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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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POWER UPRATE SUBCOMMITTEE

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PEACH BOTTOM ATOMIC POWER STATION, UNITS 2 AND 3

EXTENDED POWER UPRATE

+ + + + +

OPEN SESSION

+ + + + +

TUESDAY

JUNE 10, 2014

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ROCKVILLE, MARYLAND

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

COMMITTEE MEMBERS:

JOY REMPE, Chair
SANJOY BANERJEE, Member
DENNIS C. BLEY, Member
MICHAEL L. CORRADINI, Member
DANA A. POWERS, Member
HAROLD B. RAY, Member
PETER RICCARDELLA, Member
MICHAEL T. RYAN, Member
STEPHEN P. SCHULTZ, Member
GORDON R. SKILLMAN, Member

ACRS CONSULTANT:

KORD SMITH

DESIGNATED FEDERAL OFFICIAL:

WEIDONG WANG

T-A-B-L-E O-F C-O-N-T-E-N-T-S

P R O C E E D I N G S

(8:30 a.m.)

CHAIR REMPE: This meeting will now come to order. This is a meeting of the Power Uprate Subcommittee, a standing subcommittee, the advisory committee on reactor safeguards. I'm Joy Rempe, Chair of the subcommittee. ACRS Members in attendance are Michael Corradini, Mike Ryan, Steven Schultz, Dick Skillman, Harold Ray, Sanjoy Banerjee, and Pete Riccardella.

We expect to see Dennis Bley here soon. In addition, we have our ACRS consultant, Kord Smith here. Weidong Wang of the ACRS staff is the designated federal official for this meeting. In this meeting, the subcommittee will review the Peach Bottom Atomic Power Station, Units 2 and 3, license amendment request for an extended power uprate.

We'll hear presentations from the NRC staff and representatives from the licensee, Exelon Generation Company. We've received written comments and a request for time to make an oral statement from a member of the public regarding today's meeting also.

Foe agenda items, on nuclear design and safety analysis, containment analysis, and steam dryer analyses, the presentations will be closed in order to discuss information that's proprietary to the licensee and its contract as pursuant to 5 USC 552(b)(c)(4).

Attendance at portions of this meeting that deal with such information will be limited to the NRC staff and its consultants, Exelon Generation Company, and those individuals and organizations who have entered into appropriate confidentiality agreements with them. Consequently, we need to confirm that we have only eligible observers and participants in the room for the close portions of the meeting.

In addition, I need to ask the help of the staff, as well as the licensee, if some of our questions in the open part of the meeting require a proprietary response so that we don't violate that issue. The subcommittee will gather information today, analyze relevant issues and facts, and formulate proposed positions and actions as appropriate for deliberations by the full committee.

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the federal register. A transcript of the meeting is being kept and will be made available as stated in the federal register notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee.

The participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard. We'll now proceed with the meeting and I'd like to start by calling upon Ms. Louise Lund and Mr. Rick Ennis from the staff.

MS. LUND: Okay. Thank you and good morning. My name is Louise Lund and I'm the Deputy Division Director for the Division of Operator Reactor Licensing in the Office of Nuclear Reactor Regulations, and sitting right next to me is Rick Ennis, the project manager for Peach Bottom. And the staff appreciates the opportunity to brief the ACRS Power Uprate Subcommittee this morning on the Peach Bottom review, Units 2 and 3, Extended Power Uprate Application.

As you know Peach Bottom Units 2 and 3 are boiling water reactors owned and operated by Exelon. At this meeting, the NRC staff will present the results of our safety and technical review of Exelon's application. Next slide.

The NRC has previously approved 154 power uprates. Of the 854 approved power uprates, 29 are considered extended power uprates, requiring major modifications to the plant to achieve the increased power level. Of the 29 EPUs that the staff has approved, 11 were for pressurized water reactors and 18 were for boiling water reactors.

The proposed EPU power level of 3951 megawatts thermal, represents an increase of approximately 12.4 percent above that current licensed thermal power level of 3514 megawatts thermal.

MEMBER CORRADINI: Was there a prior uprate for Peach Bottom?

MS. LUND: Yes. In fact, there is. Yes. We'll get to that. Thank you, though. Since Peach Bottom had previously implemented a 5 percent stretch power uprate in the mid-1990s, and a 1.62 percent measurement uncertainty uprate in 2002, the proposed EPU represents an increase of approximately 20 percent above the original licensed thermal power level of 3293 megawatts thermal.

To put the 12.4 percent proposed EPU in perspective, here's a bar chart showing the 18 BWR EPUs that have previously been approved. As you can see, 15 of the 18 were for power levels greater than the 12.4 percent proposed for Peach Bottom. Our review of the proposed EPU for Peach Bottom was completed using EPU Review Standard RS-001.

This review standard has been used for the 17 EPU reviews approved since 2005. RS-001 contains guidance for evaluating each area of the review in the application, including the specific general design criteria used as the NRC's acceptance criteria. The guidance and the template safety evaluation contained in RS-001 is based on the GDC in Appendix A to 10 CFR Part 50.

Peach Bottom Units 2 and 3 were designed and constructed based on an earlier version of the GDC referred to in the staff safety evaluation as the draft GDC. As such, during the acceptance review, the NRC staff requested Exelon to submit a supplement to the EPU application to address the Peach Bottom plant-specific design and licensing basis.

Exelon supplement provided a revision to the template, safety evaluation in RS-001. The staff used this template in preparing the Peach Bottom for EPU safety and evaluation.

CHAIR REMPE: Somebody, I believe it's you, Rick, that's using the microphone. Yes. I'm sorry, but it bothers the recorder desperately.

MEMBER SKILLMAN: Louise, on that slide, is the review resource requirement of 9000 hours in the ballpark of other reviews or is this review significantly greater in resource use?

MS. LUND: We talk about -- we've looked at the amount of hours that -- and I would say it does tend to be in the ballpark. What tends to -- it's hard to generalize what a certain review is going to take because it's largely driven by special topics like steam dryers, you know, basically, the containment pressure, upper pressure, things that end up being very specific topics for reviews, so that's why it's kind of hard, but this, I think, in the ballpark, wouldn't you say?

MR. ENNIS: This is Rick Ennis. I think we've recently looked at some of the hours that have been spent on EPUs, and I think the average is around 7500. There's been some that I think has been as high as 13,000, and some that's been less. I think the BWOR reviews tend to be a little bit high a lot because of the steam dryer reviews, so it's in the ballpark.

MEMBER SKILLMAN: Thank you.

MS. LUND: The staff's review has been very thorough and involved a significant amount of effort, and of course, you'll hear about that this afternoon. The review has involved over 25 staff members in about 9000 hours of review time to date. Consistent with other BWR EPU reviews, a lot of that effort focused on the area of steam dryer analysis, and that's largely what has driven a lot of the hours.

Unless there are other questions, I'd like to turn it over to Rick Ennis, who is the NRC project manager for the Peach Bottom EPU review, and obviously knows a whole lot more about this than I do.

MR. ENNIS: Thank you, Louise. As Louise said, my name is Rick Ennis. I'm the NRC project manager for Peach Bottom in the Office Nuclear Reactor Regulation Division of Operating Reactor Licensing. Today you're going to hear presentations from the NRC staff and Exelon regarding the proposed EPU for Peach Bottom Units 2 and 3.

I'll present some background information regarding the NRC staff review and then I'll discuss the agenda for today's meeting. Throughout this meeting, you may hear people refer to the PUSAR. The PUSAR is the Power Uprate Safety Analysis Report which summarizes the results of the safety analyses performed by General Electric for Exelon to justify the proposed EPU.

A proprietary version of the PUSAR is included as Attachment 6 to the application, dated September 28, 2012, and a non-proprietary public version is included as Attachment 4 to the application.

The numbering in Section 2 of the PUSAR closely follows the section numbering in the NRC staff's draft safety evaluation that was provided to the ACRS on May 9, 2014.

Now I'd like to briefly discuss the timeline for the review of the Peach Bottom EPU. After Exelon submitted the application in September 2012, as with other license amendment requests, the NRC staff performs an acceptance review. In accordance with NRR procedure LIC 109, acceptance reviews are performed to determine if there's sufficient technical information in scope and depth to allow the staff to complete its detailed technical review.

As documented in the NRC staff letter to Exelon, dated December 18, 2012, the staff determined that supplemental information needed to be submitted in order for the staff to perform the detailed technical review. Three issues were identified.

First acceptance review issue related to the safety evaluation template. As Louise mentioned in her opening remarks, since Peach Bottom is a pre-GDC plant, Exelon was requested to provide a revised safety evaluation template reflecting the plant-specific design and licensing basis.

The second acceptance review issue related to additional information needed to support the replacement steam dryer analysis. This information pertained to, in part, the design differences between the Westinghouse replacement steam dryers and the original equipment General Electric dryers.

The third acceptance review issue related to the emergency core cooling ECCS analyses, specifically, the application provided a summary of the ECCS performance at EPU conditions, however, the NRC staff determined that the application did not have sufficient detail regarding the ECCS analyses in order to make an independent assessment.

The licensee provided the supplemental information requested by the staff in Supplement 1 to the application, dated February 15, 2013. After the staff reviewed the supplemental information, staff determined that the proposed EPU was acceptable for detailed review, as documented in our letter dated March 8, 2013.

The NRC's current timeliness goals for extended power uprate reviews is 18 months after the staff accepts the application for detailed review. As such, based on the March 8, 2013 letter, the staff established a forecasted review completion date of September 8, 2014. Completion by that date would support Exelon's implementation of the amendment in the fall 2014 outage for Unit 2 and Unit 3 would be implemented during the fall 2015 outage.

During the course of the review, the NRC staff sent Exelon a little over 200 requests for additional information, RAI questions. These RAI questions resulted in about 20 supplements to the application being submitted by Exelon. And to give you some perspective on the RAI questions that we asked, this graphic shows you that almost half of the questions were in the mechanical and civil engineering area of our review, and more than half of those questions related specifically to the steam dryer review.

Besides the steam dryer RAIs, we also had a significant number in the reactor systems and containment review areas. The reactor systems RAIs covered a number of areas, including fuel and core design, thermal hydraulic analyses, thermal conductivity degradation, anticipated transients without scram, and accident and transient analyses.

With respect to the containment review, the RAIs included questions in areas such as containment pressure and temperature response, containment heat removal analysis, containment integrity, and net positive suction head analyses. The NRC staff's presentations that we'll give this afternoon closely align with these focus areas that we had during the RAI process.

With respect to the agenda, this morning, Exelon will provide an overview of the extended power uprate. This discussion will address the plant modifications that will be made, including those that will be made to eliminate credit for containment accident pressure for the ECCS pump's net positive suction head analyses.

Following a break, Exelon will continue with a summary of the transient and accident analyses. Exelon will then discuss their flow-induced vibration and structural analyses for the EPU. The last presentation this morning will be discussion by Exelon on the power ascension test program that'll be used as part of the power uprate implementation.

Following a break for lunch, the four topics for this afternoon will be in closed session due to the proprietary nature of the information that will be discussed. The first presentation will be by the NRC reactor system staff and one of our contractors regarding the nuclear design and safety analyses.

Our second presentation will be by our containment and ventilation staff regarding the containment analyses. Exelon will then give an overview on the replacement steam dryers, and following a break, the NRC staff and our contractors will give their presentation on the review of the steam dryer analyses.

After the steam dryer presentation, we'll be back at open session for public and ACRS comments. And unless there's any questions, I'd like to turn it over to Exelon.

CHAIR REMPE: Okay. Thank you.

MS. LUND: Thank you.

CHAIR REMPE: I need to remind you to be very careful with the microphones. They're very tempting to hit.

MR. BORTON: Good morning. My name is Kevin Borton. I'm the licensing manager for power uprates from Exelon. We'll do a brief introduction and then we'll provide an overview, as Rick indicated, on the EPU change impacts modification, in particular, the cap elimination. Later this morning, we'll provide summaries of the accident flow-induced vibration analysis. We'll also take a look at our power ascension. And finally, during the closed portion, we'll discuss our overview of the replacement steam dryer assessment.

On Slide 2 here, just as a brief

introduction, excuse me, Slide 3, just want to introduce the folks here at the table and off to the side. Again, I'm Kevin Borton, the senior manager for licensing. Craig Lambert, who's over here to our right, he's the vice president of power uprate. Next to me is Mike Massaro. He's the site V.P.

John Rommel couldn't make it today. There was a death in his family, so we're going to be filling in for John. Ken Ainger is also at the side. He's our director for power uprates, EPU. Jim Armstrong, in the back here, is our reg assurance manager at Peach Bottom. Dave Henry, to my left, is the senior manager of design engineering at Peach Bottom.

And Jim Kovalchick is our senior manager of operations specifically assigned for EPU integrations. And then finally, Tony Hightower is our shift supervisor who's been working on the project for some time.

A little bit more about our team. Exelon embarked on the Peach Bottom project back in 2009 and initially staffed the project internally with Exelon individuals having previous EPU and large project experience. It's also important to integrate station expertise and knowledge, so earlier on, we dedicated an SRO, which is Tony over here, to work full-time on the project, along with station design engineers.

We also brought in GE and design engineers with Troy, Sargent & Lundy, who both have extensive knowledge in site and design history knowledge. And finally, we sought out EPU project experienced individuals and companies in order to caption for recent industry design and installation experiences.

Slide 5 is just a brief overview of our application. It was based on the approved GE topical reports, and as such, previous industry application experience and previous NRC staff's request for additional information were incorporated into the Peach Bottom submittal. And for ease of review, the application was prepared using the RS-001 format.

Okay. I'll turn it over to Mike Massaro, our site V.P.

MR. MASSARO: Good morning again. Mike Massaro, site vice president at Peach Bottom. A brief overview of Peach Bottom. Again, we're a General Electric BWR pool with a Mark 1 containment. Our operating license was issued in 1973 for Unit 2 and '74 for Unit 3. We began commercial operation in 1974, and those licenses were renewed in 2003, so for Unit 2, that license will expire in 2033, and Unit 3 will be 2034.

Our original thermal license power was

3293 with a stepped stretch uprate in '94 and '95 for Units 2 and 3 respectively, and we had MUR power uprates in 2002 to 3514, which is our current licensed power uprate. Our proposed EPU is 20 percent of OLTP, original licensed power, and 12 percent of our current licensed power uprate.

I'll go over some key parameter changes. Again, core thermal power with this proposed change would move from 3514 megawatts thermal to 3951. Licensed full power core flow range would move from 84.87 to 112.75, and from there, to 101.48, 112.75. Again, it is constant power pressure uprate, so no change in reactor pressure.

Vessel steam flow and feedwater flow increased proportionality with the power increase. Final feedwater temperature, we do expect, nominally, to remain 381.5. And CAP credit containment accident pressure credit will be eliminated, and we'll have a presentation that talks specifically to that.

MEMBER CORRADINI: When we visited you, I know you said this, but I can't remember, so the 110 percent of full power flow range has always been there or is that something you guys had done recently?

MR. MASSARO: No, that's always been there.

MEMBER CORRADINI: All right. Thank you.

MEMBER BANERJEE: I mean, it can be actually operated at 110.

MR. MASSARO: No, we have not been able to achieve 110.

MEMBER CORRADINI: That's what I remembered, you guys gave us a discussion, but I don't remember, but it can be over 100. There's some limit on the heat exchangers? Am I remembering correctly? I'm sorry.

MR. MASSARO: The limit, I believe, is recirc --

MR. HENRY: This is Dave Henry from Exelon. The limitation that we run into is recirc pump speed, 1660 rpm speed, and with the jet pump efficiency, depending on where we're at in cycle, we can get close to 110 percent, but not up to 110 percent.

MEMBER CORRADINI: Okay. All right. But it doesn't make it, but you can go above 100, is what I remember.

MR. HENRY: Absolutely. Yes.

MEMBER CORRADINI: Okay. Thank you.

CHAIR REMPE: Also, could you just clarify, from what we've been reading, what fuel's in the plants now and what fuel will be in the plant when you start the EPU?

MR. BORTON: Right now we have a mixture of -- it's all GE fuel. It's a GE14 and a GNF2 fuel, but for power uprates for both Unit 2, we'll have full core GNF2 fuel.

CHAIR REMPE: Okay.

MEMBER BANERJEE: So for the EPU, do you intend any operation about the 100 percent bar within the 100 to 110 to do any flow control?

MR. BORTON: Prior to EPU?

MEMBER BANERJEE: No, no. After EPU.

MR. BORTON: Could you state the question again?

MEMBER BANERJEE: Let's say, after you have your EPU, would you be considering any operation above 100 percent of core flow?

MR. BORTON: I believe the answer to that is yes. I'll turn it over to Tony. Yes.

MR. HIGHTOWER: Yes. Tony Hightower, Peach Bottom operations, and yes, we will continue to use the flow region above 100 percent.

MEMBER BANERJEE: But that would be used, essentially, to do some full control?

MR. HIGHTOWER: Use of the flow region above 100 percent will allow us to maintain power through our operating cycle using flow control. It'll allow us that flexibility.

MR. MASSARO: Tony, I believe that we were looking at a flow range from 99 to 103, correct?

MR. HIGHTOWER: That's correct, Mike. The 103 is based on the capability of the recirc system. We'll continue to be licensed to the 110 percent core flow. The 99 percent is the limitation with the EPU power to flow map.

MR. MASSARO: Right. Thanks, Tony. Okay. With that, I'll move into major modification summary. Again, these are major mods that improve reliability and operating. There are a number of other modifications, which I won't cover here, unless there are questions about it. We are adding one main steam relief valve. That'll be set at 1260 psig, that is of the same manufacturing design as the existing two. We currently have two per unit.

It'll be added to the Charlie main steamline and replace by removing a blank flange and placing a dresser SRV in that location. We'll be replacing the steam dryer, and again, there will be a separate presentation regarding the steam dryer. That'll improve our moisture carryover significantly. We have found that a lot of our BOP plant steam cytosis are a result of cobalt carryover.

This modification will not only improve stress ratios on the dryer, but it'll also improve reliability and doses in the plant by reducing moisture carryover.

MEMBER CORRADINI: I'm sorry, but again, back to what you guys were telling us when we were there, and I'm trying to remember, did you guys already do a turbine blade expansion so that you got a bit more out of electrical power? And that helps there too I assume.

MR. MASSARO: We've already replaced all the LP turbines on both units.

MEMBER CORRADINI: Okay.

MR. MASSARO: So three LPs on each unit have been previously replaced.

MEMBER CORRADINI: This would extend the life on that lowest stage, right? Am I remembering correctly? In other words, you don't have the chance of the last stage replacement is -- of not replacing it is improved by, essentially, reducing moisture carryover, if I remember it correctly?

MR. MASSARO: I'm not so sure that it has that much to do with moisture -- the DLP last stage has that much to do with moisture carryover.

MEMBER CORRADINI: Okay. All right. Thank you.

MEMBER BANERJEE: Do you use zinc in this plant?

MR. MASSARO: Yes, we do.

MEMBER SCHULTZ: Mike, you're going to go through a number of modification descriptions here. Exelon has got, in a sense, a unique -- is in a unique position in that, it's a company that has many BWRs, many have been through an uprate process, and I'm just interested knowing, as you go through the modifications, which would be considered new in terms of application, that is, is Peach Bottom doing modifications which are different from what has been done before; unique for the plant; unique for the fleet?

MR. MASSARO: Okay. I will --

MEMBER SCHULTZ: And Dave might want to pitch in on that too.

MR. MASSARO: That's fine. I'll touch on those as we go through.

MEMBER SCHULTZ: I'd appreciate that. Thank you.

MR. MASSARO: You know, I'd start out by saying the containment accident pressure elimination modifications, for the most part, are all unique. Next on here is high pressure turbine replacement. As I mentioned, we've replaced all the LP turbines, three per unit, previously, and with EPU, we'll replace the high pressure turbine. That'll be an awesome designed machine, it will not have shrunk on rotors, and it will fit within the existing shell, so essentially, we're replacing the rotating element, diaphragms, and the like. The shell will remain the same.

Feed pump turbine upgrades, the reactor feed pump turbine upgrades, we have three feed pump turbines on each unit. What we're proposing to do here is replace the turbines on each of those feed pumps, including casing and all components within the casing. We will not be replacing the feed pumps themselves, just the turbines.

And that's a result of our analysis that there would be increased stress on some of the blades in the existing feed pump turbines. I would mention that, unique to Exelon fleet, we have benchmark, and we are looking at the experience that, I guess it's free to say, Susquehanna's had, so they're one of the units we're looking at that's done something similar in this area.

Feedwater heaters. We've reviewed all our feedwater heater current condition, material condition, for uprate, and we are replacing one on Unit2, and four on Unit 3. We've already replaced two of the ones on two of the LP turbines, or second stage -- I'm sorry, second stage feedwater heaters on Unit 3 in the last refueling outage.

