questions along the way. Our rapport with the resident has been sound and it's also my expectation from my shift managers that if there is any upset or any transient that would require notification or activation of station personnel to investigate an event, that the resident is informed, and it's actually part of our procedures that we do inform them.

CHAIR ABDEL-KHALIK: Now will you be

presenting details tomorrow regarding the procedures and instrumentation, etcetera for the steam dryer verification work? Does this require a closed session, because this is sort of a generic big picture of what you're going to do, but people want to know the details of how are you going to do it.

MR. KOPCHICK: Yes, sir. We -- for the additional hour, I believe for the second session yesterday (sic), we will have a presentation --

CHAIR ABDEL-KHALIK: Tomorrow?

MR. KOPCHICK: -- tomorrow, correct -- that will detail the testing work we need to do on the steam dryer and what the acceptance criteria will be in detail. Paul Davison, do you have anything else to add on the hour portion tomorrow?

MR. DAVISON: Paul Davison. That is correct. We will be providing additional details with respect to not only the complete testing matrix of what we do at each particular power level but what we do with the data, what the analysis is and how does that factor back in, specifically on the steam dryer with the limit curves and flow-induced vibration monitoring acceptance criteria that we have.

CHAIR ABDEL-KHALIK: Thank you.

MR. DAVISON: Welcome.

MEMBER BONACA: I have a question regarding -- in your application, there is a statement or a discussion that flow-induced vibration during power escalation may increase SRV leakage. Are you monitoring for that?

MR. KOPCHICK: We do have strain gauges installed on main steam piping, accelerometers installed on main steam piping to include SRVs. As a test manager, there is an attachment in our test procedure that will be executed as we raise power, and there are some more details on that that I will ask Mr. Davison to add.

MR. DAVISON: Yes. As mentioned, in the modifications, we did install numerous accelerometers. For example, our critical systems that will be monitored with Level 1 and Level 2 acceptance criteria -- extraction steam, the SRVs, both the actuators and the tailpipes on a few of the SRVs, the recirc system, feedwater, and main steam. So for example, baseline data right now on main steam, we're at .035 g's. That's RMS value. We anticipate that it will go to approximately .048 g's which is, you know, obviously well-below the .1 g standard for low vibration.

MEMBER BONACA: Because from the application, it sounded like you had a program to monitor, in fact, leakage when you wrote the application, and evidently, must that be successful in controlling --

MR. KOPCHICK: SRV leakage at Hope Creek has not been probably as pervasive as some other stations have had. Nonetheless, in the development, at least in my discussions with engineering personnel who have been involved, I know that the attentiveness to that has been high, thus the reason for the installation of the accelerometers.

MEMBER BONACA: So I guess you don't expect the uprate to result in unacceptable performance from a leakage standpoint?

MR. KOPCHICK: I do not. Obviously, we'll be monitoring that. Anything else to add, Paul?

MR. DAVISON: Yes. Paul Davison. We've done a few things. One, we specifically have done some upgrades to our pilot valves. We have two-stage target rock relief valves. We've had excellent performance with respect to tailpipe or through-seat leakage as well as repeatability when we do our testing out of refuel outages. The specific reason for monitoring both the actuator valve body and the tailpipes was due to the industry operating experience, like at Quad Cities where they electromatic relief valves experienced a high amount of resonance and were actually getting damaged. Based on our baseline readings, don't anticipate that. Based on our steam-line flow characteristics, we would not anticipate that occurring as well. But that's why it will be carefully monitored.

MEMBER BONACA: Okay. Thank you.

CHAIR ABDEL-KHALIK: So what is your history on SRV testing as far as setpoint drift?

MR. KOPCHICK: Setpoint drift testing -- well, I know there is a population of SRVs that we're required to test each refuel outage. Operationally, as far as setpoint drift, I don't know that I can specifically speak to that as far as the results go. From the operator perspective on SRV setpoint or leakage or lifting, we have specific procedures that the reactor operator will monitor tailpipe temperature twice each shift with specific guidance.

MR. DAVISON: Yes, this is Paul Davison. We have tech spec required 3% band allowable value for the setpoints. We have not experienced large numbers of failures with respect to those -- to that setpoint band itself.

CHAIR ABDEL-KHALIK: Have you experienced any failures?

MR. DAVISON: Yes, we have. I can get the specific data on the failure rate of those.

MEMBER BONACA: And the reason why I raised that issue was that in the statement, the application speaks specifically about a program that you had to resolve problems resulting in SRV surveillance testing exceeding a 3% tolerance. You must have experienced that? I mean that's what you have in your application?

MR. DAVISON: Yes. We'll get the specifics on that.

MEMBER BONACA: That's why I was wondering if, in fact, the power uprate would make it more challenging just because of that.

CHAIR ABDEL-KHALIK: We're interested in that. We're also interested in any incidents in which the SRVs failed to open.

MR. DAVISON: I understand. Failure to opens as well as setpoints history.

CHAIR ABDEL-KHALIK: Okay. Thank you.

MR. KOPCHICK: Okay. I'll proceed on. Similar to the initial startup testing, power ascension data, evaluations and results will be summarized in an EPU power ascension report. Post-EPU, ongoing monitoring and inspection efforts will continue throughout the cycle and in RF-15.

In summary, Operations, myself included, is ready to lead and support and the station's power ascension test program and considers the station well-prepared to execute a careful monitored approach to the target EPU power level. This concludes the operations and testing portions of the presentation pending any additional questions.

CHAIR ABDEL-KHALIK: Are there any questions for Mr. Kopchick? Okay. Thanks. We're well ahead of schedule, but at this time, I'd like to take a break for 15 minutes and we will reconvene at 10:30.

(Whereupon, off the record at 10:16 a.m., and back on the record at 10:34 a.m.)

MEMBER BANERJEE: We're back in session. Before we get started with the staff's presentation on human performance, Mr. Davison has some information regarding the power ascension test matrix that he would like to present, and I guess more details will be presented tomorrow.

MR. DAVISON: Yes. Thank you. Paul Davison. As a follow-up to the questions asked earlier when Bill was speaking with respect to Operations, this was a chart or tabular form of the testing that we'll be performing. We'll modify this and I'll talk specifically to what will occur up to and including 115% power. This just reflects our current test plan, if you will, for this cycle to 111.

What this shows, in a broad view, is on the y axis is the power level. You see 90 and 100 are really baseline testing, and then we go 101, 102. Those are those 1% steps Bill talked about. The 102.5 is a stop-point for us to take additional data. And then what you see in -- and it just goes all the way up to 111.5 -- some clarification on that -- the rows in red, 105, 110 and 111.5 CF are the NRC-required data transmissions. Those are the actual data packets that will be sent of all the tests at those requirements of our licensing condition.

Two other clarifications -- the 111.5 verus 111.5 CF -- the CF stands for cross-flow -- so we'll bring the plant to 111.5%. We have a data collection making sure we don't have any issues with our cross-flow system, and then we'll put in the correction factor of our venturis and maneuver to the true most accurately defined 111%. That's why you see 111.5 twice on the chart.

The second clarification will be we will extend that so you see what it looks like all the way to 115%. This only, right now, captures our current test plan for this cycle.

MR. WALLIS: So when you send this data to the NRC, do you just send the whole other curves with wiggles, or do you send some comparison with criteria which have been established ahead of time or something like that? What is it you send to them?

MR. DAVISON: We will send them all the data. We will also send the comparisons which have specifically defined acceptance limits in that.

MR. WALLIS: Okay. That's helpful.

MR. DAVISON: Correct. And it'll be the same information we'll be sharing with Operations to ensure that they're ready and concur with moving to the next power level as well.

Across the top of the chart, percent power being the leftmost column, the rest of the columns are all the different tests that Bill went through. You know, we talked about chem data. We talked about the flow-induced vibration. I spoke to that.

The three grayed columns are the tests that most translate to dryer performance -- main steam on strain gauge which will be used to base off the strain gauges, the loads that are going and inputting on the dryer, running it through the finite element analysis and coming up with the loads.

The moisture carryover Bill talked specifically -- another secondary indication of some type of dryer failure that would allow additional moisture to carry over.

And then the main steam line accelerometers will be used as a comparison and validation of the strain gauge data to make sure that there is no anomaly in the data where we're extracting the dryer loading from the strain gauge data itself. So those three columns grayed out are really specifically related to the dryer. The rest of them are just all of the bulk testing that we'll be doing to make sure there's no other undetected anomalies in the plant.

Tomorrow we'll go through the actual specifics with Dr. Alan Bilanin here to actually go through how we're going to do the analysis, what the results will look, the graphs, the information that we'll have to determine that we're below Level 1 and Level 2 criteria and what happens when we go above the Level 1 or Level 2 criteria.

CHAIR ABDEL-KHALIK: The test matrix at 115% will be identical to that at 111.5%, the very last column --

MR. DAVISON: That's correct. The repetitiveness of that chart will continue down through 115% ending in 115% with cross-flow applied the whole data string across. So that'll just be a continuation of that chart and we'll have that tomorrow.

MEMBER ARMIJO: And that'll all be completed in the following cycle, Cycle 16?

MR. DAVISON: No. We have no commitment for actually uprating to the full 115% in our next cycle. Primarily, what we wanted to do is get the plant to 111.5%. That allows us to do all of our testing, ensure that there are no anomalies. We will monitor the plant's performance in the summer which is the most taxing time of the year for the plant with respect to performance. That data can then be utilized to work with General Electric on what modifications we may be doing on the high-pressure turbine.

Of course, the modification process that I'm responsible for at the station has a lead time. Of course, the manufacturing process for General Electric -- so we would not be putting that into the next cycle just because we physically couldn't get it done. Of course, we'd have to do all the business analyses, because along with this, we'll be looking at our cooling tower performance for summer months.

There is a whole environmental licensing and modification process that would have to be followed with respect to an addition of the cooling tower to the site, a helper tower, if you will, if that's what we need to do with our cooling tower.

So we do not have specific plans for the next cycle, Cycle 16, only because of when we'll be implementing this and the shortness until when that next refuel outage is, which is in the spring of 2009.

MEMBER ARMIJO: Okay. But the 115% testing will be done when you finally get --

MR. DAVISON: Correct, whether it was a week later or five cycles later, our commitment will be as soon as we go 111.5%, the next plateau, this test matrix is back in place. Our testing center is back and all the exact same testing methodology is reapplied including transmittal of data to the NRC.

CHAIR ABDEL-KHALIK: Thank you for the clarification.

MR. DAVISON: You're welcome.

CHAIR ABDEL-KHALIK: At this time, we'll proceed with the staff presentation.

MS. MARTIN: Good morning. I'm Kamishan

Martin and I did the review for the human factors portion of this EPU submittal. As you can see, we reviewed the EOPs, AOPs, any human system interface changes, SPDS, and training and simulator issues that may have come up, and we wanted to ensure that this did not affect the operator's performance adversely.

It's pretty straightforward. We didn't have any new manual actions or changes to the mitigation philosophies for the EOPs or AOPs. There were some modifications to the parameters and some of the levels because of decay heat because of the EPU, and there were some setpoint changes as well.

In the realm of operator actions, we had no new operator actions and the response times in their safety evaluation that they credit are unchanged, and the available times for the manual actions and the action times for the manual actions remain unchanged.

CHAIR ABDEL-KHALIK: Now there was a question raised earlier about operator and manual actions following an ATWS. And the question is do the available times for manual actions change as a result of EPU conditions?

MS. MARTIN: Okay. As part of my review, I was informed that the manual action times -- you mean the actual time it takes the operator to perform the action -- does not change -- is that what you were asking me?

MR. WALLIS: Well, usually, it does in an EPU.

MS. MARTIN: The actual time it takes them to do the action?

MR. WALLIS: No. The available time.

MS. MARTIN: Available time?

MR. WALLIS: Right.

MS. MARTIN: I asked specifically, as part of my review, do any of the actual -- available times for the operator change, and I was told there weren't change --

CHAIR ABDEL-KHALIK: So this statement is based on response provided by the applicant rather than an assessment as to whether or not there is a potential for a change in the available times in events such as ATWS required operator action to reduce water level in the vessel?

MS. MARTIN: I'm sorry, could you restate that?

CHAIR ABDEL-KHALIK: This statement or this conclusion that the available times for manual actions credited remain unchanged is simply based on input provided by the applicant rather than an assessment, an independent assessment on your part as to whether or not the available times would change?

MS. MARTIN: Yes.

CHAIR ABDEL-KHALIK: Okay. Would the applicant care to provide any input into this as to whether or not the available times would change?

MR. DUKE: This is Paul Duke. The number of operator actions that are credited in design basis analysis are relatively few. However, their times are not changed. For example, in the containment response analysis, it is assumed that containment cooling is put into service after 10 minutes. That remains the same. We understand the specific question with regard to ATWS and water level, and we'll get additional details on that specific question today. But in general, the number of operator accidents credited are relatively few in any design basis analysis and they have not changed.

CHAIR ABDEL-KHALIK: I understand the specified times in the procedures may not change, but the analysis may indicate that the available times may have changed, and that's the purpose of the question. What is the change in the available times?

MR. DUKE: Well, for the example of the

containment response, the actions to put containment cooling in service are no different for EPU versus current licensed thermal power.

MR. WALLIS: I think it's the level control that has to be done a little quicker.

MR. BOLGER: This is Frank Bolger from GE. I wanted to point out that the Hope Creek does have a system by which when there's a high pressure trip, that will initiate a feedwater runback approximately 25 seconds after the pump trip. It also has an automatic initiation of the SLC system.

MR. WALLIS: Yes., I think we've heard that earlier, but usually, the level control shows up when they do their probablistic safety analysis because it turns out that the operator has less time and then this, by some magic, is transferred into a CDF. And this is usually how the CDF changes or one of the dials that changes the CDF when you have an EPU. I was a bit surprised that Hope Creek wasn't a bit more specific saying its 10 minutes changes to 7 minutes or something specific like that.