This outage, we'll be doing one on Unit 2 and then in 2015, we'll be replacing the other two feed heaters on Unit 3. And again, the other feed heaters have been analyzed and verified to be acceptable for EPU conditions. And that was mostly the result of some internal degradation in the feedwater heaters and two flooding conditions.

Reactor water cleanup modification, we have done similar modifications to this in other parts of the fleet, and some of our fleet is following us in this. We are not increasing flow-through reactor water cleanup system as part of this modification. What we are doing is improving the efficiency of the cleanup system through a number of modifications.

One is an integrated flow distributor to get a more even resident distribution in the cleanup system. We're also doing a vessel slow pressurization mod, if you will, not to disturb pre-coat, and a metered pre-coat as well as a modification to the backwash system to get a better backwash on the reactor water cleanup filter deviance.

Condensate pump motor upgrades, would not say that we've done something similar to this through the rest of the fleet, but it is pretty straightforward in terms of its design. We will be installing new pumps in the existing wells. These will require new motors as well as upgraded motors, so pump motors will go from 4500 horsepower, nominally, to 5000 horsepower, nominally. And again, new pumps in the existing wells with new motors.

Condensate filter demineralizer. We have ten condensate filter demineralizers on each unit. The modification here, which is, I would say, unique to Exelon, is to add two filter demins. They would be very much the same as the existing ten and it will improve the capacity of the condensate demin system by 20 percent.

The controls will be modified for all ten, but that's strictly for backwash and pre-coat control. So pretty straightforward modification in terms of complexity, the large piping job, and, you know, with two additional vessels being added.

Main steam pipe piping. We did review our main steam piping support design and found that for EPU conditions, we needed to make some upgrades to the piping supports, including snubbers and supports. We implemented those changes on Unit 3 in the last refueling outage last year. That would include the analysis was performed all the way from the reactor, essentially, to the turbine control valves, and those modifications were performed both inside and outside containment.

So modifications completed on Unit 3, we have had good experience and no issues with that on Unit 3, in our experience, and expect to do the same thing on Unit 2 this coming refueling outage.

MEMBER SKILLMAN: Mike, what are the details on the inspections? With new supports and snubbers, that's great you're holding down the higher mass flow rate, and the velocity, that type of thing, what kind of inspections preceded those mods to make sure that the piping that remains is fit for duty?

MR. MASSARO: Well, you're asking about --

MEMBER SKILLMAN: Pipe.

MR. MASSARO: -- prior to design, the walk-downs that --

MEMBER SKILLMAN: Well, no, you've been operating for years, you're not changing piping, you're strengthening the support and restraint system.

MR. MASSARO: Right.

MEMBER SKILLMAN: And I'm asking about the piping that is being supported in the restraining, but what inspections were performed so that we know that that piping is not vulnerable to steamline break?

MR. MASSARO: If we could, take that question and relay that back and get you an answer before the closed session today.

MEMBER SKILLMAN: Yes, thank you.

MR. MASSARO: I would say that there was initial inspection on Unit 3 as we entered the refueling outage to go in an verify the condition of piping supports as part of the ECR, what we expected to find there, not only in terms of configuration, but in terms of condition. You're asking specifically about the piping. We'll followup with that.

MEMBER SKILLMAN: Thank you, Mike.

MR. MASSARO: Main generator modifications. We did purchase a new main generator rotor for Unit 3 and installed that rotor in the last refueling outage in 2013. The rotor from Unit 3 was removed and has been sent off to be upgraded and will be installed in Unit 2 this coming refueling outage. As part of that as well, we -- and that'll give us the necessary MVA margin that we need for EPU conditions.

As part of that as well, we replaced the

Alterex on Unit 3, which included the doghouse, if you will, and that was all completed on Unit 3, as well as the automatic voltage regulator. All those mods were completed on Unit 3 in 2013; in the fall. We've had good experience with those modifications to date. And essentially, expect to perform the same thing on Unit 2 this coming refueling outage, with the difference of the rotor will be a refurbished rotor as opposed to a brand new one.

Isophase bus duct modifications, this mod has been performed at other facilities in our fleet. Essentially, we're replacing portions of the isophase to support the additional power. We did perform this modification on Unit 3 in the last refueling outage, so it was completed, and have had good experience with that as well, and we except to do, essentially, the same thing on Unit 2 in the upcoming refueling outage.

The duct work goes from, nominally, 30-inch sized duct to 40-inch sized duct. It's not complete replacement, but the majority, I would say, between the generator out to the area of the in-power transformers has been replaced.

ATWS recirc pump trip, we found as a result of our analysis that the ATWS recirc pump trip needed to be moved from the dry motor breaker to the generator output breaker, I hesitate to say EOC breaker, but to the breaker that also performs the end-of-cycle RPT trip. That modification will be performed and established by installing an additional trip coil on that EOC RPT breaker and moving, essentially, the logic signal from the dry motor breaker to the EOC RPT breaker.

That is not particularly complex in nature. I'm not aware of any other plant in our fleet that's done that, but I wouldn't expect to have any issues. We do have other plants that have dual trip coils, you know, experience.

Motor-operated valves, we found that from our review there were a handful of motor-operated valves that would either be below margin or low margin as a result of EPU, and those valves will be modified in the upcoming refueling outage to support it.

We have a low margin program where we continuously review valves. There are eight valves, essentially, that require modification. They're all associated with ECCS suction at the suppression pool in the torus, you know, at HPCI, RCIC, core spray arch. And those valve modifications will typically include gear train modifications, not valve replacement.

RHR, the modifications on this page are

specifically associated with CAP credit elimination. I would say that all these modifications are fairly unique within our fleet, and there will be extensive discussion on them. I'll just touch on them briefly, but essentially, we've got other experts in the room that are probably better versed on talking to them.

An RHR heat exchanger cross-tie mod. This will install a 10-inch cross-tie within divisions on each of the RHR systems. We did a portion of this in the last refueling outage in unit 3. We did not complete the cross-tie modification. This was to gain some knowledge about the difficulty. Most of this is piping work and so we started into this in the Unit 3 refueling outage. We expect to do both divisions in the upcoming Unit 2 refueling outage.

Again, it's a 10-inch cross-tie modification within divisions, which will include a valve to be able to balance flows through the RHR heat exchangers for CAP elimination. HPSW, high pressure service water cross-tie goes along with the RHR cross-tie. It's part of CAP elimination. This is the pooling water system for the RHR heat exchangers, and essentially, this'll provide us a mechanism to cross within divisions, also, to be able to cool RHR in the event of a loss of a diesel or a vital bus.

MEMBER SKILLMAN: Mike, for those two modifications, the cross-tie for the RHR heat exchangers, and the high pressure service water cross-tie, in creating those cross-ties, have you violated any of your string independence or credited redundancy from your license?

MR. MASSARO: No, we have not, and I think we can explain more or get into further details as we do that. Again, it's within divisions and that's been all thoroughly reviewed as we've gone through the process.

MR. HIGHTOWER: This is Tony Hightower from Peach Bottom. To clarify, the HPSW cross-tie itself was between divisions. RHR is within divisions. The HPSW cross-tie is an existing cross-tie that we have for operational flexibility. It's used after we have a single failure so it allows us to continue to meet our separation criteria, and operating procedures will be tailored to ensure that we only operate that cross-tie after that single failure of safety-related component has occurred.

MR. MASSARO: Thank you, Tony.

MEMBER SKILLMAN: Thank you.

MEMBER SCHULTZ: Mike, you've got a couple more on this slide?

MR. MASSARO: One more. Well, actually, two more, condensate storage tank modifications, which include a standpipe to preserve volume within the CST, again, this is for CAP elimination in the event of an Appendix R fire. And that also -- what goes hand-in-hand with this is raising the torus suction swap-over to HPCI, again, to preserve inventory in the CST.

And last is standby liquid control system. This is a modification to support. Essentially, what we're doing here is increasing atom weight of boron-10 in the SLC system. There is a marginal increase in inventory level, but that's specifically the change in boron concentration is to support ATWS. The change in level is to more support the pH within the torus post-accident.

MEMBER BANERJEE: Could I ask you a question, which you don't have to answer, why did you decide to do this?

MR. MASSARO: I can get a little bit more into that --

MEMBER BANERJEE: Will you get into it?

MR. BORTON: Yes.

MEMBER BANERJEE: Because it's interesting. As you know, of course, plans are going forward with CAP and this is a very nice way to do it, I'm sure, but it involves a little additional costs, so I'd be very interested to know the answer to that.

MR. BORTON: And to cut to the chase a little bit too, we had the opportunity to do it here. We have kind of a unique design, you know, where other plants did not. So I'll get into that --

MEMBER BANERJEE: Okay. Great. But you take some sort of a financial hit on this, right?

MR. BORTON: There is an expense to making this modification, of course.

MEMBER SCHULTZ: My question on the modifications goes to, you mentioned a number that have already been implemented on Unit 3, but not all have been implemented there, and you didn't mention Unit 2 associated with any previous work here, so how are the modifications going to be implemented going forward on Unit 2 and then on Unit 3? If you're going to discuss the process later, I'll wait, but I'm interested in knowing what the sequence of events is for each of the units going forward.

MR. MASSARO: Well, we will install all the modifications that I've covered here, and then some, on Unit 2 in the upcoming refueling outage, which starts in October. That'll put everything in place to support EPU. The remainder of the modifications on Unit 3 will be installed in 2015 in that refueling outage.

MEMBER SCHULTZ: And then Unit 3 will proceed to the upgraded condition.

MR. MASSARO: Correct.

MEMBER SCHULTZ: Good. Thank you.

CHAIR REMPE: But Unit 2 goes through the EPU first, right, from what I've read and the dryer, it will be installed this fall?

MR. MASSARO: That's correct.

MEMBER BANERJEE: Does this have any implications on GSI-191?

MR. MASSARO: GSI-191?

MEMBER CORRADINI: You got to help him.

MEMBER BANERJEE: Debris blockage, because, you know, the flows are being reoriented and I don't know what all the implications of this are.

MR. MASSARO: Torus suction. Debris blockage within the torus, that was considered as part of the modifications to the RHR system. Core spray system is essentially remaining unchanged to RCIC, and no significant modifications, clearly, that was a design consideration.

MEMBER BANERJEE: But you took that into

account, was there increased flows or anything that occurred?

MR. MASSARO: Actually, when they talk about the modifications, we'll find that, for the RHR systems, the flows were decreased.

MEMBER BANERJEE: Okay.

MEMBER SCHULTZ: Mike, as you went through and talked about the modifications on Unit 3, a couple of times you mentioned that there were no issues associated with those modifications. Were there any issues associated with modifications in terms of lessons learned?

MR. MASSARO: There were, clearly, lessons learned from the modifications. The RHR cross-tie, we had lessons learned about some of the difficulty in dealing with the contaminated piping welding. That was a large learning. The main generator rotor upgrade, we actually, by design, employed too many additional brushes in that design and had to go and reduce some of the brushes. We employed more brushes to support EPU. It turned out that that didn't provide the current density that we needed, and we found that as we came out of the outage by an accelerated degradation of the brushes. We've since reduced that brush configuration to local support current power level.

We have critiques from all of the mods. We actually had also done a causal analysis, put them all together and done a causal analysis, a root cause around many of the modifications to make sure that we understood all the things that we needed to improve and improved going into the Unit 2 refueling outage.

The modifications associated with the EPU on Unit 3, none of them were necessarily mandatory in the Unit 3 outage. So, you know, that was a learning outage for us with respect to how difficult it would be to do the mods and we took that opportunity to do that, so clearly, we step back and look at lessons learned from those modifications.

MEMBER SCHULTZ: Good. Thank you.

MR. BORTON: Okay. I'd like to move on to the next major modification that we did. Again, John Rommel could not be here today with us. He had to be with his family. So I'll present today using John's notes and the support of the other members of the team here who worked on the elimination of CAP credit. So turning to Slide 15. This should be a familiar figure here.

As part of our initial EPU strategy, we included an investigation to the practicality of eliminating the need for containment action to pressure credit at Peach Bottom. We considered it as an opportunity to improve the NPSH margins and effectively, remove any industry concerns that might exist with CAP credit at Peach Bottom as well.

So referring to this simple diagram. The term in question here is the head generated by the atmosphere present, and that's in this section here of course, that's present in containment. So our current licensing basis allows for some of the pressure generated during an accident or special event, to increase the value of this term above that pre-accident condition.

MEMBER BANERJEE: Can you remind us for how long and -- you had 6.1, was that psi?

MR. BORTON: Right, psig.

MEMBER BANERJEE: Psig, and for how long was that needed?

MR. BORTON: Tony, I think that was for the shorter portion of the accident. How long CAP credit is needed and --

MEMBER BANERJEE: Apparently needed.

MR. HIGHTOWER: Right. This is Tony Hightower from Peach Bottom. I don't have the specific answer to that question.

MEMBER BANERJEE: Could we get it?

MR. BORTON: Mike?

MR. MASSARO: We can get that answer. This is Mike. We can get that answer.

MEMBER BANERJEE: Thanks.

MEMBER CORRADINI: If you're going to go through all the effort to find the time, what was the limiting accident that needed it? I can't remember which one it was. Was it LOCA or is it plant-wide?

MR. BORTON: Yes, I'm going to get through that, each one of them, so each one will be addressed here.

MEMBER CORRADINI: Okay. Sorry.

MR. BORTON: Again, this is just really an overview to look at that we did for the CAP credit elimination. Of course, the equation here, you know, the atmospheric that we're talking about here, the static head, any losses due to the piping and valving configuration, and then vapor pressure in the pump, which is also a reduction.

So in order to address the opportunity, we look at a number of option combinations and concluded that a practical design was possible that would eliminate the need for CAP credit at Peach Bottom. Thus, as part of our EPU submittal, we provided a design that eliminated the need for CAP credit. In the next few slides, I'll go and describe the key elements and the actions we took to make that happen.

MEMBER BANERJEE: Did this process start when we were still fighting over CAP credit or was it --

MR. BORTON: Our process was, you know, we started in 2009, it was around 2010, we started looking at CAP credit and the opportunity to remove that. So it was two major reasons, one is, we looked at the opportunity we had, perhaps, a means, so we started the investigation into that, and as we got further into it, we saw we can improve the margins, and of course, we would avoid any unnecessary delays or anything else with EPU.

Okay. Slide 17, I'm on right now, to start, we had a little background, so we had CAP credit for both accidents and special events. And while the debris of credit varies from event to event, currently, we take 6.1 psig that occurs in the long-term portion of the local, so we'll find out a little bit more detail and we'll get that back to you on that as well.

I'd like to move on to Slide 18. So this is, essentially, how we looked at removing CAP credit, and there is not really one-size-fits-all-type answer.

Some of the actions we took applied to accidents and other were special events, and some impacted both. As this slide describes, there's a high-level, four key actions that were required to eliminate CAP credit and I'll go through each one in more specific detail. I'll follow-up on subsequent slides here.

But for now, the four key steps in the CAP credit elimination were, the first one was, to increase the RHR heat transfer capability and remove more heat allows for the reduction of pool temperature. This reduces the loss due to vapor pressure and it also increases the heat removal capacity accomplished. We did that in two major steps.

First, the RHR in the HPSW cross-tie modifications were performed, and I'll walk through them in greater detail in a couple of slides, and then second, we reduced the amount of allowable fouling in a generic letter 8913 test program for the RHR heat exchangers. In this case, we looked at the past test data and we saw that there was a margin between the actual performance and what our design basis was, so therefore, we took advantage of some of that high margin and left ourself some margin as well.

MEMBER CORRADINI: So this is a chemistry effect, the actual fouling that you're measuring is much less than the assumed fouling.

MR. BORTON: That's correct.

MEMBER CORRADINI: And do you know the source of why it's better than what you assume or did it just turn out, empirically, it's best?

MR. BORTON: We just looked back and that's what we found.

MEMBER CORRADINI: But I mean, the root cause is chemistry change? I'm just kind of curious what it was.

MR. BORTON: It was more likely, and we'll go back and take a look and see if we can find an exact answer to that question, but it's basically, we had over-designed. We had more margin in our design.

MEMBER CORRADINI: Okay.

MR. MASSARO: And I would also say that the preventative maintenance program cleaning program on the RHR heat exchanger is factored into that as well.

MEMBER CORRADINI: Thank you.

MEMBER BLEY: Does this imply a commitment to ensure that you maintain that margin?

MR. BORTON: Yes, it does.

MEMBER BLEY: Thank you.

MR. BORTON: So there'll be a new cleanliness criteria that we have for just the heat exchangers. The second key action, we needed to reduce the required RHR pump flow, which was a question that was asked earlier. Lowering the RHR flow reduces the MPSH required values without significantly impacting a de-cladding temperature of results.

The third key was to use the condensate storage tank as a water source during special events. The extra water inventory helped reduce the pool temperature, vapor loss, again, as well as it adds extra height, increasing our static head, both which increase the available MPSH.

And then I'll get into more modifications and more details about the CST in a couple slides here, but finally, we increased the standby liquid control boron-10 enrichment to 92 percent. This results in a more rapid power reduction in the ATWS event and then less heat being added to the containment.

MEMBER BANERJEE: So I mean, one important effect is that the water in that tank is colder, right?

MR. BORTON: Yes.

MEMBER BANERJEE: And how much colder is it compared to the peak? Is it 10 degrees Celsius or Fahrenheit colder?

MR. BORTON: For our suppression pool?

MEMBER BANERJEE: Yes.

MR. BORTON: Yes, so for the accident conditions, the cross-tie, we did it on that, our heat removal capacity, and I'll go into that, went up about 65 percent.

MEMBER BANERJEE: Oh, that much.

MR. BORTON: Yes.

MEMBER BANERJEE: So it's quite a bit colder.

MR. BORTON: Yes, 1.6 times greater than it was prior to that.

MR. DICK: This is Michael Dick from Exelon. Actually it is, for the design basis LOCA, at current power level, the design analysis had a peak pool temperature of 206 Fahrenheit, and at EPU condition, with the use of a cross-tie, the peak temperature goes to 187.6, I believe. So effectively, we've reduced that temperature significantly, plus we've overcome, essentially, what you would assume the normal increase of about 10 degrees of the effective EPU.

So the net effect is about a 30 degree increase in heat removal capability for the containment.

MEMBER BANERJEE: Thank you.

MR. BORTON: In the suppression pool.

MR. DICK: Suppression pool.

MR. BORTON: Yes, I'm sorry. I was talking about the heat exchanger earlier. So this slide shows how each of the different actions we took impacted the various event analysis and integrated to an overall strategy to eliminate the need for CAP credit.

As you can see, the RHR and the HPSW here really effect the accidents and the condensate storage tank actions are specifically for special events.

MEMBER BANERJEE: So with the reduced flow, you got some additional margin on MPSH, right?

MR. BORTON: That's correct.

MEMBER BANERJEE: Are you going to go through us for that; how that changes --

MR. BORTON: Yes, we're going to go through each one of those and tell you the differences here. The K-factor for the heat exchanger, for cleanliness, and the RHR pump changes impacted the overall RHR system, so they pretty much address all the events. And what I'd like to do is -- well, I guess, to answer your question now, looking ahead, we're going to go through how each one of those go through, and I think I can --

MEMBER BANERJEE: That's fine. Just take your time.

MEMBER CORRADINI: Just remind me. I think I understand why the X's aren't in ATWS and SBO for the cross-tie. Why isn't it in the Appendix R? I don't remember. Is there a failure there; an assumed failure?

MR. DICK: This is Michael Dick from Exelon. Essentially, it is that there are, I believe, about 70 Appendix R scenarios. As you go through the plant, you assume fires in each one of the different rooms and area of the plant. Well, essentially, when we were looking to see if we could use the cross-tie for those events, we found that we could use it for the majority of the room fires, but we couldn't use it for all of them.

MEMBER CORRADINI: So you're limited by the most --

MR. DICK: Yes, so we did not credit it for any fire events.

MEMBER CORRADINI: All right. Thank you.

CHAIR REMPE: When I looked through the material that was provided to us, there's design basis analysis and conservative analyses, and I believe it was in the design basis, well, in both cases, there were different assumptions made for the current power level versus the EPU, and sometimes the explanation was that we did sensitivity studies and picked the worst value, but I believe you did those sensitivity studies on a parameter-by-parameter basis individually.

And it wasn't clear to me that you really nailed the most limiting value sometimes, and I wasn't sure how important those assumptions were made. I didn't see anything in your slides about this. In the staff's slides, they mentioned that they had some questions about how these parameters were selected, but they were resolved, but I would really like to hear your explanation of how this analysis was done, if you could. Maybe that needs to be in the closed session, but I --

MEMBER BANERJEE: This is not closed?

CHAIR REMPE: This is open right now. And so I would appreciate having a little more detail so that I felt a bit more comfortable about what I was reading.

MR. BORTON: Okay. And I think you're talking about a few items that go beyond the CAP as well.

CHAIR REMPE: I believe most of it was put in the framework for CAP, and especially in the staff's presentation, and where it was located in the documentation, but it would just --

MR. BORTON: We'll go over those details in that session later this afternoon.

CHAIR REMPE: Okay. I'd appreciate that.

MEMBER BANERJEE: So you can refuse to answer any questions.

MEMBER CORRADINI: So one other clarification, the number 2 bullet and the number 3 bullet, increased and reduced, they're coupled, right? They're really the same effect. You get better heat exchanger performance so you don't need to run the pump as fast, right?

MR. BORTON: Right.

MEMBER CORRADINI: Okay.

MR. BORTON: So there's really a combination --

MEMBER CORRADINI: Okay. So it's a coupled effect. That's why it's applicable across the way. Let me ask you another question, at least since it's applicable across the way, did you guys do an analysis, because you're taking credit for reduced fouling, does that remove you out of CAP credit or does that take you a lot of the way there? If all the other things were disappearing, would that take you all the way there or where does that take you?

MR. BORTON: Each and every one of these were required to reduce CAP credit.

MEMBER CORRADINI: Okay.

MEMBER BANERJEE: I guess his question is one that I also had. If you only took the increased credit for fouling, how far would it take you? Like, you got a 30-degree change in temperature there, or something like that, would you be able to get 5 degrees with that, or 10 degrees with that, just out of the reduced fouling?

MR. BORTON: We can take that as a follow-up until we know -- do you know that?

MR. DICK: This is Michael Dick. I can answer --

MEMBER BANERJEE: Give a rough number.

MR. DICK: -- your question more in a qualitative sense, in that, the two most important items were the changes in the K-factor, increased heat removal from the heat exchanger, but it was also necessary to reduce the RHR flow rates.

MEMBER CORRADINI: All right. Thank you. Because that was your limiting accident way back when. Your highest required CAP was 6 psi, but because of LOCA, if I remember correctly, right?

MR. DICK: That's a correct statement, sir.

MEMBER CORRADINI: Thank you.

MR. BORTON: Okay. So getting a little

bit more into the details here. So this Slide 20 gives a simple overview of the RHR and the high pressure service water cross-tie modifications. And I'm going to drive here and speak at the same time here, but I'd also like to leave this slide up as I go through the other segments so you can get an idea of what all the modifications were.

Peach Bottom is different than the other plants in that, the fact that there's four heat exchangers per unit. A lot of the vintage plants and this size plants only had two heat exchangers. The original design analysis requires only crediting one heat exchanger, so therefore, there's an extra heat exchanger removal capacity here that, if we could tap into it, you know, with process and cooling water, we would gain extra cooling effect here for the heat exchangers.

So to take advantage of that extra heat exchanger, we added this cross-tie valves right here, just downstream of the pumps with normally closed valves in-between them. We also included new control valves upstream. There was a control valve on one and a flow restrictor in another one.

We put new elements, also, downstream of the heat exchangers to measure our flows. This change allowed us to change our flow process and add the extra heat exchanger, so we would pump through one pump going to two heat exchangers, and that's only half the equation, because the other half of the equation is our HPSW pumps on this side.

So we replaced the existing cross-tie that was there for only outage purposes with a valve that could be opened against full flow and pump differential. This allowed any available HPSW pump to supply the cooling water to the extra heat exchanger, and the combined effect of the RHR cooling increases the heat removal capacity by about 65 percent.

So with these modifications, along with the reduction in the RHR pump flow, and the reduced fouling, we successfully reduced the post-accident pool temperature to a point where the MPSH available is greater than the MPSH required, and thus, effectively eliminate a need for CAP credit for accidents. So this is really -- I just gave you the accidents --

MEMBER BANERJEE: Don't go so fast.

MR. BORTON: So I'm going to stay here and answer questions.

MEMBER BANERJEE: Yes, right.

MEMBER BLEY: While we're waiting for

questions, I just wanted to mention that, while I share Professor Banerjee's curiosity and interest in this, two points, I think you mentioned, Sanjoy, this has some cost associated with it, but should you ever need the CAP credit and not actually have it, the cost associated with that could be a hell of a lot more, so you have to look at the likelihood of it being there, and we haven't stopped arguing over this.

Several of our letters this year have dealt with CAP in a couple of specific cases, so we're still very interested.

MEMBER BANERJEE: Yes, I think, in a way, what you're saying is prudent to it.

MEMBER CORRADINI: Can I ask the question a little differently? So let's say you did all this, there was a question earlier, and I don't remember how you guys answered it, which is, so is there no downside to this? There must be some sort of accident situation that this causes you pain somewhere else where you get the gain here? Has that analysis been done? I've been waiting for Dennis to ask this question, but I don't understand enough of the details of the plant system that I can't guess what that would be.

MEMBER BLEY: There must be, and if their valves are not in the position that they've assured themselves they are, there could be a problem.

MEMBER CORRADINI: So that's kind of the root of my question, have you guys done some sort of analysis that says, okay, now we installed this and now there's a misalignment, this takes me down a path I wouldn't have expected later on in terms of an accident sequence?

MR. DICK: This is Michael Dick with Exelon. The downside of this modification, other than the cost, okay, is the --

MEMBER CORRADINI: You guys got the money.

MR. DICK: Right. But as far as in a safety analysis space is the reduction in RHR flow during a LOCA. And now I'm talking about fuel LOCA, okay, because both the runout flows we -- two things we did with this mod is, as far as the long-term RHR flow and also the short-term run-out RHR flow. So what we see is, is a hit on the large break LOCA fuel results, and I believe that is about a 30-degree hit on peak cladding temperature, but that's for the large break LOCA.

Peach Bottom is not a large break LOCA limiting plant. It's a small break LOCA, and so this modification actually has zero impact on the licensing basis PCT.

MEMBER BANERJEE: There's a fairly large margin of error, correct?

MR. DICK: Yes.

MEMBER BANERJEE: Did you use a best test simulator analysis or what did you do for the LOCA mark? Well, you'll revisit LOCA sometime, so we'll leave it for that.

MR. DICK: Michael Dick. It's ECC -- use the GE/Hitachi or GNF SAFER/PRIME methodology. That's the licensing basis methodology.

MEMBER BANERJEE: Okay. That's fine.

MR. BORTON: Any other questions on the accident side before I move on to special events?

MEMBER BANERJEE: So going back to the pumps, I didn't quite follow what you did to that red valve on the right.

MR. BORTON: This right here?

MEMBER BANERJEE: No, no, no.

CHAIR REMPE: Over to the right more.

MR. MASSARO: Yes, that valve previously existed. We upgraded the operator, essentially, to be able to open against dead head.

MEMBER BLEY: They had a valve you couldn't open before if the system's operating.

MR. MASSARO: Yes, we also added manual

maintenance valves on either side of the cross-tie to be able to service that pump.

MEMBER BANERJEE: Okay.

MR. BORTON: Okay. Just moving on, since we eliminated the CAP credit for the accidents, and -- I'm sorry. I'm on the wrong slide. So to take advantage of the extra heat exchangers gave us action to credit --

MEMBER BANERJEE: What sort of heat exchangers are these RHR heat exchangers?

MR. BORTON: I'm sorry, what was the question?

MEMBER BANERJEE: What type of heat exchangers are they, the RHR heat exchangers? Are they just standard shell and tube?

MR. BORTON: Standard shell and tube.

MEMBER BANERJEE: Okay. You don't have a diagram of it around somewhere?

MR. BORTON: We could provide one.

MEMBER BANERJEE: What the internals are. Just a line diagram of some sort; where the flow goes in and out.

MR. BORTON: I'm on Slide 21 now. Once we figured out how to eliminate CAP credit for the accidents, we focused our attention on special events.

In order to eliminate CAP credit for special events, we needed to figure out how to effectively use the condensate storage tank water as additional water inventory source. This had two impacts on MPSH, which I mentioned before.

First, it adds extra water heat capacity, thus, reducing pool temperature, impacting the vapor pressure term. And second, it adds to the height of the pump suction, thus, increasing the suction pressure of the static head turbine.

MEMBER CORRADINI: So again, let me just make sure, so I like your checkbox way of thinking about this, so if the checkboxes with the CST were not there, would the limiting accident change over from the LOCA to an ATWS or an SBO if that improvement wasn't there, or is this just extra margin you're giving yourself? You see my point?

MR. BORTON: With the CST mod?

MEMBER CORRADINI: Yes. If there were no CST mod, would that change what the limiting accident would be or is that just extra margin you guys are giving yourselves?

MR. BORTON: No, this is necessary to eliminate the CAP credit that we currently have.

MEMBER CORRADINI: In Appendix R.

MEMBER BANERJEE: In the Appendix R. Okay. Thank you. Appendix R becomes the dominant --

MEMBER CORRADINI: Well, that's what I wanted to get. Yes. Thank you.

MR. BORTON: To accomplish this goal, several modifications were required. First, we added the standpipe with the CST to prevent draining to ensure an adequate water level. Next, key lock switches were installed in the control room to prevent inadvertent valve movement that could result in swapping the suction from the CST port. And third, we raised the torus high-level set point where swapping the HPCI suction from CST to the pool occurs.

And finally, we made a procedure changes to allow makeup for to the CST from a refueling water storage tank, so those are the modifications that were required for the special events. All these changes, along with the boron-10 enrichment, the standby liquid control system, combined with the other RHR system-type changes we previously discussed, resulted in the available MPSH being above the MPSH required for all special events.

MEMBER BANERJEE: So you know your picture here is very useful in understanding what happened in your previous slide. How does CST affect things? Do you have something equivalent to this picture to sort of guide us through that? I mean, I can see the words, but it's very hard for me to get a feel for what exactly is going on.

MR. BORTON: Yes, I don't believe we created a diagram at all that shows the individual pieces.

MEMBER BANERJEE: Okay. There is no schematic that you have of that.

MR. DICK: This is Michael Dick with Exelon. Kevin, could you go back to the MPSH equation slide? I think maybe that would be --

MEMBER BANERJEE: Yes, if you can just guide me through it, that would be very helpful.

MR. DICK: Okay. So really, what we're looking at is, is this H static term increases due to the CST modification because the RPV makeup source during an accident or an event -- well, let me clarify this, is that the CST is not credited for the design basis LOCA or the small break LOCA, so really, we're talking about the special events. Let me clarify that.

But what it does is, using the CST for the RPV makeup term during the special events, Appendix R, station blackout, ATWS, okay, will result in a larger volume in the torus, or the suppression pool, okay, so that increases the H static term. And then there's actually, then, a small effect because of the CST water being cooler, but the biggest impact, though, is that your H static term increases with this CST modification.

The side benefit, though, of the CST modification is, is that, RCIC and HPCI suction now is credited exclusively during these special events from the CST, and so then since that water is cool, is that there's no impact on MPSH for those makeup systems.

MEMBER CORRADINI: But I guess to ask Sanjoy's question differently, I guess there is a static, but in the prior, maybe I don't remember, or you guys explained it, procedures you weren't planning to use the CST as the makeup for the RCIC or now you're just documenting what you always would have planned to do procedurally? That's what I didn't understand.

MR. DICK: This is Michael Dick again. It was not credited. It was always available in procedurally, but in the accident or in the licensing analysis, the safety analysis was not credited.

MEMBER CORRADINI: Where were you getting the water from?

MR. DICK: From the suppression pool.

MEMBER CORRADINI: Ah, so you were

basically in a recirc mode versus pulling it in from the CST.

MR. DICK: Correct.

MEMBER CORRADINI: Okay. Thank you.

MEMBER SKILLMAN: On Slide 22, please. Would you explain the standpipe to control the volume of CST? I understand all of the other items on that slide, but I don't understand that. How does a standpipe control the volume of the condensate storage tank?

MR. BORTON: So it's actually the volume around the outside of the standpipe. So this standpipe goes to the makeup for the hot well. So it actually allows the CST to retain that volume, and that's about the depth I have on that question.

MEMBER BANERJEE: The standpipe is not within the CST? Yes, it is. So if you raised it, right?

MR. KOVALCHICK: Jim Kovalchick with Exelon. The standpipe is inside the CST at a level which it would protect all the inventory around the standpipe to a certain level, and that standpipe, then, connects to a line that normally is our makeup and reject from the hot well of our condenser. So if the valves in that line were to be affected by a fire, and then spuriously drained or opened uncontrollably, the inventory and the CST would be protected in that event.

MEMBER BANERJEE: So you basically raised that standpipe, is that what happened?

MR. BORTON: That's correct.

MR. MASSARO: And again, that is on the condensate makeup reject line which postulated the Appendix R in one of the scenarios to fail and drain the CST. So the standpipe prevents that draining in that scenario.

MEMBER CORRADINI: Thank you.

MR. BORTON: Okay. So when all these changes are combined for both the accident and the special events, as we discussed, the combined effect was to have a positive MPSH margin for all accidents and events, and thus, we eliminated the need for CAP credit. Let me just move on to the next slide.

As part of the investigation of design, then we also looked at the changes and how they would affect our operations, and I'll turn this over to Jim Kovalchick, who will go through those changes about how this system will then be operated.

MR. KOVALCHICK: Thanks, Kevin. Jim Kovalchick, Exelon Peach Bottom operations. And in discussing changes that we would need to make for EPU and eliminating CAP credit, I can make a general statement that EPU, including changes to eliminate CAP credit, will not cause us to change the basic strategies of our abnormal operating and emergency operating procedures.

In the case of the DBA LOCA with the diesel failure, there will be a new time critical action to use the RHR cross-tie and HPSW cross-tie to align an RHR pump through two heat exchangers with two high-pressure service water pumps in service. These steps will be accomplished through system lineup procedures as specified by our EOPs that are already specifying maximizing containment cooling.

The one-hour time requirement to complete the cross-tie lineup steps will not be a significant operator challenge because the original assumption that no actions are required during the first ten minutes has not changed, and all the actions are from the main control room at a level of complexity consistent with the existing steps in the EOPs.

MEMBER BANERJEE: So as long as they're done within an hour, it's fine.

MR. KOVALCHICK: That's correct.

MEMBER BANERJEE: You could take a full hour.

MR. KOVALCHICK: That's correct. For the specific events of ATWS and Appendix R fires use of HPCI and RCIC was suctioned from the CST is already specified as the preferred source in our procedures. And procedure steps to makeup to the CST during transient response already exist. For EPU, these existing actions just become acquired from an analysis standpoint.

MEMBER SKILLMAN: In three of the four sub-bullets under the first bullet are start, that's a command, open, that's a command, open, that's a command, the next one is balance, that means adjust. Speak to us about what the operators must do to achieve intended balance.

MR. KOVALCHICK: Yes, we've added, or will be adding, and if you look, Kevin, if you could point to them, you see the new motor-operated valves prior to upstream of the heat exchangers, those are drag valves that can be used, and that's specifically part of their design, to throttle the flow. We're also making sure that we have the proper instrumentation of flow for the operator available to do that.

MEMBER SKILLMAN: And those are the FEs that we see on the right?

MR. KOVALCHICK: That's correct. And all

again, those actions are from the control room.

MEMBER BANERJEE: Does that mean you, roughly, keep the same flow going through the -- looking at those FEs? Is that what you mean by balance?

MR. KOVALCHICK: Yes.

MEMBER SKILLMAN: Cavitation downstream of your valves; your drag valves? What consideration has been given to that, please?

MR. KOVALCHICK: We only have a drag valve in the system. We're restricting the orifice with a drag valve on one of the loops, but we already actually have drag valves there, and that's where, between that and the heat exchanger, most of the head loss for the RHR systems are. So this doesn't really represent a new, you know, vulnerability to cavitation.

MEMBER SKILLMAN: What consideration has been given to cavitation caused by the drag valve to the tube bundles?

MR. KOVALCHICK: I would have to refer back to the original design. As I said, there was already a drag valve there and there is no cavitation vulnerability. Tony, go ahead.

MR. HIGHTOWER: So this is Tony Hightower from Peach Bottom. Just, in addition, engineering, through the course of developing this modification, did do a hydraulic analysis for the entire flow path, that included the heat exchangers. The drag valves, based on their nature, do offer an advantage with their distributed pressure drop over the length of their disc to lessen the impact of cavitation, but they did do a hydraulic model that looked at potential cavitation effects throughout that heat exchanger suction and discharge line, all the way up to the vessel, and determined that it was satisfactory as far as the modification process.

MR. KOVALCHICK: Thanks, Tony. Does that answer your question, sir?

MEMBER SKILLMAN: I'd ask you one more question. After the modification is completed, and you actually test it, do the heat exchangers sing? Those of you who have worked in plants as I have know exactly what I'm talking about. If you adjust the drag valve, and the throttle, and all of a sudden your heat exchangers are buzzing because the tube's excited.

MR. KOVALCHICK: We have operational history of throttling the drag valves. We use the drag valves, for example, to limit flow during refueling operations, and we'll bring those down all the way to, I think the low limit, Tony, is, it's 4000 --

MR. HIGHTOWER: 4000 gallons per minute.

MR. KOVALCHICK: -- gallons per minute, which is significantly lower than the high end. And during that range, we have not had issues with flow stability or --

MEMBER SKILLMAN: That's where you're taking your peak delta-P across the throttles, and therefore, the cavitation would be greatest at the tail end?

MR. KOVALCHICK: Yes. That's correct.

MEMBER SKILLMAN: Okay. Thank you.

MR. KOVALCHICK: You're welcome. Okay, Kevin. Okay. So really, this is our conclusion slide for the CAP credit.

MEMBER BLEY: I wanted to follow-up on what Mike Corradini was asking before. What he was really getting at was, although we've been very interested in CAP all along, the scenarios in which you'd need CAP and it wouldn't be there are pretty darn unlikely scenarios. Did you rerun your probabilistic risk assessment, I notice that we didn't see Greg Kruger here today, but he went out with us when we were up at the plant, did you run that under this modification to see if there are any other scenarios that might be more likely for which these changes wouldn't be a benefit that could cause a problem, and none come to mind for me, but did you actually do that?

MR. BORTON: Yes, this was part of the analysis that was done for PRA, and the analysis showed that the CAP credit did not impact, you know, significantly, any of the --

MEMBER BLEY: Formerly successful scenarios.

MR. BORTON: The additional redundancy and the availability, actually, was a positive thing also in the PRA.

MEMBER BLEY: Okay. That's what I would expect. Most studies we've done, this is what I was mentioning -- it's nice to have them separated in case you have some insul, but if you need to be able to cross connect things that, usually, is a net benefit.

MEMBER CORRADINI: I guess I was just curious about system interactions, so if everything's better, that's good, and then I'm curious about, but you guys have already considered that, what things rise and fall in terms of what's important when you go beyond the design basis.

MR. BORTON: It was a balancing act. I mean, the whole approach to elimination of CAP with the modifications that were put in, with the operator actions, you know, so we did go back and forth with a number of different types of options as well that we eliminated because they were not as viable in the situations.

MEMBER CORRADINI: So I'm not an operator, so are the operator actions more complex now or are they simplified because of all this? I mean, that's the other thing that would, at least I'd ask, which is, given that you've done all this, is the operator more challenged to do the right thing in the right timing, or are things simplified?

MR. BORTON: I'll ask the operator.

MR. KOVALCHICK: No, I would consider them neutral change with respect to complexity. You know, they're actions that will need to be taken, but where they're taking the actions, the level of complexity of those actions, it isn't really going to be something that's now like a diagnosis burden. You know, there's not a lot of, like, hey, go do this now, kind of thing, and rush and race, you know, so I consider them a neutral.

And the impact on the overall strategy, we didn't change the EPG implementation nor ELPs.

MEMBER CORRADINI: The only other thing that, again, it's kind of in the conclusion part is, we're not there yet, but in the implementation of a potential rule relative to venting, I assume that's simplified substantially now that you don't need CAP credit. That was my impression.

MR. KOVALCHICK: That's right. It would, overall, expand the flexibility to do it at certain times.

MEMBER CORRADINI: Okay.

MEMBER BANERJEE: So the operators have to open some valves and things like the MOVs.

MR. KOVALCHICK: That's correct.

MEMBER BANERJEE: And the most complex act there is the balancing? So if they're not able to balance the flow to something, is there any --

MR. KOVALCHICK: I don't anticipate an issue.

MEMBER BANERJEE: Is there problem that it poses on balance so you can't get them balanced?

MR. HENRY: I mean, there was a sensitivity study done that showed that, you know, nominally, 4300 gpm per heat exchanger is what we're aiming for, but we could have a mismatch up to 600 gallons and not have an issue.