CHAIR ABDEL-KHALIK: Is your implication --

MR. WALLIS: we're going to hear about that later, right?

CHAIR ABDEL-KHALIK: -- that these automatic actions -- as a result of these automatic actions, the available time for operator action from lower to moderate levels do not track.

MR. BOLGER: This is Fran Bolger again. There may be some other scenarios at which those automatic actions would not occur. For example, if the high-pressure trips do not occur, in those cases, I think I would have to defer to PSEG for their training of their operators.

MEMBER MAYNARD: I think we may be talking about -- I don't know -- but I think it's important that we get the distinction. I mean there's three times that we're talking about -- the time that it takes the operator to do an action, and apparently that hasn't changed; the time credited for operator action, and certainly that hasn't changed; but time available before you would run into exceeding some limit, I think, surely has to have changed for some of these. It may not have changed any operator actions or the time credited but I think that some of the time before you would exceed a limit probably has changed.

MR. WALLIS: The available time must have changed.

MR. DAVISON: Correct. This is Paul

Davison. PSEG understands the question and we will provide a formal response to that so we can get you an accurate answer to your question on available time.

CHAIR ABDEL-KHALIK: Thank you. Please proceed.

MS. MARTIN: I also looked at the human system interfaces and they didn't indicate any changes that would occur due to the EPU that would affect the operator's ability to interpret or visually see anything they needed to. All of the changes will be used with the design change process of PSEG.

The SPDS has a re-scaling in input-output changes to feedwater control parameters due to the EPU, and these are the curves that will be impacted by the EPU. The training for operators to cover all the changes due to the EPU will occur prior to implementation, and these adverse event the simulator updates that will occur due to the --

MR. WALLIS: Excuse me. Did anybody check that these changes were appropriate? I mean we saw all these changes to these curves. Did anybody check that they're appropriate or you just accept the curves as submitted?

MS. MARTIN: I don't actually look at the curves. That's another group. Reactor Systems looks at the acceptability of the changes to the curves.

MR. WALLIS: Reactor Systems looked at those?

MS. MARTIN: Yes.

MR. WALLIS: Okay. So there was someone who did review whether these were appropriate --

MS. MARTIN: Yes. That's later on. Because of the few changes to credited operation actions --

CHAIR ABDEL-KHALIK: Could you please go back to the previous slide? Now you had gone through this. Now my understanding is that operator training has already been conducted. Is that correct?

MR. KOPCHICK: The question was has operator training already been conducted prior to plant operation at EPU conditions. That is correct. Operator training on transient, steady-state, and power ascension testing was completed. We also will perform just-in-time training with each operating crew prior to implementing the power ascension test procedure.

CHAIR ABDEL-KHALIK: And the, I guess, the simulator validation verification has already been completed at 11.5% or at the 15%? You have two modes of operation for the simulator?

MR. KOPCHICK: Yes, sir, we do. We operated the simulator at 111, 115% power to validate that the simulator's response, as required by ANSI 3.5 and balance-of-plant testing, was acceptable. What is outstanding by PSEG process is to document the results of the that testing by our station procedures which would then formally document the completion of the ANSI standard test by April 13th.

CHAIR ABDEL-KHALIK: But nevertheless, you went ahead and conducted the training --

MR. KOPCHICK: That's correct.

CHAIR ABDEL-KHALIK: -- with the simulator as is?

CHAIR ABDEL-KHALIK: Yes, sir.

MR. DAVISON: Paul Davison. And the final piece of that -- well, once we operate the plant physically at that new power level, there will be other comparisons and validation back to the simulator with real plant data.

CHAIR ABDEL-KHALIK: Thank you.

MS. MARTIN: In conclusion, with respect to human factors and the changes that will be made due to the EPU, we found the things that were identified by PSEG to be acceptable and that's it.

CHAIR ABDEL-KHALIK: Any questions for Ms.

Martin?

(No audible response.)

CHAIR ABDEL-KHALIK: Thank you.

MEMBER BONACA: You will have an answer to the question that you raised before regarding available time, right?

CHAIR ABDEL-KHALIK: Correct. Yes, the applicant will provide a response.

MR. DAVISON: That's correct.

MR. RAZZAQUE: This is Muhammad Razzaque and I need to make an announcement. We agreed that we'll be presenting early, but one of our reviewers got an emergency call, and he is out now. He may not be here in this period, so if there is any questions me or Tony cannot answer, we have to get back to you it looks like.

CHAIR ABDEL-KHALIK: Now we can probably proceed with your part of the presentation and then take a lunch break. And then at that point, we'll make sure that everybody on your team who can directly answer any questions that might come up can actually be here.

MR. WALLIS: Excuse me. We're hearing the staff's view of these things before we hear the applicant's?

MS. ABDULLAHI: It's an open and closed session.

MR. WALLIS: Oh, it's an open and closed.

MS. ABDULLAHI: Right. This would be an open session --

MR. WALLIS: Then we're going to have a closed session from the applicant. That's why we're doing it in this order?

MR. RAZZAQUE: Myself again, Muhummad Razzaque and here, Nakanishi. Two of us will present most of the material. Tony will discuss the fuel methods, and I will provide the rest of the information. I was mentioning about the reviewer, Dr. Tai Huang -- he got the emergency call out, so he should be back whenever he is.

MS. ABDULLAHI: This is Zena. If there's a section, he's covering, we'll just postpone and reschedule within some other slot.

MR. RAZZAQUE: Okay. He is -- he was not planning to present unless -- as a support he was here. Review scope -- the assistance branch looked at the fuel system and nuclear design, thermal-hydraulic design, overpressure protection, SLC system, transient analysis, LOCA, ATWS and GE methods which Tony is going to talk about after me.

Fuel method was based on the generic accepted -- NRC-accepted guidelines which basically are ELTR-1 and ELTR-2. Although this is a constant pressure uprate since there is some legacy fuel still in there, although they should not be limiting -- they will be non-limiting, still, technically, ELTR-1 and ELTR-2 is the main guidance that were followed. And all of them are NRC-approved methodologies.

The ACR was written on the format RS-001. Review of system and nuclear engineering design, Cycle 15, the current cycle which would be the first EPU cycle, predominantly GE fuel and some remaining average of thrice burnt Westinghouse fuel, SVEA-96 fuel. SVEA-96 is expected to operate at less than -- well-below GE power and also at pre-EPU level and expected that it will not be limiting. It will be the GE fuel which should be the limiting.

MEMBER ARMIJO: Now I'm a little confused. I heard or I saw in one document that there was some twice burnt SVEA fuel in the core right now --

MR. RAZZAQUE: Yes.

MEMBER ARMIJO: -- and it's to just thrice burnt?

MR. RAZZAQUE: That's right, eight of them to be exact. Out of 764, 216 is the SVEA fuel. And out of 216, 8 are twice burnt and the rest are thrice or more. So on the average, their burn up is thrice. Average burn up in the core is thrice.

MEMBER ARMIJO: Okay.

MR. RAZZAQUE: We can get --

MEMBER ARMIJO: You'll show us on the core map where those things are?

MR. RAZZAQUE: Do you have that, Tony?

MR. NAKANISHI: We can provide that. This is Tony Nakanishi with Reactor System. We can provide that or the licensee may even --

MEMBER ARMIJO: Yes, if PSEG is going to show that, I can wait.

MR. RAZZAQUE: Right. And we requested for the power level that is expected in SVEA fuel compared to GE fuel, and we have verified that it is well-below GE power level. The way they placed them in the core, particularly those eight bundles, the power is still well-below GE bundle power level. That we have verified.

Each bundle power will increase by about 4.4% which is the exact number being -- 6.8 megawatts thermal to 7.2 megawatts thermal, which is about 4.4% and which is within the experience base that EPU has. Normally, it ranges from 3 to 5-6%.

MR. WALLIS: Why do you put thermal in here?

MR. RAZZAQUE: Pardon me?

MR. WALLIS: I just wonder why you had to put thermal in here? I mean would it be anything else but thermal power you worry about?

MR. RAZZAQUE: Just to show how the big bundle increases, what percent the big bundle increased. That's just to give you an idea. It is not a thermal limit. Just to give a sense. We know that the average bundle increases 15%.

MR. WALLIS: Yes.

MR. RAZZAQUE: And big bundle doesn't stay the same. It increases a little bit. That's all we are trying to say. And it varies sometimes 5%, 6%. This plant happened to have 4.4%. It's just a piece of information. There is no regulatory connection to that.

The thermal limits are the fourth bullet, SLMCPR, OLMCPR, MAPLHGR, and LHGR, those are the legal limits that have to be met. And they are determined for each reload cycle including any mid-cycle modifications which, in this case, will be the EPU. And the hot excess reactivity and shutdown follows GESTR-II which is the approved GE method.

Thermal hydraulic design stability relies on Option-III, and reload analysis will follow the staff-approved methods and hence acceptable. Equipment and startup reveal no changes required. So this is information which was verified by the staff that the equipment -- there was no change required for the EPU as far as the equipment is concerned. Setpoints for detection and suppression established using the approved methods. And there will be a generic penalty on the bypass void penalty as required by the generic report, NEDC-33173P-A.

MEMBER BONACA: Now in addition to -- I'm sorry.

CHAIR ABDEL-KHALIK: Go ahead, please.

MEMBER BONACA: In addition to the Option-III long-term solution, there is a backup system, right?

MR. RAZZAQUE: There is a back up system?

MEMBER BONACA: I'm sorry?

MR. RAZZAQUE: Yes, there is a backup system.

CHAIR ABDEL-KHALIK: Now this change, 11.5% power increase, will have a mid-cycle, so the core that's in there is the core that's going to be operated at 111.5%?

MR. RAZZAQUE: Right.

CHAIR ABDEL-KHALIK: The reload analysis that was presented prior to the beginning of Cycle 15, were these analysis performed at the current licensed thermal power?

MR. RAZZAQUE: It was at EPU. There has been a server provided to the staff for EPU and that is what we looked at for EPU. There may have been one done for the current power level, too, but we didn't look at that. We look at the EPU server to verify some of the conclusions that we made.

CHAIR ABDEL-KHALIK: Okay. Thank you.

MEMBER BONACA: So I'm trying to understand -- the protection system is already set at 115% power, and then you're operating all the way down from 100% which is now going to be maybe 90% or whatever to 97% and then later on to 100% of 115% power? That's what you've done?

MR. RAZZAQUE: We are approving 15% and we're expecting that will bound everything below. So we reviewed one analysis which is 115%. There is the ultimate objective. So based on that 115%, the analysis -- the results that I will present will be, again, based on the 115%. The first one here is the overpressure protection results which was typically done at 102% of 115%.

CHAIR ABDEL-KHALIK: Now in your assessment of the overpressure protection, have you looked at the history of the Hope Creek SRV performance?

MR. RAZZAQUE: We did not specifically look at the history.

CHAIR ABDEL-KHALIK: So what assumptions are made in your assessment of the peak pressures calculated --

MR. RAZZAQUE: One of the key --

CHAIR ABDEL-KHALIK: -- pressure transients?

MR. RAZZAQUE: One of the -- there are few key assumptions. One is that the SRV drift setpoint will be within 3% plus or minus. That is the approved limit. Another key assumption is that out of 5 SRVs -- I believe I remember the number correctly -- one will not open at all.

CHAIR ABDEL-KHALIK: Okay. Now --

MR. RAZZAQUE: Those are the like assumptions that we look at --

CHAIR ABDEL-KHALIK: The question still remains. Does the history of Hope Creek SRV performance comply with the 3% tech spec limit on setpoint?

MR. RAZZAQUE: My understanding is that it should be -- it's required to be, because tech specs require that they have to be within plus or minus 3%. And also, the -- it may be -- the licensee may correct me, but for each cycle, each outage, they have to take certain number of those SRVs and test and see whether it stayed within that band.

CHAIR ABDEL-KHALIK: I fully understand that. But the question is have you done an independent examination as to whether or not this assumption is indeed valid?

MR. RAZZAQUE: We have not done that independent verification. There are certain guidelines and regulations that the licensee will have to follow. And as I said, that's what it is. Each outage they have to be tested, and if it is exceeded 3%, it should be reported to NRC as a routine basis. And when it is put back, it should be refurbished back to 0% -- or within 1%, I think.

CHAIR ABDEL-KHALIK: So you do have access to that information because if the setpoints had indeed exceeded the 3% limit, they would have notified the NRC.

MR. RAZZAQUE: It is reported by

regulations, I think. That's my understanding -- it is reported as the LAR. And there is a whole data available for each plant, so if we wish to, we could go back and review it.

MR. DAVISON: That is correct. In addition to the -- Paul Davison -- in addition to the history that I'll be providing to you -- we're pulling that for you now -- in the event that we have a number of SRVs that would fail their 3% accuracy requirements, we would have submitted that for the LER process. That would have been a violation of our tech specs that would have been clearly transmitted to the NRC. But I will have the full listing of our failure rates to the subcommittee.

CHAIR ABDEL-KHALIK: So if indeed there is sort of a trend or a history of failure to meet the tech spec limits or failure to even open, would the staff go back and re-evaluate the overpressure analyses in light of that data?

MR. RAZZAQUE: I'll tell you what we did. Many years ago actually, I was directly involved in that. It was a tech spec limit was 1%, plus or minus 1%, and the industry found that this is too tight. They couldn't maintain that. So they came to NRC for approval to 3% hoping that that will cover the real world. And we did an extensive review on that, looked at the data set and everything based on industry. And we also agreed to that, that 3 would be a reasonable number. And we haven't done anything after that -- that is true -- except that if there is a noticeable trend we observe, we will get to that specific licensee. But generally, it is approved for 3%.

CHAIR ABDEL-KHALIK: So without sort of --

MR. RAZZAQUE: And it was based on a study done and found to be industry-wide -- to us, found acceptable to extend the range up to 3% without affecting these results significantly -- I mean staying within the limits and sort of like a tradeoff. Like you're to be realistic. At the same time, we have to meet our regulation. And 3% was decided that was the one.

CHAIR ABDEL-KHALIK: So we will await the data to be provided before we may possibly revisit this issue.

MR. DAVISON: Correct.

CHAIR ABDEL-KHALIK: Thank you.

MR. RAZZAQUE: And based on those assumptions that I mentioned, the results came out to be within the limits. Obviously, they have to be to -- 1285 psig, and they have a tech specs limit which is

1325 psig, and they met that. And SRV setpoint changes were not necessary because it was a constant pressure power uprate. Again, this would be analyzed each reload. Each reload, it will be re-analyzed.

Standby liquid control system, as the licensee indicated, they have both features normally as well as -- the normal is manual, but it can be automatic. The 86 gpm boron equivalency is satisfied. We verified that. Sufficient margin in the pump discharge relieve vales. Since the pressure increased a little bit, the discharge pressure also increased a little but. But still, there is plenty of margin at the setpoint.

CHAIR ABDEL-KHALIK: I'm sorry, which pressure has increased?

MR. RAZZAQUE: The discharge. The peak pressure in the vessel will increase because of the EPU.

CHAIR ABDEL-KHALIK: Okay.

MR. RAZZAQUE: And therefore, the pump discharge pressure will increase, and we have to make sure that the -- it's not too close to the SRV setpoint. Otherwise, there will be an opening. And that was verified and found to be a sufficient margin.

MR. WALLIS: So you're saying that they do not open during --

MR. RAZZAQUE: They do not -- they're not expected to open, but in the analysis, one is allowed to open. In the analysis --

MR. WALLIS: It's allowed to open.

MR. RAZZAQUE: -- one is allowed to open. Concentration -- 660 production manager does not change from before EPU or after EPU, and it is confirmed for every reload cycle, before every reload cycle.

CHAIR ABDEL-KHALIK: So with the core design, it turns out that it takes the same boron concentration to provide adequate shutdown margins if all the rods are not inserted? It turns out to be exactly the same? Is this fortuitous?

MR. NOTIGAN: This is Don Notigan, PSEG. We've confirmed no change in the amount of standby liquid control system for cold shutdown at EPU.

CHAIR ABDEL-KHALIK: Okay.

MR. RAZZAQUE: If you like, I can add to that. The just plain -- higher power does not necessarily change the concentration. It is a combination of things like fuel batch fraction, enrichment or new fuel design. Those we may change but this part alone will not do it.

CHAIR ABDEL-KHALIK: I understand.

MR. RAZZAQUE: And it doesn't change here. AOO transient analysis, there are three categories of transient analysis broadly can be divided. One type is to set the operating limit MCPR, and it turns out to be turbine trip which is the one that set that.

MEMBER BANERJEE: With or without bypass --

MR. RAZZAQUE: No bypass.

MEMBER BANERJEE: We thought that with bypass, sometimes it's more limited.

MR. RAZZAQUE: It could be, but in this case, the -- as I'll show, either load reject nor bypass -- turbine trip --

MEMBER BANERJEE: Are we going to discuss this in more detail later one, these matters?

MR. RAZZAQUE: No, not -- we don't plan to. We look at the limiting events and for each category. There are several analyses required by ELTR-1 to be performed and find out which is the limiting one. It turns out --

MEMBER BANERJEE: Well, let me understand this. Do you do the uncertainties? In the void correlation, there's a penalty put on the OLMCPR? How much is that. Point?

MR. NAKANISHI: This is Tony Nakanishi. Point o one -- .01.

MR. WALLIS: I'm sorry. I'm confused. I'm looking back at my notes. The peak ATWS pressure is 1400-and something? We're trying to figure out these pressure limits you've got here. Is ATWS something different from what you --

MR. RAZZAQUE: Like the previous slide?

MR. WALLIS: -- different from what you're talking about with overpressure protection? You're going to talk about the ATWS pressure in some place? Because if the ATWS pressure is higher than the SLC pressure, that gives rise to recirculation --

MR. RAZZAQUE: Are you talking about the MSIV closure?

MR. WALLIS: No. I'm talking about the ATWS situation where the peak pressure is higher than the SLC pressure so that you get recirc -- SLC valve opens, overpressure valve opens during an ATWS, recirculates for a period of time. The pressures are higher than the pressures you talk about here. That's a different topic, is it? You're going to talk about that sometime or is someone going to talk about that?

MR. RAZZAQUE: This is all that you are seeing is for the MSIV closure with --

MR. WALLIS: Right, but the ATWS has higher pressures than that.

MR. RAZZAQUE: ATWS pressure, we are going to talk about ATWS.

MR. WALLIS: At some other time, okay.

MR. RAZZAQUE: Yes. Actually --

MR. WALLIS: I was just wondering -- trying to put this in context. You're going to get to that at some -- okay -- that's all right.

MR. RAZZAQUE: Yes. We were talking about the AOOs, anticipated operational occurrences, and they're -- that's --

MEMBER BANERJEE: They have some Westinghouse fuel in there. That GE method is sort of approved for this?

MR. NAKANISHI: This is Tony Nakanishi. We'll discuss more in terms of the GE methods capability to model SVEA fuel, but we --

MEMBER BANERJEE: So will you go into the OLMCPR at that point a little bit?

MR. NAKANISHI: Sure. I guess we need to be careful not to get into proprietary information.

MEMBER BANERJEE: Right. Well, when are we going to close the session?

CHAIR ABDEL-KHALIK: Immediately after

lunch.

MR. RAZZAQUE: Tony will discuss about that matter at that time. The second category --

MEMBER BONACA: What about SLMCPR, are you going to discuss that as well?

MR. NAKANISHI: We certainly can and the planned presentation wasn't covering that, but we can certainly discuss that further as a --

MEMBER BONACA: So -- but somebody's planning to talk about ATWS?

MR. RAZZAQUE: Yes.

MEMBER BONACA: I didn't hear -- yes. Okay. So there will be a discussion. I agree with you that it is not part of the anticipated occurrences, but we'll talk about ATWS.

MR. DelGAIZO: Excuse me. I'm a mechanical engineer on the EPU project. On the question of the SLC relief valve, the analysis -- when SLC is credited in the analysis, those peaks have all passed. The timer which has the time delay, it ensures that SLC is initiated so that the peaks are gone and the relief valve does not lift. However, if the system is initiated earlier and the relief valve does lift, there's a large margin required on the reset to be sure that that relief valve is closed before SLC is required in the system. So the relief valve could lift. It will recede. And if it goes on the timer, it will not lift. And that's how the analysis deals with it.

CHAIR ABDEL-KHALIK: But we will discuss ATWS at a later time if necessary in the closed session.

MR. RAZZAQUE: I was going to present the result here in the open session.

CHAIR ABDEL-KHALIK: We'll do that after lunch. But specific questions regarding operating limit MCPR and safety limit MCPR, if necessary, we can discuss them in a closed session. Please continue.

MR. RAZZAQUE: Okay. The overpressure event is the MSIV closure with flux scram, and the minimum water level transient is the loss of feedwater flow.

LOCA wasa based on SAFER/GESTR codes using equilibrium core. The licensing basis PCT for GE-14 was 1380 degrees Fahrenheit; and for SVEA-96, it was 1540 degrees Fahrenheit.

CHAIR ABDEL-KHALIK: Now this is an interesting result. I mean we've been told that this legacy fuel has a lot lower power than the GE-14 fuel, and yet your LOCA analysis calculates a higher peak pclad temperature in the legacy fuel than in the GE-14 fuel. Could you explain physically what's going on?

MR. RAZZAQUE: Yes. I'll try to explain. And basically to give some understanding how -- and I'll explain my understanding of how GE calculates these numbers. And the way these numbers are --

MR. NAKANISHI: It's not proprietary, is it?

MR. RAZZAQUE: Pardon me?

MR. NAKANISHI: Is it proprietary?

MR. RAZZAQUE: I don't think so. It's a methodology -- should know. Yes, SAFER/GESTR method. Yes, that is proprietary. I'm not talking about that, but the process -- I'm talking about the process. The process is that you assume equilibrium core, and equilibrium core assumes one kind of fuel, either GE-14 or SVEA-96. It doesn't assume at the same time. It does assume one at a time. Okay? So you calculate use, for example, with GE-14 fuel, but the key parameter which affects the PCT is the value of the MAPLHGR, maximum average planar heat generation rate.

Actually, the code asks more of that. A code really needs the input of average planar linear heat generation in the exhale direction, and the peak one is the MAPLHGR and that affects the PCT directly.

Okay, so when they do the calculation for a given core, given cycle, given fuel, assuming other variables are -- should be correctly, they assume the maximum possible MAPLHGR for that cycle and generate the PCT for that fuel and did the same thing assuming the maximum possible MAPLHGR for Westinghouse fuel, and that gave a higher PCT.

But in the real core, it won't be like that. It will be combined -- both fuel together and there, the data showed that the MAPLHGR value would always be less than GE fuel. And therefore, the assumption that -- when they calculated 1540 degrees Fahrenheit, the MAPLHGR never is going to reach there, in reality. It will be below, always below GE MAPLHGR. And therefore, MAPLHGR value is the limited value which we should look for.

And another information is that they do not calculate, they do not run a LOCA analysis for each reload. All they do is go and verify it that the MAPLHGR is within the limit. If the MAPLHGR is, the PCT is validated. Well, that's the process involved.

CHAIR ABDEL-KHALIK: So a LOCA analysis was really not done for the Cycle 15 core as is?

MR. RAZZAQUE: It has been validated. It has been -- by MAPLHGR.

CHAIR ABDEL-KHALIK: I understand --

MR. RAZZAQUE: Yes.

CHAIR ABDEL-KHALIK: -- the way you -- but --

MR. RAZZAQUE: Right. And --

CHAIR ABDEL-KHALIK: -- as is, would the distribution of a fuel as is --

MR. RAZZAQUE: Right, unless there is --

CHAIR ABDEL-KHALIK: -- was not actually done because it's part of a reload analysis for Cycle 15? Is that correct?

MR. RAZZAQUE: -- unless there is some change in other parameters which they will then have to redo it. But I don't know exactly when it was done. Maybe you can --

MR. BOLGER: This is Fran Bolger from GE. The way staff explained it is correct. You know, the analyses are done with full cores of the two different type, and those analyses are designed to be bounding with respect to what would occur in a next core.

MR. WALLIS: And that's done for an equilibrium core?

MR. BOLGER: That's correct.

MR. WALLIS: Now if it's done for a non-equilibrium core, now much does the PCT change? If it's done for the core evolves -- how much does the PCT change as the core evolves during a cycle? Have any idea?

MR. BOLGER: Just sort of weighing whether this is a closed session discussion or not.

CHAIR ABDEL-KHALIK: If it is, we can wait until after lunch.

MR. BOLGER: Okay. Why don't we wait.

MR. WALLIS: Postpone it. Okay, that's fine.

CHAIR ABDEL-KHALIK: Okay. I have another question. Are these two-bundle designs hydraulically matched?

MR. RAZZAQUE: The effect on LOCA is not that significant.

CHAIR ABDEL-KHALIK: Regardless, the question is are they hydraulically matched?

MR. RAZZAQUE: When originally a mixed water analysis was done -- that was done many years ago -- there have to be some pressure drop tests to make sure that the assemblies have compatible pressure drop. I think that probably would be the key parameter which will effect, but the LOCA, it really doesn't matter that much. But it does in the transient.

CHAIR ABDEL-KHALIK: Okay. Thank you.

MR. RAZZAQUE: Yes. And mixed water analysis was approved many years ago. I don't know when they first started using GE, but this one is -- we didn't' go reviewing the mixed core approval. Basically, looked at the EPU.

MEMBER BANERJEE: So the hydraulic characteristics are very similar, the fuel? I didn't get the sense of the answer.

MR. NOTIGAN: This is Don Notigan, PSEG. To support the EPU licensing, PSEG submitted on our docket a thermal-hydraulic compatibility assessment and report that has the details of how the GE methodology was utilized to analyze the thermal-hydraulic performance of the SVEA fuel. In that report, we concluded that introduction of the GE fuel at that time into the Hope Creek core, which had had SVEA-96 plus fuel in it, did not cause any change in thermal-hydraulic imbalance.

MEMBER BANERJEE: Will the fuel there, fossil or whatever it is, and the GE fuel, did they have similar thermal-hydraulic characteristics? I mean it's a straight question -- yes or no.

MR. NOTIGAN: They have similar, yes. However, the mechanical design of the assemblies are different. I have slides to illustrate the difference. And because of that difference, the active flow through the two designs are slightly different.

MEMBER BANERJEE: I think we should discuss this in closed session.

MEMBER MAYNARD: Well, don't you take a penalty in the analysis anytime you have a non-homogeneous core? I mean doesn't the analysis that you do have some penalty into it when you've got different types of fuel assemblies -- penalty?

MR. NAKANISHI: This is Tony Nakanishi with Reactor Systems. I could add that sometime ago, the licensee submitted a critical power correlation supporting the SVEA fuel, and staff reviewed that and approved that.

MEMBER BANERJEE: What about the void correlation?

MR. NAKANISHI: Again, I guess we could probably defer that to closed session.

MEMBER BANERJEE: Maybe, you know, we need to know a little more details, Said, on this.

MR. NAKANISHI: Basically --

CHAIR ABDEL-KHALIK: When we're in closed session, you can ask these detailed questions and, hopefully, both the staff and the applicant --

MEMBER BANERJEE: Hopefully, we will understand the uncertainty in the void fraction for the SVEA fuel? Do we have data?

MR. NAKANISHI: The approach that GE or the licensee is taking is they're applying their NRR methods topical which includes some of these -- accounts for these additional margins. We can discuss that more in the closed session.

MR. WALLIS: How does MAPLHGR validate a PCT?

MR. RAZZAQUE: How does it validate PCT?

MR. WALLIS: MAPLHGR has nothing to do with LOCA, does it?