MR. HIGHTOWER: So this is Tony Hightower from Peach Bottom operations, we're currently developing the procedures for balancing flow. The analysis assumes that we have a minimum of 4300 gallons per minute through each RHR heat exchanger, and that that minimum flow value, it assumes that flow is balanced. If we have flow in excess of 4300 gallons per minute, there's no minimum delta between the RHR heat exchangers and the two trains that we're using.

So in the vast majority of cases, there will be no limitations as far as balancing flow. Operators will be able to maintain flow, approximately equal, in the two heat exchanger trains without an undue burden to balance heat exchangers. So our RHR flow rates will primarily be driven by the net positive suction head that is available at the time. Does that answer your question?

MEMBER BANERJEE: Time to digest that. Okay. Let me reflect. I'll talk to you offline.

MEMBER RICCARDELLA: You stated earlier that there was some unique features at Peach Bottom that made this modification possible, or at least facilitated it, could you expand upon that?

MR. BORTON: It was really the number of heat exchangers. We have four heat exchangers per units. A lot of BWRs only have two heat exchangers for flow pumps. So we have that availability within those loops to have additional heat capacity leak across using one pump per heat exchangers.

MEMBER RICCARDELLA: Thank you.

CHAIR REMPE: Well, we're scheduled for a break at 10:30, and we're ahead of schedule, so if it's -- because we might get behind later today, if it's okay with you, just keep going, if that sounds good to everybody else?

MR. MASSARO: Sounds good. Before Dave starts, I would like to clarify a response that I made earlier in response to a question about our experience with installation of the mods. I mentioned that none of them needed to be installed in the last refueling outage. In the result of our analysis we did find that the supports for the main steamlines were not evaluated for turbine control valve fast closure, and so we were compelled to go put that modification in on Unit 3 in the last outage and it has been completed. I just wanted to make sure I was clear on that.

MR. AINGER: I had some follow-up. This is Ken Ainger with Exelon. I just wanted to answer some follow-up questions. Mr. Corradini, you were asking about how we're able to change the K-factor for the RHR heat exchanger, the answer is that it's based on actual performance testing of the RHR heat exchanger, we were able to utilize some of the available margin with no impact to design or operating requirements.

MEMBER CORRADINI: And I guess my second of the question is, empirically now, you guys have shown it, by, you know, some historical performance, do you have any idea -- and I think you mentioned it was, essentially, just conservatism in the original heat exchanger design, is that it, versus, maybe, you guys have improved, somehow, chemistry and fouling just as an integral effect is produced? That was the second part, I think, of --

MR. HENRY: I'd actually say it was two parts. One was the plugging one that we had for the heat exchangers themselves, and what was assumed fouling factors, so based on the historical good performance of our heat exchangers, minimal plugging of any of the heat exchangers, and the historical good performance from the tubes themselves, in addition to the cleaning that we do periodically on the heat exchangers, we've always been above that level and feel that it was margins to be had for this modification.

MEMBER CORRADINI: Thank you.

MR. AINGER: Mr. Banerjee, another follow-up question you had about how long do we take credit for the containment accident pressure, the answer is greater than 14 hours in our analysis.

MEMBER BANERJEE: Currently. And that's the large break flow curve.

MR. AINGER: Yes.

MR. HENRY: We did talk about the heat exchanger. I don't know -- let me just give you a verbal description of the heat exchanger, so it's a high-pressure service water entering the top of the heat exchanger, there's a baffle plate that directs all the flow down half of the heat exchanger into a floating head area, which returns it back up to the other side of the heat exchanger, and then on the other side of the tubes themselves is the RHR system flow.

MEMBER BANERJEE: So water goes that way.

MR. HENRY: The high-pressure service water will come in and around --

MEMBER BANERJEE: There's a baffle in the middle.

MR. HENRY: A baffle in the middle to redirect it.

MEMBER BANERJEE: And there's sort of U-tubes --

MR. HENRY: It's actually open on the bottom of the heat exchanger. We have what's called a floating head that turns the water and brings it back up. And then on the RHR side, it's just simply on the tube side of the heat exchanger itself.

MEMBER BANERJEE: And the tube side is a U or what?

MR. HENRY: There's straight tubes. Just on the bottom of it, we put a, it's called a floating head, because it floats within the medium --

MEMBER BANERJEE: Oh, I see. I got it.

MR. HENRY: -- so the water will come down into that open head, but it's redirected by pressure up the other side of the heat exchanger. Does that help?

MEMBER BANERJEE: Yes, it helps. And the pressure differential isn't large across the two sides.

MR. HENRY: We have a high-pressure service water system that maintains the service water side higher than the RHR side, and there's an alarm indication for the control room to allow them --

MEMBER BANERJEE: So your shell side is higher pressure than your tube side.

MR. HENRY: Tube side.

MEMBER BANERJEE: It is. How much higher is it?

MR. HENRY: I can't remember the --

MEMBER BANERJEE: Are these heat exchangers vented in the sense that if there's a leak or something, is it needed to vent it?

MR. KOVALCHICK: Normally, it's all closed.

MEMBER BANERJEE: It's all closed.

MR. KOVALCHICK: That's correct.

MEMBER BANERJEE: Imagine the tubes develop leaks if there's a -- what is the pressure differential?

MR. HENRY: If we actually had a tube leak on the heat exchanger during an accident condition, the high-pressure service water system would leak into the RHR side of the system, so the clean water would leak into the potentially contaminated. Clean, in terms of ultimate heat sink water. Raw water.

MEMBER BANERJEE: Well, what is the pressure differential?

MR. KOVALCHICK: Tony, can we get that looked up in an hour? Thank you. We'll get that for you.

MEMBER BANERJEE: The reason I'm asking is, there's been a lot of petroleum industry issues which have arisen with pressure differences between the shell side and the tube side recently, many with off-shore operations, so I'm sort of interested in knowing what that amount is.

MR. HENRY: It's not a significant DP.

MEMBER BANERJEE: Yes, if it's not a significant DP, it doesn't matter.

MR. HENRY: We'll get the average and they do have an alarm that tells them that they need to make adjustments to flow to maintain that positive DP.

MR. KOVALCHICK: And, for example, LPIC mode, we wouldn't even have HPSW on, so the shell side would be higher than the tube side in that case.

MEMBER BANERJEE: Okay. Well, just give me that number.

MR. KOVALCHICK: We will.

MEMBER BANERJEE: Thanks.

MR. AINGER: Kevin, I got one more, this is Ken Ainger from Exelon. Mr. Skillman, earlier, you were asking about the condition of our main steam piping that Mike had referred to in connection with the modifications, and the answer to your question is that, our main steam piping is included in our ASME Section 11 in-service inspection program, and inspections are performed on selected piping supports refueling outage. No deficiencies in this piping have been identified in the last two refueling outages.

MEMBER SKILLMAN: Thank you.

MEMBER RICCARDELLA: I would assume

they're also part of your FAC program.

MR. HENRY: They are included in our FAC program.

MEMBER RICCARDELLA: Which is separate from the --

MR. HENRY: Which is separate from -- I mean, we're talking supports, which is part of the technical specifications for snubbers, and supports, and hangers, and then on the flipside, for the piping side, they are in our FAC program based on its susceptibility to FAC. Ken, anything else? Any other follow-up?

MR. AINGER: That's it.

MR. HENRY: Thanks. Again, I'm David Henry from Exelon. I'll direct you to Slide 26. I'm here to talk about the effects of the extended power uprate on transient and accident analysis, and I'll include the containment response. From a transient perspective, it's important to point out that the limiting transients are evaluated in a cycle-to-cycle basis, allowing for changes to be made in core design or operating patterns to maintain or improve thermal limit margin.

From a sensitivity perspective, the increased power level was shown to have minimal effect on either the limiting pressurization event, which, for Peach Bottom, is the load reject with no bypass or the limiting non-pressurization event at the rod withdrawal error. At EPU conditions, both events produced a delta CPR of 0.27, which is the current delta CPR for Unit 2 and in line with our normal historical performance.

Additionally, for the rod withdrawal error, the delta CPR is dependent on the rod block monitor set point, which can be adjusted if margin to the non-pressurization events is required. Also, for the transient and accident analysis on a cycle-to-cycle basis, the MSIV closure with APR and flux scram was analyzed to verify peak pressure of 1325 and the steam done is not exceeded. This was run at EPU conditions and verified to be within limits.

From an accident response at EPU conditions, as we mentioned earlier, the most limiting event for peak clad temperature is the small break LOCA. Utilizing a safer gesture prime, the peak cladding temperature remained below the 10 CFR 5046 acceptance criteria of 2200 degrees.

For non-LOCA conditions, the control rod drop accident will remain bounded at EPU conditions. Peach Bottom control rod patterns conform to the bank position withdrawal sequence requirements, which limits the control rod worth of any control rod. Results show that the peak fuel enthalpy was 162 calories per gram versus the acceptance criteria of 280 calories per gram.

One item to note, in order to accommodate the increased power level and the associated increase in LOCA source terms, all the leakage in the assumed failed main steamline was decreased by a factor of 1.2, and that is reflected in our technical specifications.

From a containment response, due to the benefits that Kevin mentioned earlier, the peak suppression pool temperature is reduced for all design basis events. Only in the special event of SBO did the temperature increase slightly, but remain below our established limits. Additionally, while both the suppression pool and drywell shelf pressures and temperatures increased slightly, all established limits are met at EPU conditions. Any questions on that slide?

I'll move you on to the flow-induced vibration and structural analysis section. The first slide is on Page 28. This portion of the presentation will discuss the impact of the increased flow rates and what they'll have on the plant system and components.

As shown on this slide, multiple systems are affected by the power increase, either directly proportional, as is in the case for main steam and feedwater, or multiple, as the case is for extraction, steam, and heater drain.

To evaluate this change, the various piping systems were reviewed through multiple means. First were the components that protrude into the flow system, such as thermal wells or sample probes, failure from high-cycle fatigue through flow-induced vibrations or vortex shedding frequencies were evaluated.

Both qualitative and quantitative analysis were performed to identify susceptible components that required remediation. This review did identify thermal wells that will require upgrading prior to EPU conditions. These were done on Unit 3 during the last outage and will be done on Unit 2 in the upcoming outage.

Similarly, for small bore cantilevered branch connections, analysis indicated a potentially low natural frequencies, and some of the main steam and feedwater piping warranted modifications to prevent line fatigue failures. These modifications include tying back the branch line to the actual pipe to couple it with the pipe itself, replacing the valves on the branch line with lighter valves to change the vibration spectrum, or on Unit 2, we had two test taps that were installed since the plant was operational for testing that'll be cut and capped because they are no longer required.

Finally, the main steamlines inside both inside and outside containment, including the HPIC steam supply line, the SRV/RV piping to the SRV and RV outlet, and the new spring safety valve, that Mike talked about earlier, were evaluated at EPU conditions for multiple loading events, including the main stop valve closure.

The new piping stresses were combined in accordance with ANSI B31.1 and identified specific upgrades required to maintain our requirements. All these plant modifications that I mentioned either have been completed or will be completed prior to exceeding our current license power level.

I'll move you on to Slide 29. This is our flow-induced vibration monitoring program. In addition to the modeling that was performed and the modifications that were made to the plant, we are looking for confirmation of our expected results and verification of the margin during our startup testing.

From the detailed analysis that were performed, specific monitoring locations and criteria were established for the vulnerable components, including piping inside the drywell.

Allowable displacements and acceleration limits were calculated based on the ASMI endurance stress limits for steady-state vibration per ON-3. Actual EPU vibration levels will be projected prior to exceeding our current licensing thermal power to ensure our proper response as we're coming up in power level. Questions on the flow-induced vibration?

I'm going to move you on to Slide 30. This is RPV and internals. Analysis were performed to evaluate the effects of the increased power level. Since the maximum core flow is not changing for EPU conditions, components that only see core flow were unaffected by the change. For components affected by EPU, test data was extrapolated to 102 percent of EPU conditions.

Vibration amplitudes were also adjusted by the square of the increased flow velocity rates at each of the extrapolated points. These expected vibration levels were compared with the established vibration level acceptance limits which limit the flow-induced vibration alternating stress intensity for austenitic stainless steels and was found to be acceptable.

From a structural side, the EPU conditions bounded by the current design requirements. For the steam dryer, we have performed site-specific analysis and have a detailed measurement and inspection program to verify the structural integrity. Ken will discuss this in detail this afternoon. The fatigue usage factors meet the ASMI code requirements for a 60-year license requirements at EPU conditions.

Our RPV components having a cumulative usage factor of greater than 0.33 that experienced increase flow, temperature, reactor internal pressure differences, or other mechanical load, were evaluated for fatigue and found acceptable. All evaluations confirm that the RPV pressure retaining and internal components remain structurally qualified at EPU conditions.

MEMBER SKILLMAN: How great was the population of those components that had a CUF greater than 0.33? Is that a large population or a small population?

MR. HENRY: It was a small population. There's the feedwater nozzles and safe ends, the reactor recirc inlet nozzle, and Unit 3 only, the outlet nozzle.

MEMBER SKILLMAN: So less than half a dozen.

MR. HENRY: Correct.

MEMBER SKILLMAN: Thank you.

MR. HENRY: Moving on to Slide 31. Compliance with Appendix G is met and the current inspection strategy for the reactor coolant pressure boundary was found to be acceptable. The current PT curves, bounding EPU conditions are actually bound to EPU conditions due to the higher fluence values utilized. Fluence values for EPU are actually less than our current licensing thermal power limits due to change from the dosimetry-based calculation to the implementation of the NRC-approved theoretical fluence calculation methods.

We will continue to perform inspections based on the requirement of the BWRVIP program, which ensure our compliance with the requirements.

CHAIR REMPE: So basically, that you have data now, and that's why at EPU, you're going to have an estimate to a fluence that's lower? Is that what I'm hearing, is that, you have data versus a theoretical method in the old method you were using?

MR. HENRY: We were actually utilizing the new approved methodology, which allows us to have a lower fluence level projected.

CHAIR REMPE: And the reason that there's a lower fluence level is because there's more data?

MR. DICK: Michael Dick, Exelon. The answer is yes.

CHAIR REMPE: Okay.

MEMBER RICCARDELLA: You're part of the integrated surveillance program. Is that what you mean by the BWRVIP program?

MR. HENRY: BWRVIP program, we are. That's correct.

MEMBER SCHULTZ: With regard to the flow-induced vibration effects on the main steam and feedwater piping, for example, you've got a percent increase there, but in terms of actual magnitude, the experience that you anticipate, how does that compare with industry experience to date?

MR. HENRY: I know we anticipated, roughly, a 30 percent increase in vibrations on the main steam and feedwater, for comparison to the industries, I don't have a good value.

MR. BORTON: For EPUs, there's been increases up to about 50 percent, so I checked earlier, but we'll go back and look at the last couple of BWRs, but I'm pretty certain it falls right into the middle there.

MR. HENRY: Do you have that, Ken? Do you understand what the question is?

MR. BORTON: Yes.

MEMBER SCHULTZ: Thank you.

MR. HENRY: All right. I'll turn it over to Jim.

CHAIR REMPE: Let's go ahead and we'll have a closed session after break, if everyone's willing to do it that way. It's more efficient.

MR. KOVALCHICK: Okay. Very good. Again, I'm Jim Kovalchick. I'm an operations manager with Exelon at Peach Bottom assigned to EPU integration, and one of my responsibilities is working with the team on preparing our power ascension plan, so I'll make this presentation and we'll include discussion of our preparations, major testing, and acceptance criteria, except for the reactor steam dryer, which will be discussed in that proprietary presentation.

So moving on to Slide 33, our power ascension test plan was developed using Section 14.2.1 of the standard review plan contained in NUREG 0800. The plan will be implemented using a single procedure that consolidates verification of individual modification acceptance testing as well as integrated plant operation validation.

Many of the modification tests for specific equipment will be performed before plant startup and the power ascension testing plan will ensure those pre-startup tests are completed satisfactorily. Modification equipment testing that requires power operation, such as the new automatic voltage regulator, will also be coordinated through the master procedure.

We're preparing the integrated plant testing using a method recommended in the standard review plan, specifically, we evaluated the applicability of testing done for the original plant startup as well as uprates, and also, any new testing appropriate for changes made since then. As a result, we will test 16 areas from the original startup testing scope, along with wide-range neutron monitoring testing, which didn't exist in 1974, as well as monitoring of the reactor steam dryer, which will be discussed with specifics later.

And I'll pause here for a moment. The wide-range neutron monitoring, given that it's unique to Peach Bottom, I'll explain that that was a modification that we made that is, in a nutshell, a combined source range, intermediate range monitoring of neutrons.

We will implement the power ascension testing using a special organization that includes personnel with station-specific experience in operations, chemistry, radiation protection, predictive maintenance and instrument maintenance, and the organization will include procedure and engineering support.

CHAIR REMPE: In the documentation that we reviewed, you refer to a plant operations review committee that looks at the results at each hold point during the ascension testing occurrence, and who is on the PORC?

MR. HENRY: It's our PORC, or plant overview review committee, that's chaired by the plant manager, and has the directors from all the departments on the actual -- so the operations, maintenance, engineering, work management director, our normal quorums, and then it's the expertise based on --

CHAIR REMPE: Is it, like, 10 people, 15 people?

MR. BORTON: Typically, the quorum is five. Am I correct, Jim?

MR. ARMSTRONG: Hi. I'm Jim Armstrong,

the reg assurance manager, I'm also responsible for the PORC function. Okay. So just a clarification, the PORC is chaired by the operations director, the alternate is the engineering director or myself. Minimum quorum requirements are five people, okay? It is required by tech specs that all plants have a similar function.

CHAIR REMPE: Okay.

MR. BORTON: And as I understand it, the plant manager approves the plans.

MR. ARMSTRONG: Yes. We make recommendations to the plant manager and he approves it or not.

CHAIR REMPE: Thanks.

MR. KOVALCHICK: Okay. Moving on, the next two slides, 34 and 35, show when, within the integrated plant testing, we'll do the specific areas of that testing. Power ascension will be incremental so margins of safety and expected performance can be validated before we move on. I didn't expect to speak to each of the individual areas here, except where the Subcommittee had questions, but a few things that I'll note, control rod drive testing will consist of normal surveillances, including coupling checks for full out rods and single-notch exercise testing through the power ascension.

Testing of turbine stop control and bypass valves as well as MSIV testing will be performed for at least one valve at power level steps to determine the power level for future testing for acceptable plant impact, and also, the MSIV testing, it was a partial closure, not a full closure. And finally, for clarification, portions of tests of the pressure regulator and the feedwater control will not be done where they would tend to raise power above new EPU 100 percent.

MEMBER CORRADINI: So just a logic question, I think I get it, at least generally, but the only thing that you don't test at low power, and then again at high power, is the bypass MSIV and turbine valve testing. Is there a reason why you don't need to do it at 108 or EPU, because I was looking at the other things, and either you're doing at the beginning, at the end, or you're doing it just formally all the way through.

That's the only one I didn't see some sort of consistency.

MR. KOVALCHICK: Yes, I'll explain it again. What I was trying to say there was, for those valve tests, we will perform those until we get to the place in power where we've decided that, okay, that's the highest power that that's appropriate to test. I don't expect that will be 100 percent EPU, for example, and we don't perform those tests at 100 percent current rated power.

So we expect to perform those tests, trend the results, and then determine, okay, this will be what we go ahead and move forward with where we perform normal surveillances.

MEMBER CORRADINI: And again, since I'm not in operations, you use the word appropriate, tell me what the term is appropriate, I forget.

MR. KOVALCHICK: Appropriate will mean that the -- for example, like, the EHC control of the turbine is stable or that level changes are within our normal acceptance that we consider reasonable. And those criteria will be built into the procedure.

MEMBER RICCARDELLA: Regarding the vibration monitoring, I know you have plans for extensive monitoring of the steam dryers on Unit 2, are there other vibration monitors going to be in place during these power ascensions, like, on the piping and other pump monitoring?

MR. HENRY: Absolutely. For both inside and outside containment monitoring the steam lines, feedwater lines, condensate flows, extraction steam probes, the whole section of data that we've been getting that has established links.

MEMBER RICCARDELLA: And the small-bore piping?

MR. HENRY: Small-bore piping also.

MR. MASSARO: To be clear about the vibration equipment that's on the main steamlines, there is vibration equipment there as well, not installed as part of the test startup, you know, similar to the dryer where it's installed and then we'll be taking readings off that. The other areas that Dave's talking about, we will be monitoring for vibration but we don't have fixed vibration sensors in each location.