MR. RAZZAQUE: Yes.

MR. WALLIS: MAPLHGR is just for the heat generation rate?

MR. RAZZAQUE: That's right and it affects the stored energy, and therefore, ultimately the PCT.

MR. WALLIS: It'S an input to a PCT calculation.

MR. RAZZAQUE: Exactly. That's --

MR. WALLIS: It doesn't validate. It's just an input to it --

MEMBER BANERJEE: It doesn't. It's an

input.

MR. WALLIS: -- if it's low enough --

MR. RAZZAQUE: The validate means that when they design the core, they calculate the MAPLHGR for that core and see whether it is less than the one which was sued to calculate the PCT. That is the validation.

MR. WALLIS: But it's not -- but more things than just MAPLHGR influence PCT --

MR. RAZZAQUE: Yes, there are many things, but the marketplace is the one --

MR. WALLIS: It's a sort of DPTC, D-MAPLHGR that you've -- someone's established so that you know how one influences the other?

MR. RAZZAQUE: Assuming the other variables --

MR. WALLIS: Maybe this can be explained in a closed session or something? I'm confused.

MR. NAKANISHI: Or I guess I could say that the baseline analysis, it will basically provide sufficient leeway for cycle-specific differences. And really, the key change from cycle to cycle is covered by MAPLHGR.

MR. WALLIS: This is part of what I was told would be answered in a closed session, is it?

MEMBER ARMIJO: Or it would be --

MR. WALLIS: I think it is.

MEMBER ARMIJO: -- or you could get it.

MR. WALLIS: I'm going to get the answer in the closed session.

CHAIR ABDEL-KHALIK: I think we'll have more leeway to ask questions and receive answers during that time.

MEMBER ARMIJO: I have maybe a very simple question. Is SAFER/GESTR approved for use on SVEA-96, or was it just an analysis that was done sort of interesting but not really an approved analysis.

MR. RAZZAQUE: The process that works is -- the way that was approved is that the -- when the GE -- you have a GE core using GE methods. Now another fuel is introduced. The -- first of all, there has to be thermal-hydraulic compatibility with those two bundles, and they have to be verified and checked. And the other is that the licensee or the vendor or both has to get enough information from the other vendor about the fuel to perform the analysis. After you get all the information that you need, which is basically the information like fuel itself, like the density, material properties, flow dimension and those kind of things, then you use your code, GE code, assuming it's like a GE bundle although the dimensions are different for every --

MEMBER BANERJEE: But here is the issue, I think which --

MEMBER ARMIJO: It's more legal.

MEMBER BANERJEE: Yes, but what Sam and I are both getting at is do we have the same database with the SVEA-96 plus fuel, and maybe you need to answer this in closed session, as we have with GE fuel? We understand GE fuel because we have dealt with this previously in approving things and so on. So we know a lot about GE fuel. Do we know the same about this Westinghouse fuel? I guess that's the issue and the uncertainties in the various critical power issues and the void fraction correlation.

MR. WALLIS: Do you use the same void fraction correlation for the two?

MR. NAKANISHI: I believe the -- and GE or licensee can correct me, but I believe that is true.

MR. WALLIS: Someone's checked that the test is valid, equally valid --

MR. NAKANISHI: I guess --

MR. WALLIS: -- or bias in one way with one fuel versus the other?

MR. NAKANISHI: A point that provides the staff additional conflict is the SVEA fuel has been exposed a few times.

MR. WALLIS: Oh, yes, that's right.

MR. NAKANISHI: And if SVEA fuel were as reactive as GE-14 fuel, for example, then we would be a lot more concerned, and we would be providing a lot more review associated with that.

MEMBER BANERJEE: If they go reload it, will there be --

MEMBER ARMIJO: Well, I don't know if the issue will come up.

MEMBER BANERJEE: Will that issue come up at that point, or how will it be handled?

MR. NAKANISHI: They did the transition, I believe, obviously, at a pre-EPU condition.

MEMBER BANERJEE: Will you feel more comfortable to answer these questions when we were in closed session?

MR. NAKANISHI: Absolutely.

MEMBER BANERJEE: Okay.

MR. WALLIS: Let's do that.

MR. RAZZAQUE: Actually, the way I understand -- licensee may correct me -- they are going to phase Westinghouse fuel out after Cycle 15, or at most 16 maybe. Is that -- Cycle 16 will still have some fuel left and then after that, no fuel?

MR. NOTIGAN: This is Don Notigan, PSEG. We are looking at the core design requirements for Cycle 16. We're starting that right now. And right now it looks like preliminary, we will not have the SVEA fuel in the next core in Cycle 16.

MR. RAZZAQUE: Basically, you're talking about half a cycle, maybe less than that.

MEMBER BONACA: And when you did LOCA analysis, what fuel did you use? Did you assume that GE fuel would be limiting and then you assumed full characteristics of the GE fuel to determine PCT? I mean this is a mixed core and I'm trying to understand how you do the thermal-hydraulic analysis, SAFER/GESTR. What kind of fuel-related parameters are you using?

MR. RAZZAQUE: Why the two separate PCT was generated -- one for GE fuel, another for the Westinghouse fuel --

MEMBER BANERJEE: Yes.

MR. RAZZAQUE: -- deeper.

MEMBER BANERJEE: But assuming separately, then first of all you have full GE fuel or full SVEA fuel?

MR. RAZZAQUE: SVEA fuel, yes. And they

have the information for SVEA fuel to use that in the code to calculate the PCT, and it turns out to be different, higher actually, if you use the same MAPLHGR.

MEMBER BANERJEE: Why is that?

MR. RAZZAQUE: That --

MEMBER BANERJEE: Well, it's --

MR. RAZZAQUE: It may be the fuel design itself basically, because the fuel itself, the thickness and the diameter and the material properties will affect. And I can see that probably would be the reason if we assumed, say, MAPLHGR and if all other inputs are the same for the vessel and the core, the geometry of the fuel probably would be the responsible for change.

MEMBER BANERJEE: But this fuel is supposed to have similar thermal-hydraulic characteristics, right?

MR. RAZZAQUE: But not necessarily material properties.

MEMBER BANERJEE: Well, is the cladding different or --

MEMBER BONACA: Well, for one, the cladding is twice-burnt or three-times burnt.

MEMBER BANERJEE: But I assume that this

number 1540 is coming when you've loaded the core with --

MR. WALLIS: It's an equilibrium core full of SVEA fuel. IT's an artificial.

MEMBER BANERJEE: So it's two artificial cases because that's not the core in -- but they should be two comparable cases, right? And two comparable cases, you're getting some difference which may not be important but it should be reconciled in some way?

MEMBER BONACA: Yes. For example, you know --

MEMBER BANERJEE: Why is different.

MEMBER BONACA: -- I look at this loading and the four assemblies in the center of the core SVEA fuels, so now, you know, my question that comes to mind is will the flow preferentially goes in the SVEA fuel versus the GE fuel? I don't know. I mean that's the kind of questions we're raising, I believe, here. And --

MR. RAZZAQUE: We reviewed --

MEMBER BONACA: -- then you have to take into account the cladding is different cladding, in this particular case, at least twice-burnt, I think. You know, here it says thrice-burnt but maybe twice-burnt as you said.

MR. WALLIS: The hot channel is GE fuel, isn't it?

MR. RAZZAQUE: Yes, correct.

MR. WALLIS: So why do a PCT with SVEA fuel?

MR. RAZZAQUE: Again, if you assume the same MAPLHGR which you are assuming is this whole bundle SVEA fuel.

CHAIR ABDEL-KHALIK: Artificial --

MR. RAZZAQUE: Artificial --

CHAIR ABDEL-KHALIK: -- cores essentially.

MR. RAZZAQUE: Basically, this is the maximum possible the SVEA can go.

MR. WALLIS: Oh, this is the maximum --

MEMBER BANERJEE: Now having done the calculation, you've raised a question that you need not have raised probably. Why is it different.

MR. RAZZAQUE: I don't know. GE can anser that, but my judgment tells me it will be -- because when they use equilibrium core, the only difference would be the information regarding the specific fuel, so my judgment will tell that that would be causing the difference.

MR. WALLIS: But it cause a difference of

600 degrees?

MR. RAZZAQUE: It should not.

MEMBER BANERJEE: It's not 600 degrees.

MR. WALLIS: Well, he said 20 to 100.

MR. RAZZAQUE: Yes. It's about 150 or 160, something like that.

CHAIR ABDEL-KHALIK: Now with both of these analyses, you have to provide input which describes the performance of the -- characteristics of the ECCS system, pump characteristics, etcetera. Now is that input based on tech specs limits? Is it based on actual historical measured performance? What did you use?

MR. RAZZAQUE: Yes. There are tech specs limits on the ECCS injection, flow rate, time, and the analysis assumes that and the limiting condition to calculate the worse scenario.

CHAIR ABDEL-KHALIK: So the same question that I asked with regard to SRV performance applies here. What is the historical performance of your ECCS system vis-a-vis the limits in tech specs?

MR. WALLIS: Historical performance?

CHAIR ABDEL-KHALIK: Right, testing.

MR. WALLIS: Has it ever had to work?

CHAIR ABDEL-KHALIK: No, no, no. I mean,

you know, testing

MR. WALLIS: Oh, testing.

MEMBER BANERJEE: Is there a way to measure it? That's the first thing.

CHAIR ABDEL-KHALIK: Do you have data to indicate that you are always in compliance with tech specs limits that are used in these analyses.

MEMBER BANERJEE: Difficult -- would have to be.

MR. DAVISON: Paul Davison. If I could just clarification on what specific requirements for ECCS are you referring to?

CHAIR ABDEL-KHALIK: Pump characteristics.

MR. DAVISON: Okay. Yes, we performed all IST testing on our RHR core spray, RCIC, HPIC pumps, all our ACCS pumps. So I do quarterly IST performance testing to verify that they're acceptable. I also trend that data. I also keep unavailability data and MSPI data on all of the safety pumps as well, safety systems as well all below -- all in top quartile performance ranges for all of our ECCS pumps. So generically, the answer is we do testing programs and we monitor per MSPI and SSPI unavailability to say our ECCS system is robust and readily available.

CHAIR ABDEL-KHALIK: So in, you know, all the previous operating history of Hope Creek, in all the surveillance testing, none of these pumps have ever fallen blow the tech specs limits?

MR. DAVISON: Not that I'm aware of but I will go verify that fact. I'm not -- that -- I do not have any data that says we've ever had a failed pump, but I will go back and verify.

CHAIR ABDEL-KHALIK: Yes, if you would verify that for us --

MR. DAVISON: Yes.

CHAIR ABDEL-KHALIK: -- I think that would be -- thank you.

MEMBER MAYNARD: I'm not sure I understand the applicability of that to EPU. That sounds like if there's any issues, that's a current operating issue. The licensees are required to operate within their tech specs. You have tech spec limits on these things. I'm struggling with tying it to EPU.

CHAIR ABDEL-KHALIK: Well, I mean if there is historical information -- there may not be, okay -- but if there is historical indication that the pump performance is consistently below tech spec limits, then these analyses are essentially meaningless.

MEMBER MAYNARD: But that would also meant that their current operating would be issues --

CHAIR ABDEL-KHALIK: Right.

MEMBER MAYNARD: -- and when that occurs, there's other regulatory mechanisms that come into play for dealing with those issues, because your tech specs, you have to comply. And being out of compliance of finding that you've been out of compliance for some time, there are regulatory processes that deal with that --

CHAIR ABDEL-KHALIK: Granted.

MEMBER MAYNARD: -- because your current analyses are based on that, too, so.

CHAIR ABDEL-KHALIK: Granted, but that would be a piece of information that would allow people to sort of put some perspective on the validity of whatever analyses have been performed.

MR. RAZZAQUE: Basically, reemphasizing our analyses, scope of the review is focused on the EPU because they already approved a license to operate at the current power level. We are not going back unless we find something -- error. We look at the extended area where they are coming into.

CHAIR ABDEL-KHALIK: Your know, again, I fully understand this, but as an engineer, you look at a number, you ask what is the error bar on this number and what are the sources of possible uncertainties in this number, and that's what I'm trying to get at.

MR. RAZZAQUE: I understand. If anymore question --

MEMBER BANERJEE: Just I hope when we come to the closed session, you explain -- it's not mission critical -- but why there is a difference in the PCTs between the GE-14 and the SVEA-96. I'm assuming that all the conditions are more or less the same, and these bundles are supposed to be thermal-hydraulically similar, so I'm still puzzled by this 160 degrees difference.

MR. RAZZAQUE: We did not specifically investigate -- spend time investigating why the difference is for several reasons. One is the result -- there is plenty of margin. Second is the SVEA will be a limiting fuel and we know that. The MAPLHGR will be way below that which are assumed. And --

CHAIR ABDEL-KHALIK: Nonetheless, it's confidence or not confidence in the methods.

MR. RAZZAQUE: For interest of knowing, yes. But the --

CHAIR ABDEL-KHALIK: I think in the closed session, perhaps GE, who did the analysis, will have more information or --

MEMBER BANERJEE: Well, I'd be interested to know also whether the staff has investigated this or not.

MR. RAZZAQUE: As I mentioned, we have not specifically on this issue.

MR. WALLIS: Staff only did calculations with the GE fuel --

MR. RAZZAQUE: No, we made sure that the calculated values are well within the limits --

MEMBER BANERJEE: But did you do confirmatory calculations?

MR. RAZZAQUE: Yes, we did.

MEMBER BANERJEE: Just with GE --

MR. RAZZAQUE: And it was bounded. The next slide is that.

MEMBER BANERJEE: Okay.

MR. RAZZAQUE: All right. If you have no more questions on this, I can move to the next one which says that RELAP5 code was used for GE-14. Again, we did not use SVEA because of the fact that SVEA would be operating at a much less MAPLHGR than GE, and therefore, it will be way below 1540. So we picked one, and GE was the one we picked.

MEMBER BONACA: Because 1540 was calculated assuming the same MAPLHGR --

MR. RAZZAQUE: That is correct.

MEMBER BONACA: -- while, in reality --

MR. RAZZAQUE: It will be --

MEMBER BONACA: -- much lower?

MR. RAZZAQUE: Exactly, because of the low power on those bundles. And Dr. Huang there, he -- you calculated using RELAP5, the GE-14, and if you have more -- you want a more --

MR. WALLIS: The value was 300 or 400 degrees higher because of radiation --

MR. RAZZAQUE: Yes. Our -- his calculation gave 1640 degrees. Okay? But that has some built in conservatism.

MR. WALLIS: And you expect it about 300 degrees higher because you've ignored radiation --

MR. RAZZAQUE: Correct.

MR. WALLIS: -- which is historically --

MR. RAZZAQUE: We have done that before, yes.

CHAIR ABDEL-KHALIK: Now tell me again, what is the sort of the logic of doing confirmatory analyses if you do them at conditions different than or using assumptions different than what the applicant is using?

MR. RAZZAQUE: Let me tell you my understanding of this. We try to -- our review, staff review, in most areas, at least what I did here was to get a reasonable assurance, not to exactly try to duplicate the licensee. First of all, it is not possible, because the cores are different, models are different, nodings are different. But we need to get some idea whether the licensee's calculations are way off or something. That is the reasonable assurance, I think, what we are trying to achieve. And one way to get the reasonable assurance would be run a code which we are comfortable with, and use some bounding type calculation. In other words, ignore radiation is one way we did, because it's more difficult to review factors and those things, hard to calculate. Sometimes we don't want to spend too much time, because we're trying to get reasonable assurance and the code is different. That is the bottom line.

MEMBER BANERJEE: You ran RELAP5 in a mode which was similar, however, with assumptions similar to the GE calculation?

MR. RAZZAQUE: Yes, except those few -- one like radiation we didn't include, because we know that will make things worse. It won't make things the other way around. Otherwise, we would have included it. And so things like that which will always make the PCT higher. That's the assumption we will make, not the other way around. And we don't want to add anything but that was the key assumption, that radiation was ignored.

MEMBER ARMIJO: If you had run RELAP5 with a SVEA fuel and you added several hundred degrees on top of, let's say, what the GE analysis came up with of 1540, you might have been on the border of 2200.

MR. RAZZAQUE: Well, if you straight take -- just as taking 1640 --

MEMBER ARMIJO: For the equilibrium.

MR. RAZZAQUE: Three hundred. Yes, at 300 degree, it will still be 18-something. Besides, we are taking 1540 for SVEA fuel which won't be happening --

MEMBER ARMIJO: Yes. It's a hypothetical --

MR. RAZZAQUE: Hypothetical.

MEMBER ARMIJO: -- doesn't exist.

MR. WALLIS: It would be very good, though, to run RELAP5 with radiation. Does this TRACE model, this phenomenon, okay? Does this scenario --

MEMBER BANERJEE: TRACE certainly runs BWR with no problem now. We just had it done.

MR. RAZZAQUE: I am not sure about TRACE will have the capability now -- do other --

MEMBER BANERJEE: We have --

MR. RAZZAQUE: We don't know --

MEMBER BANERJEE: -- runs with TRACE and FOX coupled.

MR. WALLIS: Yes. That's what should be done.

MR. WANG: This is Weldon Wang. Actually, I performed the RELAP5 calculations for this power uprate. And the flow trace -- okay, so the reason we chose RELAP5 at the time is really there is a RELAP5 deck available for the Browns Ferry, and we have verified the geometry and the dimensions of the vessel in both BWR-4 --

UNIDENTIFIED SPEAKER: For Hope Creek you mean.

MR. WANG: -- for Hope Creek, right -- compared with Browns Ferry. However, we also noticed that there are differences. For example, I believe it was a letter c injection of the front. So, we, at a certain point, we pick up a rule of five because we think that job will be minimal so we can start to run the code right away.

MR. WALLIS: I thought TRACE was supposed to accept these other decks?

MEMBER BANERJEE: But there's a TRACE deck for Browns Ferry.

MR. WALLIS: There is a TRACE deck? I thought it was supposed to take a RELAP5 and translate --

MEMBER BANERJEE: I hope you don't use RELAP5 for Browns Ferry?

MR. WALLIS: That's what he did.

MEMBER BANERJEE: It's time to move on, I think, to a better validated code.

MR. RAZZAQUE: So far, in EPUs, we've used RELAP5 before -- Vermont Yankee, Browns Ferry and --

MEMBER BANERJEE: I know -- we have. This doesn't meant you have to --

MR. RAZZAQUE: No.

MEMBER BANERJEE: -- harden --

MR. RAZZAQUE: We don't --

MR. WALLIS: It will be very interesting to see if TRACE and RELAP5 and SAFER/GESTR, with the same assumptions all the way through, how different their answers are. It would be very interesting to see rather than this conservatively-bounds sort of idea. And if they differ significantly, then we might begin to wonder why.

MEMBER BANERJEE: Well, the thing is LOCA is not really a concern in these matters.

MR. WALLIS: It doesn't seem to be.

MEMBER BANERJEE: There are other things like the anticipated transients and things which are very different where there are concerns, so --

MR. RAZZAQUE: The -- right, actually, the PCT with EPU only increased 10 degrees F for GE fuel and didn't increase at all for SVEA fuel. Again, we, sometime ago --

MR. WALLIS: What is limiting the EPU? It's not LOCA --

MR. RAZZAQUE: It looks like not LOCA. Sometimes it is maybe by a few degrees, but this time here, it is a few degrees. We have seen PCT even going down. Remember in one case, we even discussed that here.

MR. WALLIS: When the fluence goes down, all kinds of things go down. I don't know why but it does because they use it --

MR. RAZZAQUE: I thought we tried to understand that phenomena -- why it goes down, flattening affect --

MR. WALLIS: Right.

MR. RAZZAQUE: -- and redistribution of the flow and those kind of things, so. PCTs never comes out to be a very big change. I never saw more than --

MR. WALLIS: What I it that limits these EPUs?

MR. RAZZAQUE: Pardon me?

MR. WALLIS: Why don't they go to 40% instead of 15? What is it that limits EPU.

MR. RAZZAQUE: MCPR will definitely -- minimum critical power issue, LGR --

MR. WALLIS: MAPLHGR or something like that?

MR. RAZZAQUE: -- MAPLHGR, those kind of things.

MEMBER BANERJEE: It's the fuel for the --

MR. WALLIS: No. It is the CPR.

MR. RAZZAQUE: Right.

MR. WALLIS: It's not the accident, though. It's the regular --

CHAIR ABDEL-KHALIK: Please continue.

MR. RAZZAQUE: Okay. So staff calculation verified not only the PCTs boundings, we bounded the PCT basically. We didn't do exact calculations, but I here what you are saying. The other is we also confirmed the break size, the large-break LOCA -- we confirmed that, and the break-spectrum, things like that.

Next slide is on ATWS. We present the results. The top bullet represents the results, and the first two basically talk about requirements. They match the requirements, like they have to have alternate rod injection which they have installed. Boron capability is 86 gpm which they have --

MEMBER BANERJEE: Is this enriched boron?

MR. RAZZAQUE: Yes. And then they have recirc pump trip installed. So those are required by regulation, in 10 CRF 50.62. They have those. And the they rely on te EOP, of course.

MR. WALLIS: So this is to reduce water level or what?

MR. RAZZAQUE: Yes, water level basically, because the pump trip will be automatic. They can do it manually, too.

MR. WALLIS: So this is when the SLC system is incapable of meeting the peak pressure, so the relief valve opens.

MR. NAKANISHI: This is Tony Nakanishi. The initial peak pressure, ATWS pressure is not mitigated by --

MR. WALLIS: Before you use the SLC system?

MR. NAKANISHI: It's you basically only

have the pump trip.

MR. WALLIS: Oh, okay. And then this pool temperature, that must depend on how the pool temperature starts out which is a function of the time of year and things like that. So is this based on the highest pool temperature, or what is it based on?

MR. RAZZAQUE: It should be.

MR. WALLIS: Is it? If it's the average, then it's not so good, because sometimes the pool temperature is a few degrees above average.

MR. RAZZAQUE: The initial temperature -- maybe the --

MR. DENNY: This is Skip Denny of General Electric-Hitachi. The accident analysis - -ATWS accident analysis assumes a 95 degree pool temperature --

MR. WALLIS: It assumes the worse -- yes.

MR. DENNY: The worse case tech spec allowed.

MR. WALLIS: I thought it probably did. Thank you.

MR. DENNY: Also, minimum tech specs --

MR. WALLIS: Yes, so it's the worse. It's the really conservative.

MR. DENNY: Yes, sir.

MEMBER BANERJEE: It's pretty close to the limit?

MEMBER ARMIJO: Yes, but at 3 degrees, that's a sharp pencil.

MR. WALLIS: Yes, but it's very unlikely that it's going to get anywhere near that. Ninety-five degrees is a very high temperature.

CHAIR ABDEL-KHALIK: What is the basis of the 201 degree limit?

MR. DENNY: Skip Denny again, General Electric-Hitachi. There are two concerns with ATWS. One is NSPH which is a lot higher than this, 218 degrees. The 201 is based on ensuring that steam discharge from the NSRVs is fully quenched and does not potentially ingest into the ECCS suction or the suppression pool cooling lines. So it's SRV discharge temperature limiting. This is a bulk temperature limit. It maintains at 218 degrees -- local temperature at the discharge.

CHAIR ABDEL-KHALIK: Thank you.

MR. DENNY: Yes, sir.

MEMBER BANERJEE: Do you have any idea how much water there is to suppress this compared to, say, Vermont Yankee or Browns Ferry or per megawatt let's put it. Is it --

MR. WALLIS: About one cubic meter per megawatt.

MEMBER BANERJEE: Well, is it about the same or is it very different?

MR. DENNY: The ATWS analysis for Hope Creek assumes the tech specs limit --

MEMBER BANERJEE: No, no, no. I'm just asking a general question. How much water is there in the suppression pool?

CHAIR ABDEL-KHALIK: We asked that question earlier.

MEMBER BANERJEE: Oh, you did? Okay. What did --

CHAIR ABDEL-KHALIK: A hundred and eighteen thousand cubic feet minimum.

MR. DUKE: This is Paul Duke, PSEG. The volumes in plants of similar rating such as Peach Bottom and Browns Ferry is similar.

MR. DEVINE: Similar to Vermont Yankee, too?

MR. DUKE: No, similar to Hope Creek. I can't tell you the volume of VY but for Browns Ferry, it's a similar volume with a similar rating.

MEMBER BANERJEE: But the rating is lower?

MEMBER BANERJEE: But rating is lower,

right.

MEMBER BONACA: That's why you see some plants that have a problem with the backpressure and others don't.

CHAIR ABDEL-KHALIK: Please continue.

MR. RAZZAQUE: The last slide is my conclusion which is basically repeating again that the guidelines were followed, generic evaluations were used which were previously approved. And our review basically focused on the effect of EPU on the current licensing basis, not necessarily to go back beyond unless we come up with some problem.

MR. NAKANISHI: Should I keep going?

CHAIR ABDEL-KHALIK: No. What I would like to do is break for lunch for one hour. We'll be back here at 1:00 o'clock. AT that time, both the staff's presentation and the applicant's presentation on fuel methods will be done in a closed session.

MEMBER BANERJEE: So you get ride of this open session matter?

CHAIR ABDEL-KHALIK: Right. Item 8 on the agenda will now be moved into a closed session so that you can ask whatever question you would like of the staff, and we will reconvene at 1:00 o'clock.

(Whereupon, open session of the foregoing matter adjourned at 11:52 a.m. for a luncheon break and holding of closed session.)

(Whereupon, at 2:24 p.m., open session in the foregoing matter is resumed.)

CHAIR ABDEL-KHALIK: We're back in session. Before we start on item 12 on the agenda, there's a question regarding the standby liquid system operation -- liquid control system operation that Mr. Maynard has.

MEMBER MAYNARD: I hate to take a step back, but we discussed this in a couple of different sessions, and I'd like to pull it together. Under the ATWS scenario, the peak pressure occurs before the automatic implementation of the SLC system. However, that peak pressure is higher than what the relief valves for the SLC system. The operators talk about that they're trained to go ahead an initiate that before the automatic, so it's very possible that they would be initiating that at a time when the pressure is higher than the relief valve standpoint.

You've mentioned something about that's okay because there's plenty of margin. I guess I'd like to explore that margin and why it's okay to do it at that time and lift the relief valves?

MR. DelGAIZO: Okay. I'm Ted DelGaizo.

Because there's actually a regulatory requirement. I think it's 100 pounds. It could even be 150. But there's a requirement on the pressure that you'll be when you credit SLC for injecting and the reset of that relief valve. You're right, it is 1400 and it resets somewhat below that. Not much. But we meet that regulatory requirement which, again, I think is 100 psid, so that we're at least 100 pounds down below that reset point at the time that the analysis shows like it's going to inject. And the reason for that big margin or that requirement for the delta P is specifically so that if it does lift, it's assured to recede and not be close to the reset point.

MEMBER MAYNARD: And during that time that it has lifted, you're not losing more born than what you need to be able to --

MR. DelGAIZO: Oh, no, we're not losing any boron. It's recirculating.

MEMBER MAYNARD: It's recirculating.

MR. DelGAIZO: Right. So the boron is just fine. What you have to be sure of is when the time comes that the boron needs to go in, the relief valve is reset.

MEMBER MAYNARD: Okay, fine. That answers my questions.

CHAIR ABDEL-KHALIK: Okay. Let's proceed with the presentation then.

MR. DAVISON: Okay. Good afternoon. I'm Paul Davison, again. And next to me to discuss the containment analysis methodology and response is Mr. Ted DelGaizo frm Mainline Engineering as well as Mr. Skip Denny from General Electric-Hitachi.