MEMBER SKILLMAN: Let me build on Dr. Corradini's question about the bypass valves, the MSIVs, and turbine valve testing. It would seem to me that it would be logical to have an MSIV test at a higher power level rather than, approximately, 90. It would seem as you push this plant further, you would want to have assurance that your MSIVs are going to close tightly and stay closed tightly when you command them, for whatever reason that might be.

Why aren't you pushing them at 108, or 105, or something like that? Just giving yourself the assurance that the capability of those valves will do what you want those valves to do?

MR. KOVALCHICK: We're not changing the design of the MSIVs. We know what their capabilities are with respect to flow and pressure now. And also, the design of those valves, steam flow closes them, so there really isn't anything that we would gain from trying to check that at 108 percent of current.

MEMBER SKILLMAN: Well, you would gain the confidence that it will do what you intend it to do, you would also probably have a transient that you might not want to have.

MR. KOVALCHICK: And that's part of it too, you know, that was part of the criteria, was, to go through and what will we gain from it? What would be the impact, for example? And that transient is not one -- and it's been evaluated by PRA. It's not one that we want to take that would potentially have impact on our ability to provide continued generation to -- you know, if there was a transient that would cause the plant to trip.

MEMBER SKILLMAN: So that's really the answer to the question that Dr. Corradini asked, define appropriate. Appropriate is that combination of plant effect and equipment effect where you determine testing on some of these just ceases to be what you want at the higher power level.

MR. KOVALCHICK: Yes, other than we are going to set what we consider appropriate, conservative, well before there would be that effect, but yes, I tend to agree with your premise.

MR. BORTON: And to answer also was, operating experience, we looked at other plants EPU conditions that had an expected occurrences, so that also factors in generically when you're looking at, you know, globally, our ascension plan as well. So we did take a look at experiences at other plants.

MEMBER SKILLMAN: Okay. Thank you.

CHAIR REMPE: So as you go through this decision process, do you have to get any additional concurrence from the regulator or did they approve it initially at this time and that's it?

MR. BORTON: When we submitted our power ascension plan, we'll also provide procedures prior to exceeding current power levels as well as part of our license condition that's being built in.

CHAIR REMPE: But you don't have to ask them about when you can stop the main steam isolation valve testing, for example.

MR. BORTON: That's correct. I mean, the

plan was put in with the constraints that are put into the plant already, so they've evaluated the constraints that we're proposing, and then based on that, we'll get this approved.

CHAIR REMPE: Okay. Thanks.

MR. KOVALCHICK: And I would add too that, one of the other potential benefits when you decide on whether or not you are going to do a test like an MSIV closure, would be whether or not the operators understood how to respond. And in our review, we determined that the simulator modeling and the training that the operators had is sufficient for that as well. So it's not just about the mechanics. We also consider the operational aspects of that as well.

MEMBER SKILLMAN: Thank you.

MR. KOVALCHICK: You're welcome. Okay. Any other questions on Slides 34 and 35? Okay. I'd like now to talk about the acceptance criteria. There are two types of acceptance criteria in the plan. The first is designated as level 1 and it involves design limits. If a level 1 test criterion is not met, the plant will be placed in a hold condition, judged to be satisfactory and safe based on prior testing. And I'll pause here to say that more than likely this would result in a reduction of power to a previous spot in our power ascension.

Resolution will be pursued by equipment adjustments or engineering evaluation. The plant operations review committee, or PORC, must approve corrective actions and applicable test portions must be repeated and results presented to PORC prior to raising reactor power.

Moving on to the next slide. The next acceptance criterion designation is level 2, which is performance expectations. If a level 2 test criterion is not met, an evaluation will be initiated to identify cause and corrective actions, PORC must approve corrective actions, if physical adjustments are required, the test portions will be repeated to verify level 2 requirements are satisfied prior to increasing power.

MEMBER SCHULTZ: Now, in this context, when you say, if there's a problem, then you said, also, that you might then, or likely would be, decreasing power, going to a lower power level to hold while the review would be completed and corrective actions would be taken. Now, when you talk about prior to increasing power, is that above the power where you now sit or is that increasing power above where you were when you ran into the issue?

MR. KOVALCHICK: Above where we now sit.

MEMBER SCHULTZ: Thank you.

MR. KOVALCHICK: If there's no other questions for power ascension, that ends that portion of the presentation.

CHAIR REMPE: Thank you. So at this point, we're going to have our 15-minute break and come back at 10:45, but when we come back, we're going to be in closed session, so this will end the open session. It's my understanding that the staff members that were going to talk at 12:45 will be able to support this a bit early and probably will just go through this first discussion item of the closed session when we come back before lunch. Does that sound good to everybody? Okay. Thank you.

(Whereupon, the foregoing matter went off the record at 10:26 a.m. and went back on the record at 4:19 p.m.)

CHAIR REMPE: This is the public portion, kind of, closeout of the meeting. Is there someone out there in the public who could just say, I'm there, so we could verify the lines are open? Okay. So I guess we're going to assume that there are no members of the public on the phone line, but we do have a member of the public, I believe his name is Mr. Eric Epstein, here today who would like to make comments, and because of time, you do need to limit your comments to ten minutes or less, okay?

MR. EPSTEIN: Sure. Where do you want me?

CHAIR REMPE: Go up to the mic.

MR. EPSTEIN: Good afternoon. I'm Eric Epstein. I'm the chairman of Three-Mile Island Alert. We're a safe energy organization founded in '77. We monitor three nuclear power plants on the Susquehanna River; Susquehanna 1 and 2, TMI 1 and 2, and Peach Bottom 1, 2, and 3. The focus of my comments, and let me be blunt, have to do with omissions rather than commission. I've tracked the process from the beginning and I've participated in a number of the teleconferences.

We're not theologically opposed to the uprate, but we are theologically opposed to uncoordinated regulation, and I think there are a lot of holes in this process, which were similar to the holes we witnessed in the re-licensing of PPL, which resulted in a memorandum of understanding between the NRC and the Susquehanna River Basin Commission.

Our testimony is 29 pages long and I've learned as a professor and a teacher at the end of the day, nobody really cares what you have to say, so I'm not interested in reading the 29 pages. Furthermore, I learned as a teacher and a professor that I just made the cardinal error by handing you a document that you will read and not listen to me.

That being said, I'm just going to point out a couple of the trends that we've noticed, and essentially, what we did is, we outlined the licensing of Peach Bottom, which has been quite an odyssey, and many of you have probably been done there in Southern York County, but I'd just like to remind you, we're talking about a plant that really got off to its start in July 1960.

Obviously, Peach Bottom 1 is done and one of the concerns we have, if you track the trajectory of the construction of the plant, and if you look at the three uprates, because we're at our third uprate right now, the characteristics of the plant have changed dramatically since 1960, which, you know, was a time when Kennedy was President, and I think your predecessor agency actually was the one that reviewed the original licensing requirements, some of which have not been modified, and that causes me concern.

I'm not a real big fan of saying, get back to me later with regulatory mandates. I'm one of those old-school Harry Truman guys that, when you say to me, ten minutes, it means ten minutes. No more, no less. You know, you're looking at a plant that was built with a combined capacity of 2194 megawatts. License for 40 years. It's now re-licensed to operate for 60 years. The mega-wattage is almost 4000. It's a dramatic increase.

This has been a forward process. I've reviewed all the RAIs. I think the last one was January of this year. In fact, the heat sink operability requirements just landed on my desk Saturday. Saturday. They were sent out Friday. So, you know, it's difficult for an organization like ours to, you know, monitor all these trends, but that's kind of late in the game.

And that's not a hit on folks, because I know it's a difficult process. I guess the concern I have is also the fact that Peach Bottom is a closed cooling system and most of my comments deal with environmental impact. And again, if you look at the discussion we have on Pages 6 through 10, thoroughly researched impacts on the Susquehanna River.

And, you know, the river itself is an extraordinary watershed which empties into the Chesapeake Bay, and the last time I checked, that was the most productive estuary in North America. Had a lot of problems since this plant was built with extreme weather events, with flooding, with fish kill, and again, that's enumerated, documented, and cited throughout the document, which concerns me because there was no site-specific evaluation of any of those impacts, either by the SRBC or the DEP.

Which is interesting because, when this plant was built, it wasn't what it looks like now. In other words, right now, you have Muddy Run, you have Holtwood, you have Conectiv, it's an energy park. It's not what it was in 1960. Nothing is. The world changes.

Special attention. I just want to read you a couple things about the Conowingo Pond, because last week, ironically, Holtwood was just re-licensed, 800 megawatts, and FERC had a much more rigorous and aggressive review protocol. In fact, the only that they got a WQ from DEP was based on a settlement, which I'd encourage you to look at. There's no such agreement between NRC and Exelon, SRBC and Exelon, DEP and Exelon, and that's an 800 megawatt plant, about 1/4 the size, owned and operated by the same company.

But I'd like you, when you have a chance, on Page 9, the Conowingo Pond is really the lynchpin to what's occurring here. The other reality is this, and let's be frank, Marcellus Shale is now a player. And when you go to Susquehanna River Basin commissions, almost all the applicants are Marcellus Shale. I don't look for that to end.

So there's a limit to the water. It's also ironic, Peach Bottom is only 36 miles north of Baltimore, and we're talking about a water source that also -- it goes as far east as Chester, the City of Chester, so this is a dynamic, important asset. On Page 11, and I'm sure with this many people here, by the way, everybody seems to have gone to the same tailor, so I think I added a little continuity to the dress attire today.

I would point out the legal arguments that we make, 11, 12, 13, 14, and 15, which were similar to arguments that we've made in the past about illegal fragmentation. Also, the SRBC's rules and regulations have changed. Apparently, that has not been incorporated into the NRC's oversight, which I find deeply disturbing. There's now an Act 220. In fact, if you look at the number of regulations that have been promulgated, passed, adopted, and are now statute in Pennsylvania, 1990, 2000, 2014, it's a whole new aggressive, rigorous protocol.

So one of the things that really completely dismays me is that we're grandfathering in the MPDES and conditioning it based on requirements to occur down the road. I just don't think that's any way to run a business. DEP exempted Peach Bottom from an environmental impact statement. And again, you know, based on our research, the EIS that was concluded was 1973. I think Nixon was still President.

And if you look at the statutes that have come along since re-licensing in Pennsylvania, Radiation Act, Chesapeake Bay Commission Agreement Act, Hazardous Site Cleanup Act, Pennsylvania Environmental Stewardship and Watershed Act, Act 29, Act 220, these things just can't be taken out of the mix because it's inconvenient, arduous, or takes a lot of time.

Also, I don't see any clear-cut continuity between 316(b) and the implementation of the EPU. That's 12.4 percent. It's a lot. With the other increases, this is a new plant with new characteristics. I ignored 316(a), although I still think 316(a) has a part to play here. Also, the PUC was not consulted regarding Title 66, and that has to do with the cost of water.

And that argument is outlined again on Page 14. So everything, you know, I'm hoping, you know, that I'm articulating today in a really short and brief format has been documented, and I'll hope you'll give it some time to look at it. I think the major concern we have and the takeaway we'd like you to come away with, there's a lot of open issues, there's a lot of generalizations, there's a lot of vagaries.

I'm a former professor of history and I really am a stickler for facts, so some of the language, maybe that's your nomenclature, gives me pause for concern. I didn't really see any empirical data to support environmental impact conclusions that were also absent an environmental impact statement. And, you know, I'm a little troubled that you would ignore the aggregate impact of the EPUs.

I especially focused on the aquatic resource impact and I just want to read you something, and a lot of that is based on ongoing studies or studies to be completed after you approve the EPU, which, I don't get that regulatory protocol. This is from the Conowingo Pond. "The conclusion was made assuming at station conditions under the MPDES. After the study is completed and based on the study results, Exelon will submit to the PDP, an application to modify the MPDES. For any future modifications, the GDAP" -- I guess that's where it kind of sticks in my craw is, how do you approve an EPU? How do you approve a license amendment request on a condition that has yet to be met, on a promise that may or may not be kept?

Again, looking at what we did, and I don't want to get into it, a lot of aquatic challenges, not just with algae blooms, not with invasive species, I mean, there's tons. The river has changed. And if you know the river, and you start at Susquehanna, you go down to TMI, you go down to Peach, you can't have it both ways. Exelon can't come in here and say, we're going to delay our flooding compliance for a year to 2015 because we now want to coordinate with TMI, and then ignore regional coordination.

The zebra mussels, the Asiatic clams, all that, you know, they're a reality, whether or not they'll impact Peach Bottom, I don't know. Asiatic clams certainly have at TMI. I direct your attention, actually, to about Page 22. These are miscellaneous. I don't know, if you read this document, it's as if the States of Maryland and Delaware don't exist.

I mean, we're less than two miles from the Maryland border. I find that interesting. The census data is four and a half years old. I understand. Also, it looks like you completely bypassed the York County Planning Commission, which is dedicated to doing what you were supposed to do, and that's a socio-economic impact statement.

I don't think the U.S. Fish and Wildlife Service was consulted. I may be wrong. I didn't see anything from the U.S. Army Corps of Engineers. I didn't see anything acknowledging that Peach now accepts radioactive waste from Limerick. So the characteristics of the plant, much, much different. It's a fluid situation.

And I would just conclude by saying in my summary, our summary's in the back, that I just don't think it's good regulation to leave open-ended commitments to a time to be determined. I actually, frankly, think that's awful. And I think one of the problems, and I don't think this was intentional, is there needs to be better coordination with the SRBC, the Pennsylvania Fish and Boat Commission, the PHMC, I mean, just a whole slot of agencies.

The fact that DEP gave them a free pass, I don't think is an answer unto itself. So I think I'm in under ten?

CHAIR REMPE: You made it. Thank you very much for your comments. Is there anyone else in the room who wanted to make a comment? Okay. So this is a Subcommittee meeting, and at the end of Subcommittee meetings we usually go around the table and ask for final comments from the Member, and because of a plane commitment, I'm going to let Kord Smith go first.

DR. SMITH: I'm afraid that most of today's discussion was a little bit outside of my area. I'm hoping we hear back on MELLA Plus, it'll weigh-in a little more heavily in my area. I saw nothing that caused me a safety concern today.

CHAIR REMPE: Okay. Thanks. Mike, did you have any comment?

MEMBER CORRADINI: I don't have any further comments. I've commented throughout the day. I think from the standpoint of our discussion, both in open session, closed session, and really closed session, I do think the generic issue of consistent steam dryer analysis that we understand and can feel good about is probably the only thing that I'd repeat.

CHAIR REMPE: Okay. So, Dana, you've been here a short period of time, but do you have any comments?

MEMBER POWERS: Well, I did have a chance to look through some of the view graphs. I've seen we addressed CAP.

CHAIR REMPE: Yes.

MEMBER POWERS: I congratulate you. I

think that is a real major step.

CHAIR REMPE: Okay. So, Steve?

MEMBER SCHULTZ: The general comments I have is that, with regard to, I'll, echo what Mike said, and also what Dana said with regard to CAP, but I would also further comment that there's a substantial number of plant modifications that go, in fact, beyond what's required for the EPU, and I think incorporating them into this work is a very important initiative, and I'm glad to see it.

Appreciate the presentations today, especially, and with regard to the technical reviews that we heard about from the staff, their technical reviews of the application with regard to their evaluations that we heard about today were very thorough and well presented. I thank the staff and the applicant for the presentations that we've heard.

MEMBER BLEY: The only thing I would add, and it isn't directly relevant to the decisions we have to make later, is the discussion about CAP, the interest in side effect, which doesn't surprise me that the features they've added to ensure CAP is not a problem are doing them good in other areas where it's probably much more likely to be helpful in terms of the flexibility they're getting to respond to other situations, so I found that interesting.

CHAIR REMPE: Dick?

MEMBER SKILLMAN: I thank the staff and the Exelon team for a thorough presentation. The treatment of the dryer analysis and practical issues to me was thorough and convincing. The fact that they were codes that take into consideration thermal conductivity, degradation for accidents and AOOs gives me comfort. I had a number of issues that I was concerned about relative to the plant modifications and through the course of the morning, and through the afternoon as well, those concerns were address, so thank you.

CHAIR REMPE: Okay. Sanjoy.

MEMBER BANERJEE: First, I'd like to thank the staff and the applicant. I think they all made really good presentations. Of particular note is, of course, how innovative they were in dealing with CAP, which I really appreciated, and I think the whole Committee did. It shows us that even though it's somewhat plant-specific, that if somebody really wants to do it, they can often do it.

And this was a point that Dave Bassette, many years ago, who was one of our staff members, pointed out to me, actually, and to several of us that, one of the ways to deal with CAP was to actually improve the amount of heat removal so you could cool down the fluid in the torus, and he showed something fairly similar to this, so I'm glad that somebody is actually doing this now. So that's really a big step forward.

And with regard to the other major issue, which is steam dryer, I think with regard to the dryer, there's enough empirical evidence, based on the performance of the Nordic plants and other plants that this dryer seems to be robust and should work. There are issues that we still need to resolve, and whether this be done on a generic basis and what impact it can have here, I don't know, but it's something that we, as a Committee, will need to consider in the future.

So with that, I don't know how it will affect the letter, whether it should simply be noted there or some other point should be made, so otherwise, it's fine.

CHAIR REMPE: Okay. Pete.

MEMBER RICCARDELLA: Yes, you know, my area of expertise is structural analysis, and so I had particular interest in their replacement steam dryer work. I think that there's been a significant amount -- you presented a significant amount of analysis and testing, and I think you have a power ascension plan that is well thought out and that, plus the associated license conditions on the power ascension plan, I agree with the staff conclusions that there's reasonable assurance that the steam dryers will operate within structural limits.

CHAIR REMPE: Okay. Yes, Dick.

MEMBER SKILLMAN: I have one more. I want to thank Eric for making the trip from Harrisburg and for his courage to speak. Thank you.

CHAIR REMPE: I didn't share the appreciation that you have worked hard to eliminate CAP. I went to look in a little bit more about some of the assumptions that differed in the analysis to justify that, and again, I'll do a bit more homework, but it's still not entirely clear in my mind, but I think it's something that I just need to make sure I understand a bit more.

With respect to the full Committee meeting, there will be, probably, at most, two hours for the discussion, and so clearly, focus your presentation, I think, on the most important issues, the CAP elimination, and the steam dryer, and some notice of the upgrades that are occurring. Are there any other things that individuals on the Subcommittee would suggest should be presented to our colleagues on the full Committee?

And with that, is there anything the staff wanted to say as a follow-up? Then I think we can close the meeting. Thank you again.

(Whereupon, the meeting in the above-entitled matter was concluded at 4:38 p.m.)