For background, this is a simplified depiction of the Hope Creek reactor building and containment structure. Again, Hope Creek has that Mark I containment as evidenced by the inverted lightbulb shape and the attached torus which we also refer to as the suppression pool. The drywell is a steel pressure vessel which is encased in concrete, and the torus is connected to the drywell airspace via 8 vent pipes. The vent pipes are connected to a header that distributes the flow to the downcomers which terminate approximately 3 feet under the tech specs minimum required water level.

On the next slide -- get into the actual containment response analysis being performed using the NRC-approved General Electric methodology. The results indicate that adequate margin do exist for design basis accident conditions. Specifically, on the codes, LAMB, M3CPT and SuperHEX were the primary codes utilized for EPU.

CHAIR ABDEL-KHALIK: Now M3CPT was developed for Mark III containment analysis. The question is were there any modifications to either the code or to the input required to apply to the Mark I containment of Hope Creek?

MR. DENNY: This is Skip Denny of General Electric-Hitachi. No, sir, there's no need to modify the code itself. The code allows for three levels of relief vent pipes basically and whether they go horizontal or vertical. And so the inputs would be set up for a Mark I containment to utilize just one of those vent pipes allowed in the code itself. So the code is, although designed particularly for the Mark III containment, it handles all three containment types, Mark I, II and III.

CHAIR ABDEL-KHALIK: Okay. The other question is that SuperHEX has never really been reviewed by the staff, and I understand this is one of the codes that's been used for many, many years, and it's -- the question then is what type of confirmatory analyses have been done by the staff to confirm the results of these analyses?

MR. LAMB: This is John Lamb with the NRC. Because we're running a little early, our containment expert should be coming shortly, so he'll be able to answer those questions.

CHAIR ABDEL-KHALIK: All right.

MEMBER BONACA: I have also a question regarding are these codes also the same used for the analysis until now, or did you have some changes either in the codes or inputs? I know you made the change, for example, to the decay heat that you use for the long-term. Could you identify what changes you had in the methodologies used to address the power uprate?

MR. DENNY: Yes, sir. Skip Denny again. M3CPT is the code of record for Hope Creek. M3CPT has a vessel model internal to it, and the current short-term analysis for Hope Creek uses the vessel model internal to M3CPT. However, we now typically use a LAMB code because its vessel model is more elaborate than what's internal to M3CPT. And so with this, we are using a LAMB blowdown particularly. And that M3CPT will read LAMB blowdown directly.

MEMBER BONACA: So I guess LAMB kind of sharpens the pencil somewhat?

MR. DENNY: A little bit. LAMB is particularly useful because it can handle off-rated conditions whereas M3CPT can't. LAMB has a highly nodalized vessel model whereas M3CPT is basically a tin can vessel model.

MEMBER BONACA: No. I guess by reading the results, etcetera, clearly, I see acceptable results. I was wondering of what the affect of the power uprate really was analytically in values, and I couldn't really see that because, I mean, you may have more changes to the assumptions, for example, again, the decay heat that you used to perform the long-term containment analysis?

MR. DENNY: One of the slides that we're going to be showing you is going to be exactly that.

MR. DAVISON: In two slides, we'll get the actual table where we compare our current methodology with the new methodology at our current licensed thermal power and then taking that to the EPU as well.

MEMBER BONACA: Okay. So we can understand what the effect really will be so far as a delta, although I understand that if you sharpen your pencil, you get within the limits. Okay. Very good.

MEMBER BANERJEE: So has LAMB been approved for use now by the staff?

MR. DENNY: This is not the first time we brought LAMB.

MEMBER BANERJEE: No, that's not -- has it been approved?

MR. DENNY: LAMB has been approved for LOCA for many, many years.

MEMBER BANERJEE: Has been approved?

MR. DENNY: Approved.

MEMBER BANERJEE: Not just brought forward and accepted? Is that correct, LAMB has been approved for use?

MR. LAMB: I'm not sure. This is John Lamb.

MEMBER BANERJEE: So it has been used for LOCA before?

MR. LAMB: My understanding, yes, it's been used before, but I'm not an expert in this area, so Rich Lobel should be here shortly.

MEMBER BANERJEE: I guess Fran's going to tell us.

MR. BOLGER: This is Fran Bolger. The LAMB is an integral part of the SAFER/GESTR LOCA methodology, and it is approved.

MEMBER BANERJEE: So it is approved.

CHAIR ABDEL-KHALIK: But is it a correct statement that I made earlier that SuperHEX has never been evaluated by the staff?

MR. BOLGER: Well, I think staff may have some comments on their benchmarking that they have done with the SuperHEX when they get here.

CHAIR ABDEL-KHALIK: Okay. Thank you.

MEMBER BANERJEE: So LAMB has been approved in the SAFER/GESTR context. Has it been approved -- Fran, don't run away -- has it been approved in the containment context?

MR. BOLGER: This is Fran Bolger again. As far as being separately reviewed and approved, I don't really know. It has been presented in many power uprates as part of the power uprate methodology. And I believe it also is included in the ELTR and LTRs that support power uprate.

MEMBER BANERJEE: Okay.

MR. WALLIS: This is a critical flow?

CHAIR ABDEL-KHALIK: Initial period of LOCA -- blowdown period.

MR. DUKE: This is Paul Duke. We used LAMB for ARTS/MELLLA implementation to calculate blowdown flows for anulus pressurization and that was part of the application. And I believe

MR. JOYCE: he staff reviewed that in particular for anulus pressurization as part of the ARTS/MELLLA amendment that was approved a few years ago.

MR. WALLIS: What do the letters stand for in LAMB? It might tell us something about what's in it.

CHAIR ABDEL-KHALIK: Please proceed.

MR. DAVISON: Going back to the slide, the short-term analysis is dominated by the initial blowdown flow rate and that results in a minimal change due to the constant pressure nature of our power uprate condition. The long-term response was impacted due to the increase in the decay heat associated with the EPU and it results in 11.3 degree Fahrenheit increase in peak bulk suppression pool temperature.

MR. WALLIS: There was some flow rate that changed. I was surprised. What is -- where is -- the sump pipe is bigger or something? I've lost it then. I've seen no change in any of the blowdown flow rates? I thought there was a 15% change in something, but I lost --

MR. DENNY: There is a small increase in the blowdown from current licensed power to EPU power using LAMB, and you'll see that in the table that we show you, a slight increase in containment pressure as a result.

MR. WALLIS: Maybe I'll be able to find

it. I was surprised to read it somewhere in the SER. But anyway, don't worry about it.

CHAIR ABDEL-KHALIK: And that slight increase in blowdown flow is a result of what, even though you're essentially at constant pressure?

MR. DAVISON: It's driving it, yes.

MEMBER BANERJEE: Well, you have more stored energy in the core.

MR. DENNY: Yes. I believe it has to do with more stored energy in the vessel liquid. It happens around 10 seconds where the blowdown diverges a little bit from current power to EPU power, and that's what's giving us a slight increase in drywell pressure. But it's basically that the flow rate is decreasing as reactor pressure is decreasing, but with LAMB, at EPU conditions, it doesn't drop off as fast.

CHAIR ABDEL-KHALIK: Okay. I think I understand. More stored energy essentially in the inventory within the vessel because your feedwater temperature is slightly higher, the core temperature is slightly higher, all that stuff. Okay.

MEMBER BANERJEE: The average void fraction is higher.

MR. DelGAIZO: We also have a little higher DP. In other words, the dome pressure is constant. The DP in the vessel increases slightly due to the increased feed flow and the recirc and everything and the big break is the suction line break, so it could be a slightly higher pressure there, too, even though the dome pressure is a constant.

CHAIR ABDEL-KHALIK: Okay.

MR. DAVISON: All right. On slide 45, the DBA LOCA containment analysis was performed at 102% of the 3840 megawatt thermal rating. For the analysis, the ANSI/ANS 5.1 methodology was -- uncertainty was utilized for the extended power uprate licensed topical report. This approach provides a more realistic containment temperature response and differs from the current Hope Creek UFSAR analysis based on the previous made with decay heat methodology. We'll actually look at those in tabular form in the next page.

The analysis did credit passive heat sinks including the drywell metal inner shell. The containment vent system, metal piping and the torus metal shell. These heat sinks are not credited in the current Hope Creek UFSAR analysis, contribute to approximately 2 degrees Fahrenheit decrease in the peak bulk suppression pool water temperature.

MEMBER BONACA: Passive heat sink.

MR. DAVISON: Correct.

MEMBER BONACA: What about your decay heat curve after you complete it?

MR. DAVISON: Yes, next slide. I think that's seven, right? I think it's approximately 7 degrees -- 11 total, right.

MEMBER BONACA: It's above 10 degrees coming from changes in methodology -- inputs.

MR. DAVISON: Okay. The table displays the peak drywell air --

CHAIR ABDEL-KHALIK: Back to this passive heat sink is credited in long-term analysis, this was not done in the original analysis?

MR. DAVISON: That's correct.

MR. DENNY: No, sir.

CHAIR ABDEL-KHALIK: Okay. Even though it is an option that's available in the code, so --

MR. DENNY: There were no changes in the code that would account for this.

CHAIR ABDEL-KHALIK: Thanks.

MR. DAVISON: Here's the table we referred to a few slides back. It displays the peak drywell air space pressure and temperature, the peak bulk suppression pool water temperature and the peak wet well airspace pressure and temperatures as compared between current licensed thermal power, EPU, and the design limits. So the first two columns specifically under the CLTP 3339 megawatt thermal compares the current UFSAR analysis methodology with the new EPU method results. The most notable change is the 9-degree reduction in the peak bulk suppression pool water temperature. This reveals the more realistic results associated with the transition of methodologies from MWt to the ANS 5.1 and the addition of the passive heat sinks per SuperHEX.

The results using the EPU methodology for the uprate, 3840 megawatts thermal, which is the next column over -- this result showed that the margin exists in the containment structural code and the net positive suction head design limits. Therefore, the design basis accident LOCA containment performance has margin for all parameters at the EPU conditions.

CHAIR ABDEL-KHALIK: Now let's look at the 218 degrees F entry. This value was originally 212, is that correct?

MR. DAVISON: Yes.

MR. DAVISON: Okay. Now what design changes were made to increase that design limit to 218 degrees F?

MR. DAVISON: There were no design changes.

CHAIR ABDEL-KHALIK: So how is that design limit increased to 218 degrees F from its original value of 212?

MR. DelGAIZO: This is Ted DelGaizo. We have calculations on both RHR and core spray thermal-hydraulic calculations in computer codes. They're pretty detailed. And out of those calculations come the NSPH calculation. What we did is in order to bound the higher numbers that we were getting for EPU -- and in fact, when we first started this project and we looked at 120%, they were even a little bit higher -- I think 215 might have been the max -- so we picked a number that would bound all possible suppression pool temperatures and did the NSPH calculation with that assumption. So it's an assumed value, 218.

Now in addition to assuming that, we had to do some other things. We had to check the seals on the core spray pump and make sure they could handle 218. There were some other things that were done, but basically, in order to change that to our new so-called design limit for suppression pool temperature, we ran the NSPH calculations to show we had margins with atmospheric in the containment, no overpressure, 218 F, and we showed that we had sufficient --

MR. WALLIS: And this works because the pumps are located way --

MR. DelGAIZO: Right, our pumps -- we really have a great configuration.

MR. WALLIS: They're low down and --

MR. DelGAIZO: Right. The --

MR. DAVISON: They're vertical pumps. Our minimum suppression pool water is 71-foot elevation in the plant. Our pumps are located on 54 and they drop down 15 feet.

MR. WALLIS: Oh, they're those long tubular-type pumps --

MR. DAVISON: Yes. Multiple stages.

CHAIR ABDEL-KHALIK: So what is the elevation difference between the pump inlet port center line and the minimum water level in the suppression pool?

MR. DelGAIZO: The inlet center line is 55-1/2 feet -- 55.6 roughly. The pool minimum is 71 feet and a half inch or -- it's basically 71 feet to 55-1/2, so I guess that's 16 feet. And as pointed out, that's the pump's suction line. The impeller is about another 16 feet down below that. And we don't credit that. We went from the 71 to the 55, and that's the elevation that had to be used in the calculation. And we had 14.7 psia and the head loss through the strainers and the friction losses through the piping, we ended up with NSPH margin above the required. And the required number we used is the highest number the vendor tested. So in other words, it basically is runout flow for the required -- NSPH required, and it's actual flow for NSPH available based on the computer code.

MEMBER BONACA: So let me just -- to complete my question and that was if I assume the same computer code used before, the same inputs as before, there would be an increase in bulk pool temperature of about 10 degrees Fahrenheit? I'm trying to understand the contribution of the decay heat curve and the passive heat sink credit.

MR. DelGAIZO: Well, the way I see that -- if you notice on this slide, under the CPPU method, we actually have an 11 degree increase from the 201 to the 212. Two of that is associated with the passive heat sinks. I would say the other 9 is the decay heat.

MEMBER BONACA: Okay. So the EPU 2840 would have been assuming the same conditions --

MR. DelGAIZO: Right.

MR. DENNY: Two degrees in there for passive heat sinks.

MR. DelGAIZO: Oh, it did?

MR. DENNY: I'm sorry.

MR. DelGAIZO: Yes, you're right.

MR. DENNY: Apologize. There's a little correction. In the CLTP going from 210 to 201, that included both changing from MWt to the ANS 5.1 which gives you 7 degrees, and then the passive heat sinks give you another 2 degrees, so that totals 9 degrees decrease. The change from 201 to 212 is using the same exact methodology but increasing core power. That's giving you the actual EPU change.

MEMBER BONACA: All right. So where you have the list of EPU method is really same power level but taking credit for those things.

MR. DENNY: Correct.

MEMBER BONACA: I understand now the table. These are the answer I needed.