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

ACRS Subcommittee on Power Uprates

NRC Staff Review of Extended Power Uprate for Peach Bottom Atomic Power Station Units 2 and 3

June 10, 2014

Opening Remarks

Louise Lund

Deputy Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Background

- 154 power uprates approved:
  - 29 are extended power uprates (EPUs)
  - 18 of 29 are for boiling-water reactors (BWRs)

- Peach Bottom Proposed EPU:
  - 3514 to 3951 Megawatts Thermal (MWt)
  - 12.4% increase

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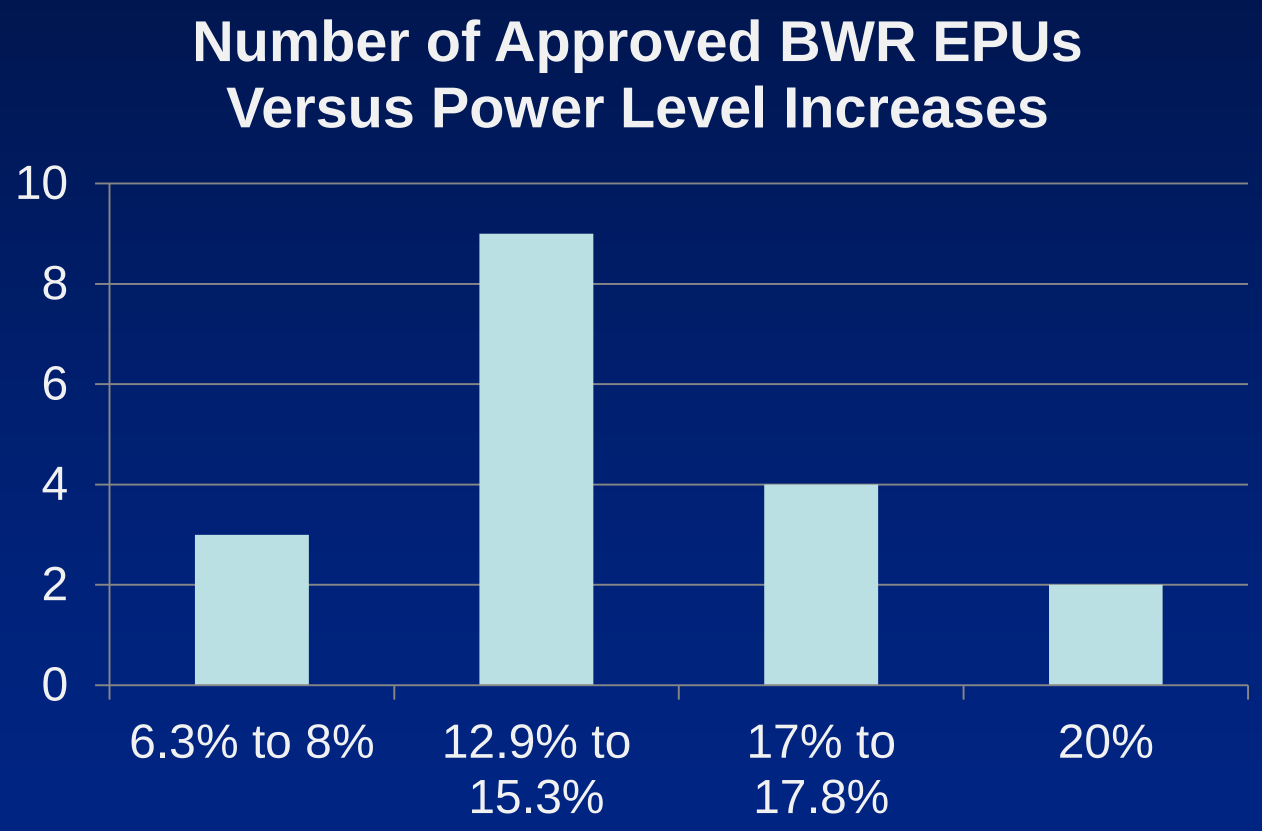
Comparison to other BWR EPUs



Peach Bottom EPU Review

- EPU Review done with Review Standard RS-001:
  - RS-001 safety evaluation template modified to reflect Peach Bottom design and licensing basis
  - RS-001 used for 17 EPUs since 2005

- Review has involved:
  - Over 25 reviewers
  - 9000 hours

Introduction

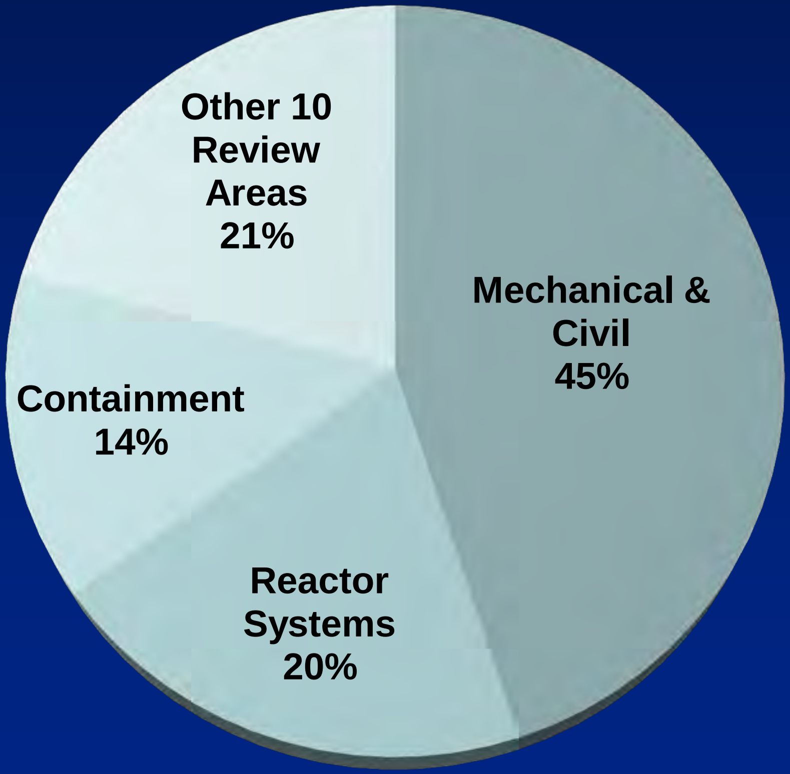
Rick Ennis

Senior Project Manager
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Review Timeline

- September 28, 2012 – Application submitted to NRC.
- December 18, 2012 – NRC informs Exelon of need for supplemental information.
- February 15, 2013 – Exelon submits supplemental information.
- March 8, 2013 – Application accepted by NRC for review.
- September 8, 2014 – NRC forecast for review completion based on 18 months from date of acceptance.

Requests for Additional Information (RAIs)



Topics for Morning

- EPU Overview
- Transient and Accident Analyses Summary
- Flow-Induced Vibration & Structural Analyses
- Power Ascension

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Topics for Afternoon

- **Nuclear Design & Safety Analyses**
- **Containment Analyses**
- **Replacement Steam Dryer Overview**
- **Steam Dryer Analyses**

Peach Bottom Atomic Power Station Extended Power Uprate

Advisory Committee on Reactor Safeguards

Meeting of the Subcommittee on Power Uprates

June 10, 2014

Exelon Generation

Introductions

Peach Bottom Atomic Power Station (PBAPS) Extended Power Uprate

Agenda

- Introductions
- EPU Project Overview
  - Background
  - Parameter Changes Summary
  - Modification Summary
  - Elimination of Containment Accident Pressure (CAP) Credit
- Transient and Accident Analyses Summary
- Flow Induced Vibration and Structural Analyses
- Power Ascension
- Replacement Steam Dryer Overview
  (afternoon closed session)

Exelon Generation.

Key Team Members Present

- Kevin Borton - Power Uprate Licensing Sr Manager
- Craig Lambert - Power Uprate Vice President
- Mike Massaro - PBAPS Site Vice President
- John Rommel - Power Uprate Engineering Director
- Ken Ainger - EPU Project Management Director
- Jim Armstrong - PBAPS Regulatory Assurance Manager
- Dave Henry - PBAPS Sr Manager Design Engineering
- Jim Kovalchick - PBAPS Sr Manager Operations, EPU Integration
- Tony Hightower - PBAPS Operations Shift Supervisor

PBAPS EPU Team

The EPU Project Team is staffed with personnel having extensive BWR plant and EPU experience:

- Exelon
  - Combination of Dedicated Project and Station Resources
- GE-Hitachi (NSSS)
- Sargent & Lundy (BOP)
- Industry EPU experienced specialty contractors

Standard Application

EPU License Application

- Based on GEH Topical Reports
  - NEDC-32424 (ELTR-1)
  - NEDC-32523 (ELTR-2)
  - NEDC-33004 (CLTR)
  - NEDC-33173 (IMLTR)
- NRC RS-001 Format "Review Standard for Extended Power Uprates"

Exelon Generation

EPU Project Overview

Background

Parameter Changes Summary

Modification Summary

Elimination of Containment Accident Pressure (CAP) Credit

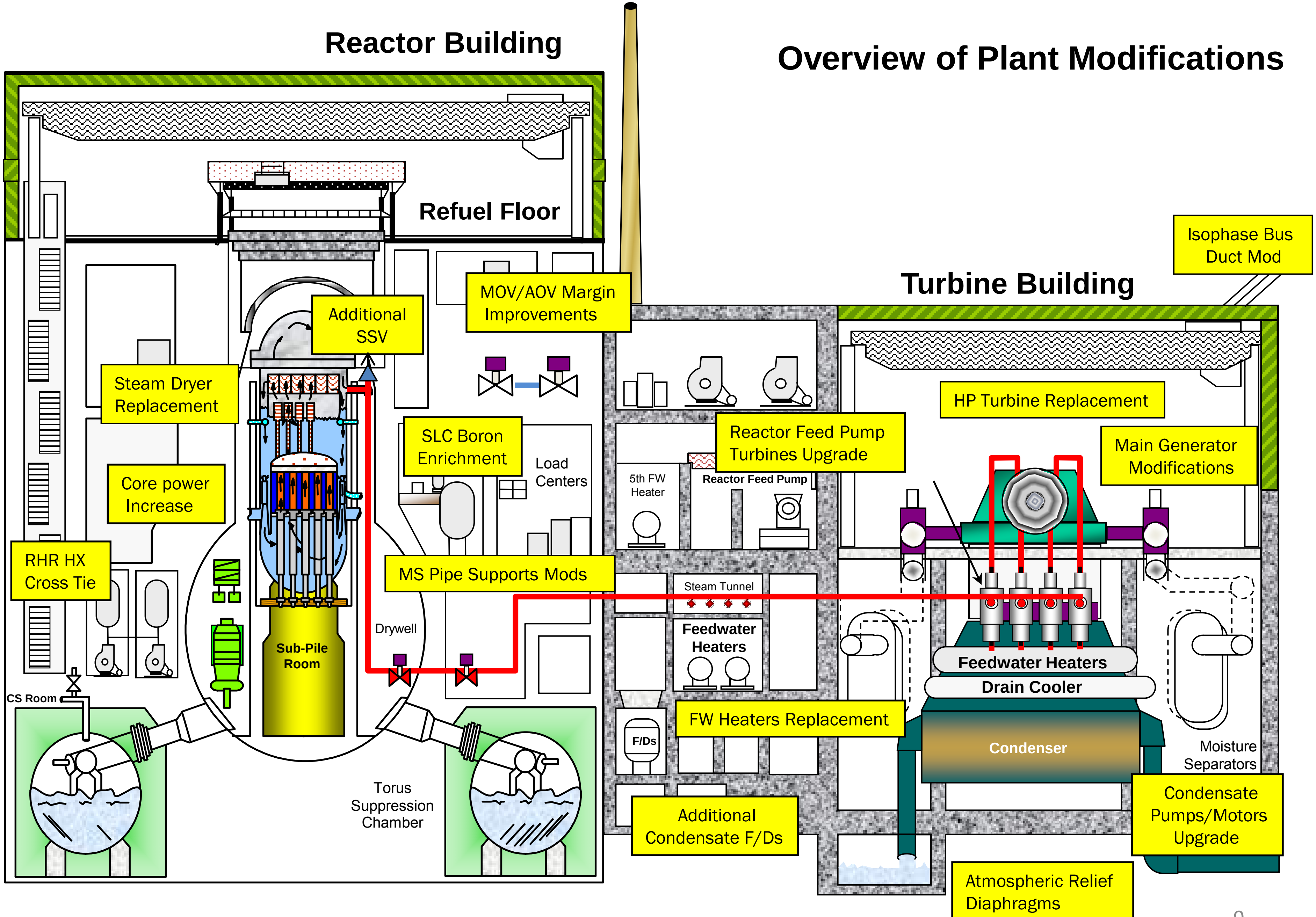
Peach Bottom Atomic Power Station Overview

- GE BWR 4 Mark I Containment
- Operating License issued 1973 (U2) and 1974 (U3)
- Commercial Operation commenced 1974
- Renewed License issued in 2003 (U2 and U3)
- Licensed Thermal Power History
  - Original Licensed Thermal Power (OLTP) 3293 MWt
  - Stretch Uprate in 1994 and 1995 3458 MWt
  - MUR power uprate in 2002 to CLTP 3514 MWt
  - Proposed EPU (20% OLTP, 12.4% CLTP) 3951 MWt

Parameter Changes Summary

Parameter	CLTP	EPU
Core Thermal Power (MWT)	3514	3951
Licensed Full Power Core Flow Range (Mlbm/hr)	84.87 to 112.75	101.48 to 112.75
Licensed Full Power Core Flow Range (% Rated)	82.8 to 110.0	99.0 to 110.0
Steam Dome Pressure (psia)	1050	1050
Vessel Steam Flow (Mlbm/hr)	14.387	16.171
Feedwater Flow Rate (Mlbm/hr)	14.355	16.139
Final Feedwater Temperature (°F)	381.5	381.5
CAP Credit Required (psig) (DBLOCA)	6.1	CAP not credited

Overview of Plant Modifications



Major Modification Summary

Modifications to Improve Reliability and Operating Margins

Additional Main Steam Spring Safety Valve (SSV)
One additional SSV on each unit
Increases margin for ATWS analysis at EPU

Replacement Steam Dryer
Replacing steam dryers to improve structural margin
Improves Moisture Carryover (MCO) performance lowering in-plant radiation doses

High Pressure Turbine Replacement
Accommodates increase in steam flow at EPU
Improves operating margin for Main Turbine Control system

Reactor Feed Pump Turbine Upgrades
Accommodates higher blade stresses at EPU
Improves reliability

Major Modification Summary

Modifications to Improve Reliability and Operating Margins (continued)

Feedwater Heaters
Five replaced (1 on U2 and 4 on U3) to restore margin at EPU conditions
Other FW heaters analyzed and verified to be acceptable for EPU

Reactor Water Cleanup
Flow diffusers to be installed on all four RWCU demineralizers
Improves efficiency to maintain chemistry limits at EPU conditions

Condensate Pump/Motor Upgrades
Impellers to be replaced and larger motors installed
Improves margin at EPU conditions

Condensate Filter/Demineralizer
Two additional demineralizers to be installed on each unit
Maintains chemistry limits and operational flexibility at increased FW flowrate at EPU

Main Steam Piping
New supports and support modifications
Assures margin to Code requirements at EPU conditions

Major Modification Summary

Modifications to Improve Reliability and Operating Margins (continued)

Main Generator Modifications
U3 rotor replaced in 2013, U2 rotor to be modified for new rating
Restores generator margin at higher MVA at EPU

Isophase Bus Duct
Several portions of existing IPBD will be replaced
Restores IPBD margin at higher MVA at EPU

ATWS-Recirculation Pump Trip
The ATWS-RPT relocated from MG sets to Recirculation Pump motor breaker
Provides faster coastdown time for Recirculation Pumps to support ATWS analysis

Motor Operated Valves
MOVs affected by changes in EPU response were evaluated
Improves margin at EPU conditions

Major Modification Summary

Modifications Associated with CAP Credit Elimination

RHR Heat Exchanger Cross-Tie
Includes new cross-tie valve allowing two HXs to be supplied from one RHR pump
Increases RHR heat removal capability

HPSW Cross-Tie
Replaces existing cross-tie with valve able to open against full flow differential pressure
Increases RHR heat removal capability

Condensate Storage Tank
Provides protected CST volume and safeguards against fire-induced swapover to torus
Allows crediting of CST as suction source

Standby Liquid Control System
Boron-10 enrichment increased to 92 atom percent in SLC Storage Tank solution
Lowers Suppression Pool temperature during ATWS

Exelon Generation.

Elimination of Containment Accident Pressure Credit

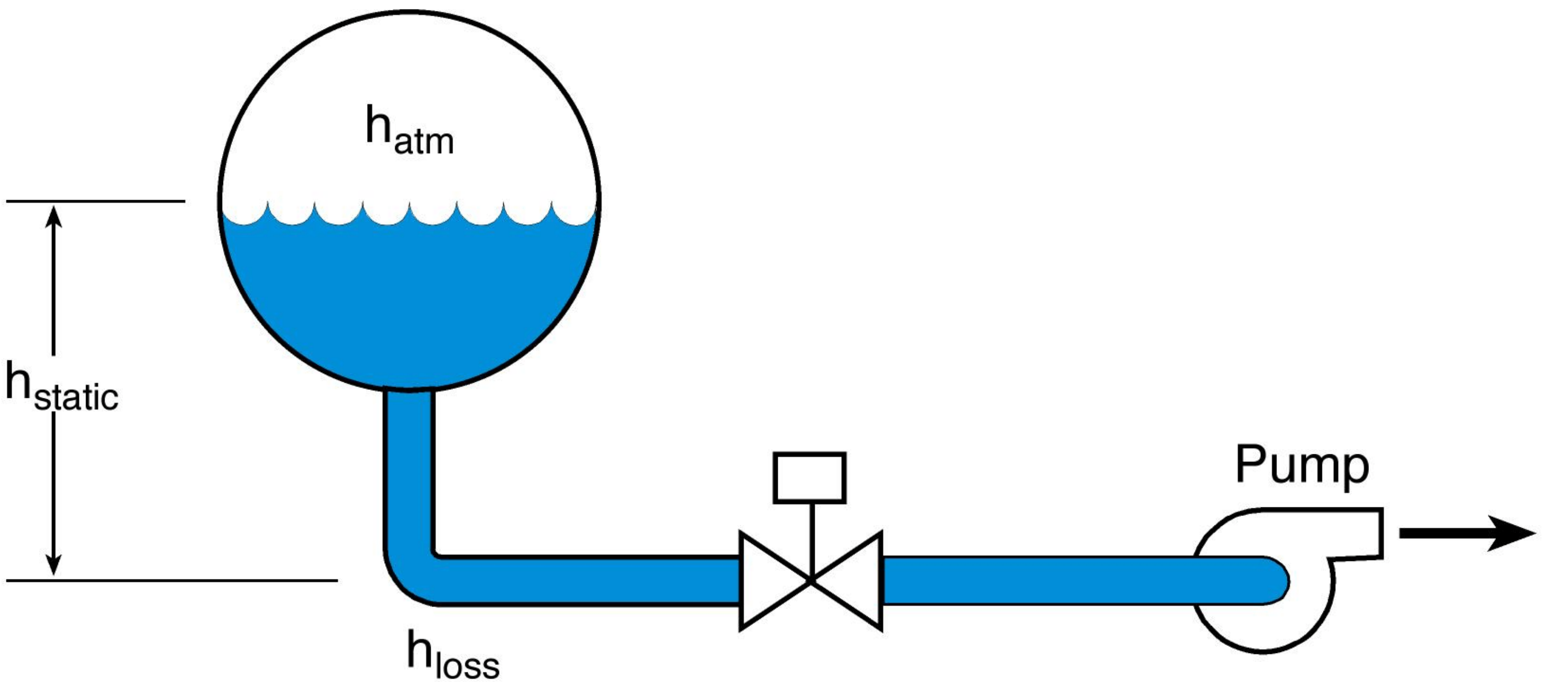
John Rommel

Power Uprate Engineering Director

Exelon Generation®

Elimination of CAP Credit

$$\text{Available NPSH} = h_{atm} + h_{static} - h_{loss} - h_{vp}$$



Exelon Generation.

Elimination of CAP Credit

- Opportunity to improve margins and remove concerns associated with Containment Accident Pressure (CAP) Credit
- Became key project goal
- Credible options existed to eliminate CAP Credit at PB

Exelon Generation.

Elimination of CAP Credit

Current Licensing Basis

- CAP Credit taken for following events
  - LOCA (both long and short term)
  - SSLB
  - Appendix R
  - ATWS
  - SBO

- Maximum CAP Credit Required: 6.1 psig

  LOCA (Long Term)

Exelon Generation.

Elimination of CAP Credit

Actions to Eliminate CAP Credit

- Increase Residual Heat Removal (RHR) system heat removal capability
  - RHR and High Pressure Service Water (HPSW) cross-tie modifications
  - Increase RHR Heat Exchanger (HX) K-Value
- Reduce RHR pump flow
- Credit Condensate Storage Tank (CST) as suction source for special events
- Increase Standby Liquid Control (SLC) system Boron-10 enrichment

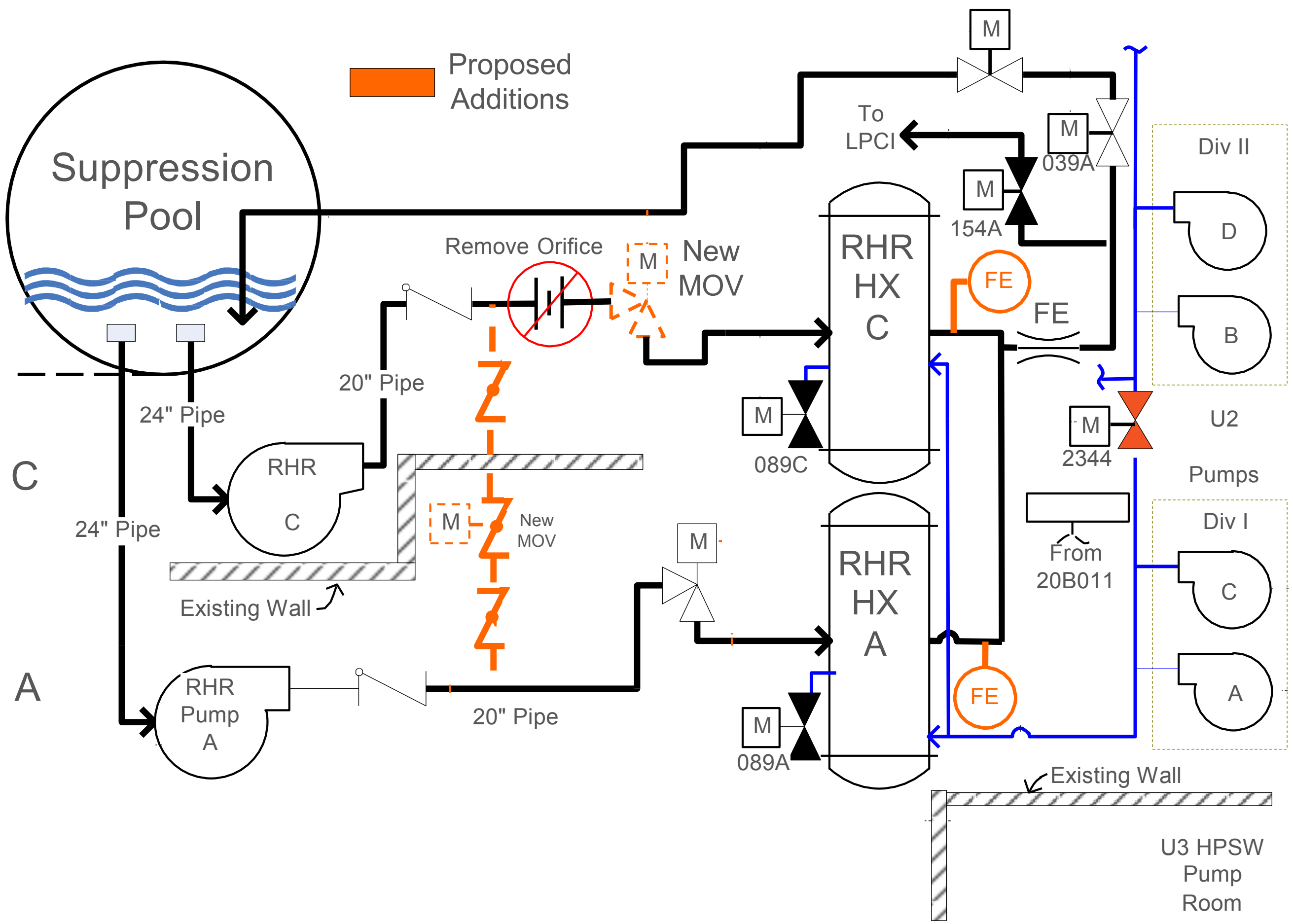
Elimination of CAP Credit

Methodology

Modification or Analytical Change	DBA-LOCA	SSLB	App R	ATWS	SBO
RHR HX Cross-tie and HPSW Cross-tie mods	X	X			
Increased single RHR HX K-Value from 270 to 305	X	X	X	X	X
Reduced RHR flow rate from 10000 gpm to 8600 gpm	X	X	X	X	X
Credit CST as HPCI and/or RCIC suction source			X	X	X
Increase SLC Boron Enrichment				X	

Elimination of CAP Credit

U2-DIV I RHR and HPSW Cross-Tie



Exelon Generation

RHR/HPSW Cross-tie Modifications

- Modifications will:
  - Allow two RHR HXs to be supplied from one RHR pump
  - Improve rate of Suppression Pool cooling
  - Lower peak Suppression Pool temperature, increasing NPSHA
  - Lower required RHR flow, decreasing $NPSHR_{eff}$
- Modifications consist of:
  - New cross-tie line with a normally closed cross-tie isolation on discharge of RHR pumps
  - New flow control valves upstream of each heat exchanger to balance flow
  - Replacement of existing HPSW cross-tie valve with one that can be repositioned against the full flow and differential pressure of a single HPSW pump

CST Modifications

- **Modifications will:**
  - Ensure adequate inventory in CST
  - Ensure that HPCI /RCIC pump suctions remain aligned to the CST
  - Produce additional heat capacity in Suppression Pool
  - Lower peak Suppression Pool temperature, increasing NPSHA
  - Provide additional volume (height) in torus, increasing pump NPSHA

- **Modifications consist of:**
  - A standpipe to control the volume of CST
  - Installation of key lock switches in the Control Room to prevent inadvertent suction source swap
  - Raising torus high level setpoint to prevent premature automatic switch of HPCI suction to Suppression Pool
  - Revised procedural guidance to ensure adequate CST inventory makeup from RWST

Elimination of CAP Credit

Operator Actions

- Limiting LOCA and SSLB (w/EDG failure to start)

  Within 1 hour:
  - Start 1 additional HPSW pump
  - Open MOV to establish HPSW flow through 2nd HX
  - Open new RHR cross-tie MOV
  - Balance RHR flow through 2 HXs

- ATWS /App R
  - Open RWST to CST transfer valves

Exelon Generation.

Elimination of CAP Credit

Conclusions

-For all events

- NPSHA > $NSPHR_{eff}$

-No CAP Credit is required

Exelon Generation.

Nuclear Design and Safety Analyses

Transient and Accident Analyses
Limiting Events

Dave Henry
Sr Manager Design Engineering

Exelon Generation.

Transient and Accident Analyses at EPU

Transient Response

- Limiting events are re-evaluated on a cycle to cycle basis
- Evaluation demonstrated minor changes in Critical Power Ratio (CPR) from CLTP to EPU conditions

Accident Response

- Peak clad temperature during limiting SBLOCA increased 47degrees to 1912°F, below 2200°F limit (DBLOCA peaks at 1728°F)
- Control Rod Drop Accident (CRDA) unaffected by EPU conditions

Containment Response

- Suppression pool temperature is reduced in all design bases events due to the modifications. SBO temperature increases from CLTP but remains below limit
- Suppression Pool and drywell pressure increase slightly, below limit
- Drywell air and shell temperature meets limit

Flow Induced Vibration and Structural Analyses

EPU Flow-Induced Vibration

Reactor Vessel Structural Topics

Dave Henry
Sr Manager Design Engineering

EPU FIV Effects and Modifications

Effect on the power plant

- Main Steam (MS) Line and Feedwater (FW) flow increase ~12.4%
- Vibration levels in MS and FW are expected to increase 30 to 35%
- Extraction Steam (ES) Flow increases up to 33% in some lines
- Heater Drain (HD) flow from the 5th stage to the 4th stage heater increases ~35%
- Maximum Core flow and reactor pressure remain unchanged

Evaluation and Screening Process Performed

Results

- Upgraded thermowells
- Small bore piping modifications
- New and modified Main Steam Line supports
- All Code and regulatory requirements met

FIV Monitoring Program

Piping vibration startup test program will be performed during EPU power ascension

- Detailed analyses performed to establish monitoring locations and acceptance criteria
- Multiple components will be monitored inside and outside of the drywell
- Power increases made in predetermined increments so that EPU vibration levels can be projected before CLTP RTP is exceeded

EPU – RPV and Internals

Flow Induced Vibration Effects

- Analyses performed to evaluate FIV effects on reactor internals
- Maximum core flow is not increased by EPU therefore core flow dependent RPV internals not affected by EPU
- Analysis extrapolated to 102% of EPU power level
- Vibration levels were below acceptance criterion for austenitic stainless steel
- Structural Integrity of Reactor Internal components confirmed

Structural Effects

- Design conditions not changed by EPU
- Site specific analyses, measurement and inspection programs verify the structural integrity of the Replacement Steam Dryer
- All stresses and Cumulative Usage Factors (CUFs) within design basis Code allowables
- RPV pressure retaining and internal components maintain structural integrity at EPU conditions

EPU – RPV and Internals – Continued

Fracture Toughness and Materials

- RPV meets 10 CFR 50 Appendix G requirements
- Fluence values calculated for EPU using NRC-approved GEH neutron fluence methodology
- Inspection requirements based on BWRVIP program
- Current inspection strategy for RCPB is acceptable

Power Ascension Plan

Power Ascension Test Preparation

Major Testing

PAT Non-Dryer Acceptance Criteria

Jim Kovalchick

PBAPS Sr Manager Operations, EPU Integration

Power Ascension Test Preparation

- EPU test plan developed using guidance of SRP 14.2.1 (Generic Guidelines for EPU Testing Programs)
- Equipment modification acceptance testing will be verified satisfactory prior to start up
- Performance testing for modifications will be integrated into a single controlling Power Ascension Test Procedure to verify aggregate effect of EPU and modifications does not impact safety
- Test plan consists of 18 individual tests
  - 16 tests from original startup testing scope
  - Wide Range Neutron Monitor (WRNM)Calibration
  - Steam dryer power ascension test plan
- Tests developed and will be performed by personnel experienced in PBAPS testing

Power Ascension Major Testing

Test Description	Test Condition (%CLTP)					
	≤90	95	100	104.2	108.3	EPU
Chemical/ Radiochemical		x	x	x	x	x
Radiation Measurement		x	x	x	x	x
Control Rod Drives			x	x	x	x
Steam Dryer	x	x	x	x	x	x
WRNM	x					
APRM/PRNM Calibration	x	x	x	x	x	x
RCIC	x					x
HPCI	x					x

Power Ascension Major Testing (CONT'D)

Test Description	Test Condition (%CLTP)					
	≤90	95	100	104.2	108.3	EPU
Core Power Distribution	x					x
Core Performance	x	x	x	x	x	x
Pressure Regulator	x	x	x	x	x	x
Feedwater System	x	x	x	x	x	x
Bypass Valves	x					
MSIVs	x					
Turbine Valve testing	x					
Reactor Recirculation System	x	x	x	x	x	x
Vibration	x	x	x	x	x	x
Plant Monitoring	x	x	x	x	x	x

PAT Non-Dryer Acceptance Criteria

- Level 1 Acceptance Criteria – Associated with design performance

- If a Level 1 Test Criterion is not met:
  - The plant will be placed in a hold condition judged to be satisfactory and safe based on prior testing
  - Resolution will be pursued by equipment adjustments or engineering evaluation
  - Plant Operations Review Committee (PORC) must approve corrective actions
  - Applicable test portion must be repeated and results presented to PORC prior to increasing reactor power

PAT Non-Dryer Acceptance Criteria

- Level 2 Acceptance Criteria – Associated with performance expectations

- If a Level 2 Test Criterion is not met:

  - An evaluation will be initiated to identify cause and corrective actions
  - PORC must approve corrective actions
  - If physical adjustments are required, test portion will be repeated to verify Level 2 requirement is satisfied prior to increasing power

CLOSED SESSION

Replacement Steam Dryer - Exelon

Acronym List

- AOV – Air Operated Valve
- APRM – Average Power Range Monitor
- ASME – American Society of Mechanical Engineers
- ATWS – Anticipated Transient Without Scram
- BOP – Balance of Plant
- BWR – Boiling Water Reactor
- BWRVIP – Boiling Water Reactor Vessel Internals Program
- CAP – Containment Accident Pressure
- CD – Condensate System
- CLTP – Current Licensed Thermal Power
- CLTR – Constant Pressure Power Uprate
- CPR – Critical Power Ratio
- CRDA – Control Rod Drop Accident
- CST – Condensate Storage Tank
- CUF – Cumulative Usage Factor
- DBLOCA – Design Basis Loss of Cooling Accident
- EDG – Emergency Diesel Generator
- ELTR – Extended Power Uprate Licensing Topical Report
- EPU – Extended Power Uprate
- ES – Extraction Steam
- FFWTR – Final Feedwater Temperature Reduction
- FIV – Flow Induced Vibration
- FW – Feedwater
- GEH – GE-Hitachi
- HD – Heater Drain
- HP – High Pressure
- HPCI – High Pressure Coolant Injection
- HPSW – High Pressure Service Water
- HX – Heat Exchanger
- IASCC – Irradiation Assisted Stress Corrosion Cracking
- IGSCC – Intergranular Stress Corrosion Cracking
- IMLTR – Interim Methods Licensing Topical Report
- MASR – Minimum Alternating Stress Ratio
- Mlbm – Million pound mass
- MNGP – Monticello Nuclear Generating Plant
- MOV – Motor Operated Valve
- MPS – Minimum Recirculation Pump Speed
- MS – Main Steam
- MSIV – Main Steam Isolation Valve
- MSL – Main Steam Line
- MWT – Megawatt Thermal
- NPSH – Net Positive Suction Head
- NPSHA – Net Positive Suction Head Available
- NPSHR – Net Positive Suction Head Required
- $NPSHR_{eff}$ – Effective Net Positive Suction Head Required
- NSSS – Nuclear Steam Supply System
- OLTP – Original Licensed Thermal Power
- PBAPS – Peach Bottom Atomic Power Station
- PORC – Plant Operations Review Committee
- PRFO – Pressure Regulator Failure Open

Acronym List (CONT'D)

- PRNM – Power Range Neutron Monitor
- psia – pounds per square inch absolute
- psig – pounds per square inch gauge
- QC – Quality Control
- RCIC – Reactor Core Isolation Cooling
- RCPB – Reactor Coolant Pressure Boundary
- RHR – Residual Heat Removal
- RIPD – Reactor Internal Pressure Difference
- RPV – Reactor Pressure Vessel
- RSD – Replacement Steam Dryer
- RTP – Rated Temperature and Pressure
- RWST – Refueling Water Storage Tank
- SBO – Station Blackout
- SRV – Safety Relief Valve
- SLC – Standby Liquid Control
- SSLB – Small Steam Line Break
- TS – Technical Specification
- VPF – Vane Passing Frequency
- WRNM – Wide Range Neutron Monitor

June 10, 2014

Before the Advisory Committee on Reactor Safeguards
Re: Nuclear Regulatory Commission's Draft Safety Evaluation in Support of the Proposed Extended Power Uprate License Amendment for the Peach Bottom Atomic Power Station Units 2 & 3

Testimony of Eric Epstein, Chairman of Three Mile Island Alert , Inc. to Postpone Approval of the Proposed Extended Power Uproot License Amendment for the Peach Bottom Atomic Power Station Units 2 & 3 Until Open and Unresolved Environmental, Health & Safety Issues Are Addressed

I. Introduction.

The Peach Bottom Atomic Power Station (“Peach Bottom”) located in southern York County, Pennsylvania is co-owned by (“Exelon”) based in Illinois and Public Service and Gas (“PS&G”) of New Jersey.

Philadelphia Electric's (“PECO”) applied for a license to operate the Peach Bottom Atomic Power Station in July, 1960. The application was approved by the Atomic Energy Commission (“AEC”).

Peach Bottom-1 was a 40 megawatt (“MWt”), High Temperature Graphite Moderated reactor that operated from 1966-1974.

Peach Bottom 2 & 3 are Boiling Water Reactor designed by General Electric and engineered by Bechtel. Both plants use a Mark 1 containment system. Peach Bottom 2’s initial capacity was 1,159 MWt. Peach Bottom 2’s capacity was initially set at 1,035 Net MWt for a total capacity of 2,194 MWt.

The construction permit for PBAPS, Units 2 and 3, was issued by the AEC on January 31, 1968. Both units were evaluated against the then-current AEC draft of the 27 General Design Criteria (“GDC”) issued in November 1965.

On July 11, 1967, the AEC published for public comment, in the *Federal Register* (32 FR 10213), a revised and expanded set of 70 draft GDC. The licensee concluded that PBAPS, Units 2 and 3, conforms to the intent of the draft GDC.”

On February 20, 1971, the AEC published in the *Federal Register* a final rule that added Appendix A to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, "General Design Criteria for Nuclear Power Plants".

The NRC decided not to apply the final GDC to plants with construction permits issued prior to May 21, 1971.

Unit 2 and Unit 3 began operation in July, 1974, but had their licensees extended by the Nuclear Regulatory Commission ("NRC") and are expected to operate though 2034.

On March 31, 1987, PECO was ordered by the Nuclear Regulatory Commission to shutdown Peach Bottom 2 and 3 on due to operator misconduct, corporate malfeasance and blatant disregard for the health and safety of area.

On February 3, 1988 , John H. Austin resigned as president of PECO after a unusually critical report by the Institute of Nuclear Power Operations (INPO) was published. The report asserted that Peach Bottom "was an embarrassment to the industry and to the nation." Zack T. Pate, president of INPO, added, "The grossly unprofessional behavior by a wide range of shift personnel ... reflects a major breakdown in the management of a nuclear facility."

On February 1, 1989, the NRC staff recommended that nuclear power plants that utilize the Mark 1 containment shell, modify the structure to reduce the risk of failure during a serious accident. PECO said it would make the $2 to $5 million changes only if the NRC.

Commission makes the modifications a requirement. This was the second time in two years that the NRC staff has advised the Commission to make changes to the Mark 1 containment structure.

The NRC released a report on June 21, 1989 relating to Mark 1 containment buildings entitled "Severe Accident Risks: An Assessment for Five U.S. Nuclear Plants." The NRC's six-member panel were evenly divided as to whether the Mark 1 containment would be breached during a serious accident. "The NRC decided not to order immediate changes in the Mark 1 containment." Yet half of the panel stated "with near certainty" the Peach Bottom's containment structure would fail during a core melt accident.

On April 21, 2000, the NRC approved the transfer of the Peach Bottom licenses from Delmarva Power and Light Company and Atlantic City Electric Company to PECO and PSEG Nuclear LLC.

By 2002, the NRC had approved Measurement Uncertainty Recapture Uprates and Stretch Uprates for Peach Bottom 2 & 3. The proposed amendments would authorize an increase in the maximum reactor power level from 3,514 megawatts thermal (MWt) to 3,951 MWt.

On August 2, 2005 Exelon Generation Company, LLC, on behalf of itself and PSEG Nuclear LLC, filed to acquire 100% of the facility following approval of the proposed license transfers.

In December, 2006 Exelon was fined $640,000 by the Susquehanna River Basin Commission ("SRBC") for water violations at Peach Bottom related to water use and power uprates. (SRBC, Docket #: 20061209). Exelon failed to seek the Commission's approval for any change in their processes that required them to increase water usage by 100,000 gallons a day.

Peach Bottom nuclear units were licensed to operate for 40 years and designed to produce 2,194 net MWt. Forty years later, the plants' operational lives have been extended by an additional twenty years and their combined capacity will increase to 3,951 MWt.

II. History of Power Uprates at Peach Bottom Atomic Power Station Units 2 & 3

Peach Bottom 2 received approval for a5% stretch uprate or 165 MWt increase on October 18, 1994. Peach Bottom 3 received approval for a 5% stretch uprate or 165 MWt increase on July 18, 1995.

Peach Bottom 2 & 3 received approval for a 1.62% Measurement Uncertainty Recapture ("MUR") uprate or 56 MWt increase on November 22, 2002.

Peach Bottom 2 received approval for a 5% stretch uprate or 165 MWt increase in October 18, 2004.

In December, 2006 Exelon was fined $640,000 by the Susquehanna River Basin Commission ("SRBC") for water violations at Peach Bottom related to water use and power uprates.

On September 28, 2012, Exelon Generation Company, LLC ("Exelon" or "the licensee") submitted a license amendment request for Peach Bottom Atomic Power Station, Units 2 and 3.

Peach Bottom announced an Extended Power Uprate (EPU) to 3,951 MWt core power for both units, which is 120% of Original Licensed (core) Thermal Power. The project was authorized for full implementation by co-owners Exelon and PSEG in July 2012. Implementation of modifications required for the EPU are planned over three refueling outages and during "online periods."

On April 5, 2002, Exelon outlined the projected timeline for approval of License Amendment Request and anticipated approval in May 2014.

In summary, the Extended Power Uprate process has been fluid with many open ended issues only recently closed out or left to future commitments as posted in the Federal Register.

III: Peach Bottom's Environmental Impacts on the Susquehanna River Basin

Peach Bottom does not use a closed-cooling system. The Peach Bottom Atomic Power Station uses and treats potable water from the Susquehanna River. The average daily usage is anywhere from 280,000 to 360,000 gallons per day.

The station does not currently use evaporative cooling towers for cooling needs, but evaporates up to 28 million gallons daily ("mgd") through heat transfer via once-through cooling with water withdrawn from Conowingo Pond. The Peach Bottom Atomic Power Station, located on the west bank of the Conowingo Pond in York County, Pennsylvania and 36 miles from downtown Baltimore- is a two-unit nuclear generating facility that uses water from the Conowingo pond for cooling purposes.

Water shortages on the Lower Susquehanna reached critical levels in the summer of 2002. For the month of August 2002, 66 of 67 Pennsylvania counties had below normal precipitation On August 9th, 2002, Governor Schweiker extended the drought emergency for 14 counties across Southcentral and Southeast Pennsylvania. Precipitation deficits at or exceeding 10.0 inches were recorded in several counties, included Dauphin County. The greatest deficit of 14.6 inches was in Lancaster County, and departures from normal precipitation range included 0.0 inches in York County. Peach Bottom is located in Lancaster and York Counties while Three Mile Island is situated in Dauphin and Lancaster Counties. (Pennsylvania Department of Environmental Protection, *Drought Report* and *Drought Conditions Summary*, August-September, 2002).

Ten years later in April 2012, the Susquehanna River reached record seasonal lows matching drought conditions of 1910 and 1946. U.S. Geological Survey analysis showed stream flows at hydrological emergency levels in 42 of the state’s 67 counties as of Monday. Another 10 counties were at warning levels, and another 12 at watch level. Only three were normal or above. Groundwater levels are at emergency levels in 13 counties. The SRBC began issuing temporary orders to cease water withdrawals in February, 2012.