CHAIR ABDEL-KHALIK: I'm trying to reconcile the first two entries in the second column. How can the new method predict a lower pressure while predicting a higher temperature?

MR. DENNY: Yes, sir. I looked at that also. The lower pressure occurs because the LAMB blowdown versus M3CPT blowdown -- M3CPT doesn't have the elaborate nodalization, so the blowdown early in the event is more restrictive in LAMB than it would be in M3CPT. So the M3CPT gave you a higher peak pressure early in the event. In LAMB, it actually goes out a little bit further, so the peak pressure you see, 48.1, and its temperature is happening around a 4-second for an M3CPT alone analysis.

MR. WALLIS: So there's more gas in there? Is that it?

MR. DENNY: It's the resistance due to the recirc lines. M3CPT doesn't have --

MR. WALLIS: I take it the partial pressure of the non-condensables is bigger earlier? Is that what it is that makes it -- presumably, this pressure -- the saturation pressure of the steam plus the non-condensables, that's the problem you have, is that?

MR. DENNY: Yes.

CHAIR ABDEL-KHALIK: Yes.

MR. WALLIS: Do you have the steam tables here?

CHAIR ABDEL-KHALIK: I do have a steam table but the question is, you know, what is the contribution of the non-condensable gas to this calculated pressure of 47.6?

MR. DENNY: They both have the same initial containment pressures and temperatures.

CHAIR ABDEL-KHALIK: But the contribution of the non-condensable, if you were calculating a higher temperature, will be higher in the second calculation, right?

MR. DENNY: Non-condensable gas gets transferred to the suppression pool really quickly, so -- I guess I'm not sure I understand the question. The non-condensable gas is in the suppression pool.

MEMBER BANERJEE: I guess what would be interesting is to look at the time at which these peaks happen, because they are probably not coincidence.

MR. DENNY: Exactly. In the UFSAR method, you see that peak pressure at the roughly 4.4 seconds.

CHAIR ABDEL-KHALIK: If you have the plots, I think that would be very helpful.

MEMBER BANERJEE: That would be help -- I think that would explain it.

MR. WALLIS: Well, it's apparently at 295 -- pressure is 62 psia, so it's almost all steam in the EPU method.

MR. DENNY: Yes, sir.

MR. WALLIS: And there must be some notes on gas and available at the other -- and then the UFSAR method.

MR. DENNY: This is showing the peak pressure. As the drywell pressure --this is with LAMB blowdown -- the drywell pressure rises and continues to rise, and it goes to a little dip and peaks at about 10 seconds. The FSAR figure which is what the 48.1 which uses only M3CPT blowdown comes up really quick, peaks at about 4.5 seconds and then comes back down and actually stops dropping. It shows it's allowing a lot of energy out a lot earlier than what LAMB does, because LAMB restricts that blowdown a little bit more due to the nodalization. When fluid leaves the recirc line, fluid has to be made up from the vessel. For M3CPT, that vessel makeup is almost instantaneous, so you get a lot fast blowdown with the M3CPT model.

MR. WALLIS: Well, it has to do with the sweeping out of non-condensables, and the partial pressure of the non-condensables, presumably plus the vapor pressure of the steam, equals the pressure you get.

MR. DENNY: Yes, sir.

MR. WALLIS: And we're just saying that

from the steam tables, the EPU method corresponds almost exactly to pure steam. That's because it's later in the process.

MR. DENNY: Exactly.

MR. WALLIS: And LAMB does a good job of modeling the non-condensables sweep power? That's -- that depends upon the mixing model which often isn't all that good.

MR. DENNY: LAMB is not doing anything with containment. It's just a vessel blowdown.

MR. WALLIS: I'm sorry.

MR. DENNY: The M3CPT is --

MR. WALLIS: It's the other one that's doing the vessel. But this is assuming a mixed containment? What does it assume about that?

MR. DENNY: It assumes -- it follows the air blowing out in the --

MR. WALLIS: So there's a well-mixed containment?

MR. DENNY: --suppression pool itself. Initially, yes, sir. Basically, I guess, the conclusion is the -- because of the LAMB -- the M3CPT blowdown, the non-condensables get swept into the suppression pool a lot faster.

MR. WALLIS: Okay.

CHAIR ABDEL-KHALIK: But if it is a well-mixed containment, how can there be a zero contribution to the total pressure from the non-condensable gas at any power?

MR. DENNY: Because it's swept. It gets swept out. Even with the mixed containment, it gets swept out.

MR. WALLIS: It would be nice if you could show the non-condensable contribution here somehow, but -- do you have another plot that shows that?

MR. DAVISON: No.

MR. DENNY: I don't know if we have vent flows. No.

MR. WALLIS: That's a sort of reality check is to look at that.

MR. DENNY: I can look and see if we have vent flows where it would show air flow --

MR. WALLIS: Right.

MR. DENNY: -- and air drops off quickly.

MR. WALLIS: Maybe you can bring that tomorrow or something.

MEMBER MAYNARD: Are these numbers in your table? For the 3840, is that actually 3840 or is it 3952? The chart says 3952 and you earlier said that you did the analysis basically at the 120 --

MR. DENNY: I'm sorry. You're talking about power. I'm trying to figure out what numbers you were looking at.

MEMBER MAYNARD: This chart says 3952 and it looks like it would peak at -- looks like about 50.6. I see about 50.6 here.

MR. DelGAIZO: You know, I think all these values except the pool are 3952. I think the problem is here that --

MR. DENNY: Right. The short-term analysis was done at 102% of 120% uprate.

MEMBER MAYNARD: Okay.

MR. DENNY: Yes, sir.

MR. DelGAIZO: The number that is done at 102% of 3840 are those suppression pool temperatures which were redone to check 3840. The others were left alone because they were fine.

MEMBER MAYNARD: Okay.

CHAIR ABDEL-KHALIK: Can we go back to the table and clarify this?

MR. DelGAIZO: I'm saying I think if you -- I think the words on this were that the 3840 column is 3840 or greater, and the one that is actual 3840 is suppression pool temperature. The others are 3952. And that's why it is include --

MR. DENNY: Air pressure would also be the long-term analysis.

MR. DelGAIZO: Okay. The same for both of those.

CHAIR ABDEL-KHALIK: So could you please clarify which of the entries in the fourth column correspond to what power level?

MR. DelGAIZO: Paul, do you have Table 4-1 there from the PUSAR? My understanding is that of the -- the only row that is -- 3840 is suppression pool temperature, but I could be wrong. That's why I'd like to check on it.

MR. DENNY: Suppression pool temperature is this one here.

MR. DelGAIZO: Right.

MR. DENNY: Bulk pool temperature --

MR. DelGAIZO: Peak, right -- bulk --

MR. DENNY: -- peak wet well pressure --

MR. DelGAIZO: Right.

MR. DENNY: -- and peak wet well temperature would all be from the long term analysis, the SuperHEX. That's at 102% of 3840. That's the bottom three rows is 102% for EPU, 102% of 3840. The upper two rows, the 50.6 and the 298, that was done at 102% of 120% uprate.

CHAIR ABDEL-KHALIK: Does that answer your question, Otto?

MEMBER MAYNARD: Yes.

MR. DUKE: This is Paul Duke. The only value that we're reporting based on the 3840 is the suppression pool temperature.

MR. DENNY: I'm sorry.

CHAIR ABDEL-KHALIK: So for the record, could you please state where these entries correspond to?

MR. DUKE: The CPPU analysis is based on 102% of 3952 megawatts with the exception of the bulk suppression pool temperature, which is based on 102% of 3840 megawatts.

CHAIR ABDEL-KHALIK: Thank you.

(Off the record comments.)

MR. DAVISON: Okay?

CHAIR ABDEL-KHALIK: So back to the table, I mean I understand conceptually how you can have a temperature limit of 218 degrees F because of the elevation difference. But somehow it doesn't make sene to have a temperature limit greater than the saturation temperature of the pool when you're saying that you're utilizing that limit corresponding to a containment pressure of one atmosphere.

MR. DelGAIZO: Well, but that's the artificiality we're driven to by the reg guide. I mean I agree. The reg guide forces us to assume 14.7. We agree that at 218, we have to be higher than 14.7. In fact, if we even took that up to saturation pressure, we'd do wonderfully on margin. So it is very conservative to do --

MR. WALLIS: In regulatory space, you can violate the laws of physics if you want to.

CHAIR ABDEL-KHALIK: Well, thank you. Please continue.

MR. DAVISON: That really covered what's on page 47 when you take in that 218 and the 14.7 psia into account. The minimum net positive suction head margin availability is conservatively determined to be 1.7 feet for our residual heat removal pumps and 1.2 feet for the core spray pumps. Therefore, the ECCS net positive suction head is provided without crediting containment overpressure.

And the final slide, 48, this part of the EPU, non-LOCA events were also analyzed. There was a request for information regarding our Appendix R, and the following information is provided. This table displays the peak drywell airspace pressure, peak drywell airspace temperature and the peak bulk suppression pool temperature is compared between CLTP, EPU, and the design limits for the limiting Appendix R event. The parameters are not significantly impacted by the Appendix R event, the EPU power conditions, and significant margin continues to exist respective to the containment design analysis limits.

CHAIR ABDEL-KHALIK: Could you qualitatively explain where the Appendix R limiting scenario is?

MR. DAVISON: Let's see, Bill do you have that in your notes? Shelly? From the remote shutdown panel, right, RCIC is -- there's fire, scram, SRV opening, remote shutdown panel. RCIC has to be placed in service within 10 minutes, and suppression pool cooling is placed in service within 20 minutes which was previously time-validated by operations. The scenario and the actions that come out of that is our most limited.

CHAIR ABDEL-KHALIK: Okay. Thank you.

MR. DAVISON: And that ends the containment response session. Any additional questions?

CHAIR ABDEL-KHALIK: I guess the question was raised earlier as to what independent calculations, if any, the staff has performed in support of the calculations presented by the applicant with regard to containment response.

MR. LOBEL: Excuse me, this is Richard Lobel. The staff didn't perform any independent calculations for Hope Creek. The staff has previously performed independent calculations. We did some for Duane Arnold a long time ago comparing our code CONTAIN. I think we used -- if I remember right, we used CONTAIN. It was either CONTAIN or MELCOR we used to compare it with SuperHEX. And more recently, we did mass and energy, independent mass and energy release and containment calculations for the Vermont Yankee power uprate and the agreement for both was very good.

The mass and energy calculations calculated by Vermont Yankee were conservative compared to the staff calculations that we did we RELAP. So we didn't feel it was necessary to do independent calculations for another BWR core basically the same type of design using the same -- comparing the same codes again. So we didn't do any independent calculations for Hope Creek.

CHAIR ABDEL-KHALIK: So it was the same suite of three codes used by Vermont Yankee?

MR. LOBEL: Yes.

MR. WALLIS: I'm surprised you didn't do any calculations. I mean here Said and I are doing a hand calculation on the vapor pressure and the gas pressure and so on to check that it makes sense. Don't you do that routinely, I mean look at numbers and say do they make sense physically? I would think you'd always do that.

MR. LOBEL: Well, we do that kind of thing. I was speaking to more formal calculations with computer codes.

MR. WALLIS: Well, but the hand calculations might be more believable in some context than the computer calculations.

MR. LOBEL: Well, that's part of the review to -- I mean that's a major part of the review to look at the number and see that the numbers make sense.

MR. WALLIS: Yes. And you make calculations, too, don't you? Yes.

MR. LOBEL: The timing of the -- well, and we also not only within a given submittal, but we have the benefit of previous calculations from other licensees so we can compare things.

MR. WALLIS: Well, when they say that the heat capacity of the metal and the torus brings down the temperature by a certain amount, you can easily check that yourself and see is that reasonable.

MR. LOBEL: Sure.

MR. WALLIS: And do they make an error of a factor of 10 or something. I would hope you guys do that sort of thing.

MR. LOBEL: We do that sort of thing and like I was going to say, we also compare calculations between different submittals to see that, between submittals, that if there is a difference in a number, to try to explain the difference in terms of size of vessel, size of containment, amount of water, different technical specification limits and that kind of thing. That's a big part of the review.

MR. WALLIS: Right.

MR. DelGAIZO: Sir, I would like to say also -- this is Ted DelGaizo -- that we got our eyes on that very subject which had to do with previous margins we had shown on MPSH and the margins we were showing here, and the staff made a nice catch on where there were some disconnects which we explained that did make sense actually when we dug into. So I think there's no question they look pretty hard at MPSH from our standpoint.

MR. LOBEL: I understand there was a

question, too, about the LAMB code? Is there a question?

MR. WALLIS: Oh, what's it based on? What model does -- critical flow.

MR. LOBEL: Well, I think the GE people could do a better job than I can, but it's essentially, as I understand it, an ECCS code.

MR. WALLIS: It's a MUDI model for critical flow?

MR. LOBEL: I believe so, yes, MUDI SLP model for critical flow.

MR. DENNY: LAMB has both MUDI SLP and a homogeneous equilibrium. And for Hope Creek, we used homogeneous equilibrium.

CHAIR ABDEL-KHALIK: Is that conservative?

MR. DENNY: It is --

MR. LOBEL: It is in terms of mass flow.

MEMBER BANERJEE: It gives you a lower sump speed.

CHAIR ABDEL-KHALIK: So it is not conservative.

MR. DENNY: No, it is conservative. It is not as conservative -- SLP would give you a higher blowdown, yes. But is the licensing basis blowdown method. Now the M3CPT UFSAR one that you have here from their table, URSAR one was M3CPT with homogeneous equilibrium. Now we use LAMB with homogeneous equilibrium.

CHAIR ABDEL-KHALIK: Would the staff care to comment about the appropriateness of using a homogeneous equilibrium model for the blowdown phase of the LOCA with regard to containment analysis.

MR. LOBEL: There was a staff evaluation of a GE topical report using the homogeneous equilibrium model that was done a long time ago. I can't remember the date. And the staff concluded that using the HEM was acceptable and conservative, not because of the homogeneous equilibrium model itself but because of the GE modeling that went along with it resulted in a conservative calculation. And I don't remember offhand what the details were, but it was a staff evaluation of a GE topical report. I can get the number of the topical report. I don't remember offhand what -- why the conclusion was what it was, but I remember it had to do with the GE modeling.

MR. BOLGER: This is Fran Bolger. You know, the standard review plan for mass-energy release requires that the blowdown had to be conservative relative to data. The homogeneous equilibrium model as it applied includes a multiplier in the sump-cooled region, and that multiplier will yield blowdown rates which are conservative.

MEMBER BANERJEE: The multiplier if you're in sump-cooled blowdown. It's not sort of like a Fauske multiplier, something like that? What do you have there?

MR. BOLGER: I don't have the details on how the multiplier was derived.

MEMBER BANERJEE: Anyway, whatever the multiplier is, certainly it will be okay. It won't be conservative in the sump-cooled range. It can just be sort of a curve-fit to date probably and there are various models. But in the two-phase region, I don't see that saturate agreeing that it would be conservative?

MR. WALLIS: So the bigger the pipe the closer you get to homogeneous, don't you --

MEMBER BANERJEE: And the longer the pipe.

MR. WALLIS: - and the more weaker is very close to homogeneous.

MEMBER BANERJEE: Yes, if you have a long and big pipe, it's pretty close, but it depends on the scenario I suppose. Short pipes, you're not homogeneous.

MR. WALLIS: But it's been approved by the

NRC so --

MR. LOBEL: If I remember the --

MEMBER BANERJEE: Against the laws of physics. That's what you said --

MR. LOBEL: -- if I remember the topical report, the analysis was for long pipes. It wasn't just modeling a nozzle. It was modeling flow through the pipe --

MEMBER BANERJEE: Yes. If it's a long pipe, it'll be pretty good.

CHAIR ABDEL-KHALIK: We would appreciate that reference.

MR. LOBEL: Okay.

CHAIR ABDEL-KHALIK: Please continue.

MR. DAVISON: That was the end of the containment analysis actually.

CHAIR ABDEL-KHALIK: We'll continue with the next presentation.

MR. DAVISON: Thank you, gentlemen. That takes us to slide 50, start with the FAC presentation. Hope Creek's FAC program was developed in accordance with the industry standard from the NRC Generic Letter 89-08 requirements and, of course, the EPRI Guidance. In 2006, the bases document was updated to include the system's susceptibility evaluations including the wear associated with both single- and two-phase flow. The susceptible non-modeled analysis captures piping not suitably modeled due to uncertainty of the operating conditions or the actual small-bore pipe configurations themselves. The non-modeled analysis is used to prioritize inspections and proactive replacement of the piping with non-susceptible materials.

CHECWORKS, which Hope Creek has used since Refuel Outage Number 6 was upgraded in 2007 to the latest version and reflects the targeted power uprate for 111.5% conditions. The living program consistent of the predictive software and inspection results trending and the operating experience ensures that our inspections and replacement strategy --

MR. WALLIS: Now as I understand CHECWORKS, it sort of evolves. You get it and then as you get experience, you change the way it predicts what's going to happen. And so it's very plant specific.

MR. DAVISON: That is correct.

MR. WALLIS: And so when it says predictive analysis here, it's really -- a lot of it is based on your operating experience and inspection and so on that gives it a much more realistic predictive capability?

MR. DAVISON: That's essentially customized to the actual station and then we continue to factor in --

MR. WALLIS: The more years you've been using it, the better it should be?

MR. DAVISON: Correct. That is correct.

CHAIR ABDEL-KHALIK: Did I hear you correctly saying that this has been essentially extrapolated to the 11.5% power increase?

MR. DAVISON: Yes. So what we actually did was we -- knowing that this cycle will be running at 111.5%, we actually put it in for the full cycle. We updated the model and then we went forward to look to see if there is any earlier inspections -- or excuse me -- later inspections in subsequent refuel outages that because of the uprate would need to be done earlier. So we actually plugged it in early, did all of our extrapolations to determine if there were things we needed to do ahead of time, our last refuel outage in other words.

CHAIR ABDEL-KHALIK: How do you correct for the fact that you are going to be operating part of the cycle at the current licensing thermal power and part of the cycle at the elevated power in trends

--

MR. DAVISON: We put 111.5 for the whole cycle.

CHAIR ABDEL-KHALIK: Okay.

MR. DAVISON: We increased the wear rate.

CHAIR ABDEL-KHALIK: But if you're trying to learn from this model to be able to extrapolate, you ought to be able to extrapolate correctly.

MR. DAVISON: Correct. What we needed to do is to do the initial prediction. What we didn't want to do is wait until we got to EPU, updated the model with 111.5 and find out that we should have pulled up inspections early and it was too late because our last refuel outage was in the fall of 2007. So that's essentially what we did to it.

CHAIR ABDEL-KHALIK: Okay.

MS. KUGLER: This is Shelly Kugler. Just to correct Paul real quickly. The model was actually -- was inputted that mid-cycle, we'd actually go to 111.5% -- it didn't -- the full cycle was not in there -- so we could more accurately model with the EPU.

CHAIR ABDEL-KHALIK: Okay.

MR. DAVISON: Thank you, Shelly. On page 51 for what was the impact, the change of the EPU conditions did not result in any actual new systems being added to the FAC program. The evaluation of the inspection scope for the next two refuel outages did not identify any current scheduled inspections that needed to be performed earlier. That was that predictive and looking back to see if we needed to pull things up. So nothing was identified.

However, changing wear rates will occur as part of the EPU implementation. Therefore, additional baseline testing was added to the program scope. In fact, 9 new baseline components were added to the last refuel outage back in the fall, and 18 will be added to the next refuel outage which is our spring 2009 outage. The program is continuously updated to incorporate the operating conditions, as we mentioned earlier -- water chemistry, inspection results and any configuration changes that we would make via modification like as in small-bore piping.

Approximately 110 components are inspected each outage if you normalize them to how many we do per outage. As a result, numerous components have been replaced with FAC-resistant piping; typically, small-bore piping over the last several outages.

MEMBER ARMIJO: Along those lines, could you fill me in on the extent to which you use, for example, chrome-moly steels in your plant and the more vulnerable materials?

MR. DAVISON: Yes. Most of the original piping, small-bore piping wise, is carbon steel.

MEMBER ARMIJO: Carbon steel.

MR. DAVISON: Right. So everything we replace, piping system wise, is with the higher chrome content, chrome-moly steel so that it's FAC-resistant. Still, you know, puts -- it's captured in the program as an upgraded material that is not susceptible, but all the replacements we do have the less susceptible materials.

MEMBER ARMIJO: How about your bigger lines, steam lines, extraction lines, other stuff?

MR. DAVISON: Almost all of that is carbon. It's all susceptible. No specific replacements done. When we have an issue -- for example, back in 3R14, our last refuel outage, during the previous cycle, we had a through-wall leak of an extraction-steam piping T. Most of that large piping had been replaced with the upgraded piping materials. However, the T -- it's a 26-inch T -- was not, so it still remains susceptible. There was a kind of a discontinuity between the inner diameters of the T versus the piping in an upstream valve. It accelerated some wear. It was in the FAC program, did not detect it. We had a through-wall leak about 3/8-inch by 1-inch actual hole in the piping. When we went in to do the repair, which was go inside the piping in-body and do weld build-up on the ID of the pipe, we used FAC-resistant material when we did the repair on that T.

MEMBER ARMIJO: With a weld build-up?

MR. DAVISON: Correct, on the ID of the pipe. That's correct.

MR. WALLIS: This feedwater heater number 1, that's extracting wet steam, is it? That's -- I just wondered if the wetness changed significantly when you extracted more, presumably, with the upgrade and if the CHECWORKS really did a good job of taking account of that?

MR. DAVISON: Well, it was the -- that's our -- I mean that's why it's up on the screen. That is our highest prediction of change of wear rates roughly from 10 to 12 mils per year, which is why it's a target force mainly driven by the increased extraction pressure related to the turbine replacements and, of course, the power uprate condition.

MR. WALLIS: It's the pressure. Is it steam or is it steam with droplets in it? Is that part of the problem with the wearing?

MR. DAVISON: I don't know if there's anyone who can specifically help me with that. I know it takes into account the liquid drop impingement --

MR. WALLIS: It probably does because that's --

MR. DAVISON: -- part of it as well. Correct. And it also factors in cavitation in other circumstances as well.

MR. WALLIS: It's not really a safety issue anyway unless someone happens to be in the vicinity.

MR. DAVISON: Which is a locked high rad area for us in that condition. Nonetheless, we don't want to have steam leaks. In fact, we did an extended condition on the other ones and we'll be affecting some repairs because we do have some thinning, not anything that would go through-wall, but we are going to repair those, same methodology using the improving materials.

MEMBER ARMIJO: As a weld?

MR. DAVISON: Correct, ID build-up, inside diameter build-up of the piping T.

CHAIR ABDEL-KHALIK: The 10 to 12 mils per year, does that correspond to this maximum average wear rate --

MR. DAVISON: Yes.

CHAIR ABDEL-KHALIK: -- for that particular line?

MR. DAVISON: It's actually 10.5 to 12.3 is the prediction in increase. It's a .0023 inches per year increase in wear in that location.

CHAIR ABDEL-KHALIK: And just for reference, how thick is the pipe?

MR. DAVISON: It's -- we do have a nominal thickness on that, in the piping. I think it's 1-inch, but we can get that.

CHAIR ABDEL-KHALIK: How big is the line?

MR. DAVISON: Twenty -- do you have the piping size, Shelly or Paul?

MEMBER ARMIJO: What pipe are we talking about?

MR. DAVISON: Extraction steam in the number one feedwater.

MR. WALLIS: It's probably way above the thickness necessary to meet the requirement.

MR. DAVISON: Oh, yes, structural integrity, even with the through-wall, was never challenged. We did do structural analysis to make sure that even with the leak, we didn't have a structural integrity problem. This is strictly just through-wall leakage. And we have a set of PNIDs we can pull these --

MR. WALLIS: That's fine. We'll follow up later.

MR. DAVISON: Okay. So we talked about, you know, the highest one being this number one feedwater heater. We will be performing additional inspections in that particular area to validate the model and make sure we check it going forward, because that's our number one focus area.

Okay. And the last slide, 52, we have incorporated EPU into the model, made the necessary adjustments to our inspection program. No new scope was specifically added. Implementing EPU does not cause any near-term pressure boundary challenges associated with FAC and our components. They're adequately verified, inspected and checked in the model itself. And we don't foresee any specific challenges with increased flow.

If there are no questions, I'll go right into patient curves. Okay. In slide 53 and actually 54 and 55 are the three actual patient curves that were adopted back in November of 2004 when we did the uprate for the neutron fluence associated with the EPU conditions to ensure that the fracture toughness of the vessel material bounds the structural integrity requirements. The fluence was developed using the NRC methodology in accordance with the GE topical report. The curves are applicable through the end of life which is less than 32 effective full power years.

For all three individual curves, the upper vessel limit shown as the dashed line to the right there is impacted by the stress level increase associated with the feedwater flow, the feedwater nozzles flow and temperature changes associated with the EPU. The fluence impact on the belt line, which is the solid line, does not become limiting, and ultimately, the upper shelf energy remains greater than the code requirement for the design of the life, 50 foot-pounds.

One thing to add -- we are a member of the Integrated Surveillance Program for all the U.S. BWRs. However, Hope Creek is the only Hitachi vessel in the United States, and our specific data is actually only used for Hope Creek itself.

The first of three capsules were removed at the end of Cycle 5. Two capsules remain in the vessel. The second capsule will be removed in approximately 2014, which is one year earlier than the pre-EPU predication for the quarter-t fluence level. The third capsule remains in the vessel for future considerations. No specific plans on removing that capsule right now.

MEMBER ARMIJO: I guess I don't understand the issue about the Hitachi vessel. Now you can use the data from the other plants but they're not using the data from your plant? Or how --

MR. DAVISON: Yes. Actually, we are a member of the Integrated Surveillance Program because we share costs with the other folks who are in that, and we share lessons learned, generic lessons learned. Because we are the only Hitachi vessel, we really -- our data goes in and we use our own data. Nobody else can use the data. We're in it for the --

MEMBER ARMIJO: You can't use other people's data either --

MR. DAVISON: Not the specific data, correct. If they do lessons learned, changes in methods, something comes out that's applicable to everybody, we will take those learnings, so we want to be part of the learning organization from the, you know, the body of OE. But as far as data in-data out, it's our Hitachi vessel.

MEMBER ARMIJO: Okay.

MR. DAVISON: And that really ends my update on the curves unless there are specific questions. They've been in effect since 2004. We will be submitting for license renewal in August of 2009. At that time, they would be updated again and that methodology would be adopting or changing to the RAMA code for the fluence levels.

MR. WALLIS: Does this uprated power change the embrittlement life of the vessels significantly?

MR. DAVISON: No, it does not.

MR. WALLIS: It doesn't change it by year or something like that? It's less than -- presumably, there's more fluence? Is there more fluence or less -- depends upon how you arrange things, doesn't it?

MR. DAVISON: Yes. There will be more fluence.

MR. WALLIS: Okay, more fluence.

MR. DAVISON: In fact, when we get to vessel internals, we'll talk about the individual fluence levels --

MR. WALLIS: We'll do that tomorrow?

MR. DAVISON: -- on not only the internal components but the vessel itself.

CHAIR ABDEL-KHALIK: Are there any

additional questions for Mr. Davison?

(No audible response.)

CHAIR ABDEL-KHALIK: Are there comments that the staff would like to make on any of the topics that were presented today?

(No audible response.)

CHAIR ABDEL-KHALIK: Okay. We're adjourned for today.

(Whereupon, at 3:21 p.m., day one of the foregoing matter was adjourned.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards

Docket Number: n/a

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Charles Morrison
Official Reporter
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