The Lower Susquehanna River is impacted abnormal weather conditions. For example, “periods of drought or extended periods of low flow can adversely affect the ability of the dam to meet minimum flow and summertime pond level minimums. In addition, due to high ambient and water temperatures and low flow, maintaining the minimum dissolved oxygen requirement is also challenging. These situations can further be compounded if the flows coming into the pond as measured at the Marietta gage do not equal the flow outfalls. This not only affects the dam, but also the water supply companies and Peach Bottom Atomic Power Station due to the loss of pond level. Additionally, recreational boating and marina operation becomes severely hampered due to low water levels. (“Conowingo Pond Management Plan,” *Publication No. 242* , June 2006, p. 71.)

The Susquehanna Ricer Basin is flood prone. “Since record-keeping began 200 years ago, the Susquehanna River has proven one of the most flood-prone watersheds in the nation. The watershed encompasses 27,510 square miles and extends from New York to Pennsylvania to the

Chesapeake Bay in Maryland – where nearly 4 million people live...Of the 1,400 communities in the river basin, 1,160 have residents who live in flood-prone areas.” (7th Annual Susquehanna River Symposium, Bucknell University, October 12-13, 2012)

Extreme weather events occur with more frequency including Tropical Storm Lee in 2011. Additionally, droughts have become more common in the Susquehanna River Basin.

Unlike other consumptive user i n the summer of 2002, Peach Bottom, did not “conserve” water until the plant was forced to close to address a massive fish kill. On August 30, 2002, high differential pressures on the circulating water intake screens forced the manual shut down of Peach Bottom. “The problem was caused by a sudden surge in the amount of fish (Gizzard Shad) that entered the intake canal and clogged the screens. Unit 3 power was returned to 100 percent following cleaning of the circulating water screens and restating of the 3’A’ circulating water pump.” (Nuclear Regulatory Commission, IR-50-277/02-05; 50-278/02- 05).

Five years later in the summer of 2007, Peach Bottom-2 & 3 was detected returning water to the Susquehanna River at temperatures in excess of 110 degrees.

Communities and ecosystems that depend on limited water resources are adversely affected by “normal operating conditions” at nuclear stations.

The Conowingo Pond also plays a cortical role in Peach Bottom's water intake. Declining pond levels threaten Peach Bottom's cooling water intake, recreational use of the Conowingo pond, shore habitat levels, and downstream flows. As drought conditions continue, the operators continue to generate hydroelectricity as much as possible using the water available to them, but it becomes a secondary concern. The primary concern becomes the depletion of storage in the pond and safeguarding the ability of the pond to continue to make adequate releases during low flow events of extended duration." ("Conowingo Pond Management Plan," *Publication No. 242* June 2006 p. 21.)

"The Conowingo pond provides a mixed warm water recreational fishery for largemouth and small mouth bass, channel catfish, white crappie, bluegill, and to lesser degrees, striped bass, walleye and carp. The most abundant fish in the Conowingo pond is the gizzard shad. Bass fishing tournaments are commonplace during the open season. Steep, wooded slopes and railroad postings limit shoreline and boat access. The heated effluent from Peach Bottom Atomic Power Station attracts game fish during the winter and extends the open-water fishing season. ("Conowingo Pond Management Plan," *Publication No. 242*, June 2006, p. 13).

"Millions of fish (game and consumable), fish eggs, shellfish and other organisms are sucked out of the Lower Susquehanna River and killed by nuclear power plants annually. It is hard to know just what the impact on fisheries is, because cool water intakes have been under the radar screen compared to some types of pollution, said Pennsylvania Fish and Boat Commission aquatics resources chief Leroy Young." (Ad Crable, *Intelligencer Journal*, January 15, 2005).

A former Peach Bottom nuclear plant employee said he was "sickened" by the large numbers of sport fish he saw sucked out of the Susquehanna. "When the water comes in, fish would swim in through tunnels and swim into wire baskets," said the man who lives in southern Lancaster County and asked that his name not be used. "There were hundreds and hundreds of fish killed each day. Stripers and bass and walleye and gizzard shad and all kinds of fish. It took a forklift to carry them out" (*Intelligencer Journal*, January 15, 2005).

Water use and water consumption - as well as water supply and water chemistry - have direct and indirect relationships with safety related components, plant cooling, and are intimately connected to the health and safety of the Susquehanna River and the regional community.

IV. Legal Arguments for Revising the Nuclear Regulatory Commission's Draft Safety Evaluation.

The fragmentation of "regulatory oversight" or the segmentation of a large or cumulative project into smaller components in order to avoid designating the project a major federal action has been held to be unlawful. *City of Rochester v. United States Postal Serv., 541 F.2d 967, 972 (2d Cir. 1976)* .

"To permit non comprehensive consideration of a project divisible into smaller parts, each of which taken alone does not have a significant impact but which taken as a whole has cumulative significant impact, would provide a clear loophole to NEPA."); *Scientists' Inst. for Pub. Information, Inc. v. AEC, 156 U.S. App. D.C. 395, 481 F.2d 1079, 1086n.29, 1086-89 (D.C.Cir. 1973)* (statement required for overall project where individual actions are related logically or geographically). See generally W. Rodgers, Environmental Law ßß 7.7, 7.9 (1977) (discussing problems arising from scope and timing of environmental impact statements).

Federal and statewide statues can not be unilateral exempted or ignored by coordinated inaction.

Regional water coordination was clearly recognized by the Department of Environmental Protection ("DEP") on June 16, 2007 when the DEP advertised that the Susquehanna River Basin Commission was proposing comprehensive revisions to its regulations governing water withdrawal and consumptive use projects. (Proposed Rules [Federal Register: October 1, 2007 (Volume 72, Number 189) [Page 55711-55712] PART 808.)

The regional changes include a number of markers that the DEP and the NRC must address when consider Exelon's EPU request including a reduce the duration of consumptive use and withdrawal approvals from 25 years to 15; ending the recognition of "pre-compact" or "grandfathered" consumptive uses or withdrawals upon a change of ownership, and no longer allow the transfer of project approvals when a change of ownership occurs; and a require that sponsors of consumptive use projects involving ground or surface water withdrawals request approvals for the consumptive use and the withdrawals.

The SRBC stated, "If additional releases are made from new or existing sources, they will need to be accounted in the monitoring data at the Marietta gage. It will be important to understand how operations of Conowingo Dam will be affected and how existing CU [Consumptive Use] mitigation agreements for Peach Bottom Atomic Power Station and the City of Baltimore could be impacted. Operations of Conowingo Dam are driven by flows at Marietta, as are existing mitigation agreements for the Peach Bottom Atomic Power Station and the City of Baltimore. It will be necessary to specify that those agreements remain in force despite upstream mitigation, and to resolve methodologies for implementing the agreements in instances when upstream mitigation releases are distorting the flow measurements at Marietta. Regardless, Exelon and Baltimore will still be required to mitigate the CU of their projects." (Consumptive Use Mitigation Plan, *Publication No. 253*, March 2008, p. 29)

The Department of Environmental Protection and the Nuclear Regulatory Commission **exempted** Peach Bottom Atomic Power Station from preparing a final Environmental Impact Statement.

The Final Environmental Impact Statement ("EIS") was concluded by the NRC's predecessor agency - the Atomic Energy Commission - **in 1973** - prior to the Commonwealth of Pennsylvania enactment of aggressive statutes and regulations. Among the legislation passed were the Radiation Act (1984), Chesapeake Bay Commission Agreement Act (1985), Hazardous Site Cleanup Act (1988), Pennsylvania Environmental Stewardship and Water Protection Act (1999) and Act 129 (2008).

The initial EIS was issued decades prior to the emergence of the Environmental Protection Agency ("EPA") Section 316(b) of the Clean Water Act. EPA issued regulations on the design and operation of intake structures in order to minimize adverse environmental impacts.

EPA promulgated regulations in 2001, 2003, 2006 and 2014. The requirements are included in the National Pollutant Discharge Elimination System ("NPDES") permit regulations, 40 CFR Parts 122 and 125 (Subparts I, J, and N).

The NRC must investigate the impact of the Environmental Protection Agency (EPA) 316 (a) and 316 (b) and establish compliance milestones on applications from nuclear power plants.

Additionally, the traditional implications of the Pennsylvania Public Utility Commission ("Pa PUC") policy and regulations relating to "withdraw and treatment" of water, i.e., referred to as "cost of water" under the Public Utility Code, Title 66, have to be factored in this application absent a PUC proceeding as well as Act 220 water usage guidelines.

Power generation, cooling and safety are inherently connected. There is no imaginary fence between generation and safety. And there should be no regulatory moat created by artificial safety definitions erected by nuclear regulators.

Neither DEP or NRC can bypass Act 220 of 2002 which "establishes the duty of any person to proceed diligently in complying with orders of the DEP." (Section 3133)

Seasonal flow, Act 220, and the competing demands for limited water resources may make the amount of water available for power generation unreliable. Frequent power decreases and scrams show up as safety indicators and put stress on the nuclear generating stations. The NRC does not compile generation indicators, it analyzes safety indicators, like scrams and power reductions. The uprate clearly has the potential to create safety challenges by abruptly scramming the plant or forcing power reductions to accommodate a water use budget.

V. The NRC Staff's Draft Safety Evaluation is Replete with Assumptions, Generalizations and Delayed Compliance Deadlines.

The Federal Register Notice ("FR" or "the Notice") is populated with general, unqualified and vague assumptions and statements posited as empirical data.

The plant's cooling towers are not ''routinely used'' (see ''Aquatic Resource Impacts''); and, are not planned to be ''routinely used'' during and after implementation of the EPU. Therefore, consistent with the discussion in NUREG–1437, Supplement 10, Section 2.2.8.4, ''Visual Aesthetics and Noise,'' there should not be any significant impacts from the EPU, such as icing, fogging, plume, or noise impacts from the operation of cooling towers."

Please define and quantify the terms "plume" and "routinely." (FR, p. 18075)

The Federal Register projected, "Once the EPU has been implemented, water consumption for plant cooling will not significantly change from pre-EPU operation." (FR, p. 18075)

Please define and quantify current and post water consumption levels and define the term "significantly."

"If the proposed EPU is approved and is implemented, PBAPS is predicted to have a slightly larger and hotter mixing zone than pre-uprate conditions during full flow and capacity." (FR, p. 18079)

Please define and quantify “slightly larger” and “hotter mixing zone.”

“The NRC staff anticipates that PBAPS will continue to operate post-EPU in full compliance with the requirements of the PADEP. The PADEP would evaluate PBAPS compliance with its individual wastewater facility permit. “(FR, p. 18079)

How does the NRC measure and verify “anticipation?”

“The potential impacts to aquatic resources from the proposed action could include impingement of aquatic life on barrier nets, trash racks, and traveling screens; entrainment of aquatic life through the cooling water intake structures and into the cooling water systems; and effects from the discharge of chemicals and heated water.” (FR, p. 18075)

The NRC staff concluded in NUREG–1437, Supplement 10, Section 4.1.3, ‘‘Impingement of Fish and Shellfish;’’ that, during the continued operation of PBAPS, the potential impacts caused by the impingement of fish and shellfish on the debris screens of the cooling water intake system would be small (i.e., not detectable or so minor that they will neither destabilize nor noticeably alter any important attribute of the resource) and that impingement losses would not be great enough to adversely affect Susquehanna River aquatic populations.”

The NRC staff also concluded in NUREG–1437, Supplement 10, Section 4.1.3, “that, in the early life stages in the cooling water system, the potential impacts of entrainment of fish and shellfish would be small, and that there are no demonstrated, significant effects to the aquatic environment related to entrainment.”

The NRC provided no empirical data to support environmental impact conclusions,and ignored the aggregate impact of three EPUs implemented since the initial license was granted.

The staff also failed to define and quantify “alter,” “so small, or “significant impact.”

Staff’s conclusions relating to “Aquatic Resource Impacts” are based on ongoing studies and appears to co-mingled and mix assumes station conditions under the grandfathered NPDES permit:

> However,this conclusion was made assuming station conditions under the previous NPDES permit... After the study is completed and based on the study results, Exelon will submit to PADEP an application to modify the NPDES permit. These modifications may include actions to manage the thermal discharge under EPU conditions. For any such future modifications, the PADEP must, in accordance with Section 316(a) of the Clean Water Act, ensure thermal effluent limitations assure the protection and propagation of a balanced indigenous community of shellfish, fish, and wildlife in and on Conowingo Pond.” (FR, 18706)

The conclusions stated under “Aquatic Resource Impacts” may not be consistent with EPA 316 (b), and are based on a dated NPDES permit, and the NRC is allowing delayed implementation of to Peach Bottom based on pending statutes. (FR, p. 18075).

Why are DEP and the NRC granting waivers based on outdated assumptions, data and studies to be concluded at a later date?

The NRC conclusions are also inconsistent with the historical facts on the ground as enumerated in the discussed under III. Peach Bottom's Environmental Impacts on the Susquehanna River Basin, pp. 6-10.

Regarding the potential impacts of thermal discharges, in NUREG–1437, Supplement 10, Section 4.1.4, "Heat Shock," the NRC staff concluded that the "impacts are small and that the heated water discharged to Conowingo Pond does not change the temperature enough to adversely impact balanced, indigenous populations of fish and wildlife." (FR, pp. 18075-10876).

What are the small impacts and why did the EPA, the NRC and the SRBC accept a generic rather than a site specific evaluation? Has the EPA, the NRC or SRBC anticipated or projected impacts after the "renewed license period…"? If the period is more than 15 years, please explain how this time period has been exempted by SRBC regulations.

Additionally, the NRC failed to explain how the intake structure is designed to reduce the impingement and entrapment of aquatic organisms, and how this design comports with 316 (b).

Moreover, the NRC has "generically" determined that the "effects from discharge of chlorine or other biocides, as well as accumulation of contaminants in sediments or biota, would be small for continued operations during a renewed license period at all plants as discussed in Section 4.5.1.1, "Surface Water Resources, Discharge of Biocides, Sanitary Wastes, and Minor Chemical Spills," of the "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," NUREG–1437, Volume 1, Revision 1, dated June 2013." (ADAMS Accession No. ML 13106A241). (FR, p. 18076)

What and where are the plan(s) to confirm and monitor what and how much "chemical effluents [are] discharged"? How are regulatory agencies going to monitor the changes or quantify or type of discharges?

The DEP and the NRC failed quantify site-specific aquatic challenges, and invasive species challenges based on the documented challenges that currently exist in the Susquehanna River.

The DEP confirmed that zebra mussel adults and juveniles have been found in Goodyear Lake, the first major impoundment on the Susquehanna River's main stem below Canadarago Lake in New York. Zebra mussels are an invasive species posing a serious ecological and economic threat to the water resources and water users downstream in the river and Chesapeake Bay. On June 19, 2007, zebra mussels were discovered in Cowanesque Lake, Tioga County. This marks the first time zebra mussels have been discovered in the area.

> "In 2002, the first report of zebra mussel populations in the Chesapeake Bay Watershed were reported from Eaton Reservoir in the headwaters of the Chenango River, a major tributary to the Susquehanna River in New York. A short time later, zebra mussels also were found in Canadarago Lake, a lake further east in the Susquehanna main stem headwaters. Now, through DEP's Zebra Mussel Monitoring Network, reports were received that both zebra mussel adults and juveniles, called veligers, have made their way down to the Susquehanna main stem headwaters."
>
> (Pa DEP, *Update*, July 16, 2004)

Zebra mussels, like Asiatic clams, shad and other biological fouling, can invade the Peach Bottom Atomic Power Station from the Chesapeake Bay or Susquehanna River.

Zebra mussels have been discovered at the Susquehanna Steam Electric Station's fail-safe water supply in Cowanesque Lake and noted: "There is no evidence zebra mussels have been found in anywhere in the vicinity of the SSES..." But the NRC acknowledges the "SRBC requirement that the SSES compensate consumptive water use during river low-flow conditions by sharing the costs of the Cowanesque Lake Reservoir, which provides river flow augmentation source.

In recent years, Algae blooms recently "caused continuous clogging of multiple strainers of all pumps in TMI the intake structure; including: the two safety related DR pumps, all three safety related NR pumps, and all three non-safety related secondary river pumps." (NRC IR 05000289/2006004, p. 7.)

Neither DEP, NRC or SRBC addressed health, safety and structural challenges caused by micro fouling versus macro fouling, micro biologically influenced corrosion, algae blooms, biofilm's disease causing bacteria such as Legionella and listeria, the difficulty in eliminating established biofilms, oxidizing versus non- oxidizing biocides, chlorine versus bleach, alkaline versus non-alkaline environments, possible decomposition into carcinogens, and the eastward migration of Asiatic clams, zebra mussels and the anticipated arrival quagga mussels.

NRC staff noted the limitation of the inspection protocol and "requested that licensees establish a routine inspection and maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling/tube plugging cannot degrade the performance of the safety-related systems supplied by service water. These issues relate to the evaluation of safety-related heat exchangers using service water and whether they have the potential for fouling, thereby causing degradation in performance, and the mandate that there exist a permanent plant test and inspection program to accomplish and maintain this evaluation."

"The regulations in 10 CFR 50.36, set forth NRC requirements related to the content of TSs. Pursuant to 10 CFR 50.36, TSs are required to include items in the following five specific categories: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCOs); (3) surveillance requirements (SRs); (4) design features; and (5) administrative controls. **The regulation does not specify the particular requirements to be included in a plant's TSs.** (NRC, "Peach Bottom Atomic Power Station, Unit 2 & 3, Issuance of Amendment Re: Revise Normal Heat Sink Operability Requirement", Tag Nos. M9805 & M98906, June 5, 2014).

The NRC identified the need for biological and thermal studies. When are the biological and thermal studies going to be completed? Why would the DEP the NRC approve an uprate prior to the completion of the studies? Why is NPDES compliance being delayed until after the uprate is implemented?

VI: Miscellaneous:

The census data - which is 4.5 years old - fails to factor household incomes as it relates to proximate buying power, the Consumer Price Index, commuter times and property taxes. The census data completely ignores fishing and hunting seasons, migrant worker populations and special population including the Amish, Old Order Mennonites and recreational visitors in southern Lancaster and York Counties.

It appears the NRC completely bypassed by the York County Planning Commission. The Commission considers all social, economic, historical, and environmental aspects of projects impact the region.

The U.S. Fish and Wildlife Service has many interests in the relicensing of Conowingo, Muddy Run and Peach Bottom, including the "general health of living resources in the pond and in Conowingo's tail waters; impacts of Conowingo hydropower generation schedule on downstream resources, anadromous fish restoration and safe upstream and downstream passage of fish (especially diadromous species including eels); and the impact of water development projects on aquatic resources (e.g., egg and larvae impingement at water intakes, stream side development, endangered species issues)."("Conowingo Pond Management Plan," *Publication No. 242, p. 76,* June 2006.)

Did the U.S. Fish and Wildlife Service review Exelon's proposed Extended Power Uprate?

The draft SER also assumes the States of Delaware and Maryland do not exist.

There was no discussion of significant historic assets within 50 miles of Peach Bottom including but not limited to: Camp David, the Eisenhower Farm, the First American Capital in York, Gettysburg National Park, Harley-Davidson, Hershey Chocolate, the Pennsylvania Historical and Museum Commission sites and Underground Railroads sites.

No physical changes for radioactive waste disposal were noted which is a strange omission since the NRC approved Peach Bottom as the storage site for Limerick's low-level radioactive waste. Exelon applied to amend Peach Bottom's license in early 2010 to accept low level radioactive waste from Limerick. Exelon can keep the Limerick waste at Peach Bottom for as long as it wants according to NRC spokesman Neil Sheehan sated. "As time goes on, however, the plant may face capacity issues and will need to look for disposal options." (*York Daily Record*, June 1, 2011)

Peach Bottom hosts almost 2,000 tons high level radioactive waste in spent fuel pools and dry casks. The EPU will increase the volume and activity of radioactive solid waste by approximately 14%.

In March 2012, the NRC ordered Peach Bottom Unit 3 to install instrumentation to monitor conditions inside the spent fuel pools also ordered plants owners to develop mitigation strategies to provide assurance of adequate cooling of reactor cores and spent fuel pools when permanent electrical supplies are unavailable for indefinite periods.

VII. Finding of No Significant Impact.

On page 18073, the Summary - which is actually conclusion:

> The U.S. Nuclear Regulatory Commission (NRC) is considering issuance of amendments to Renewed Facility Operating License Nos. DPR–44 and DPR–56, issued to Exelon Generation Company, LLC (Exelon, the licensee), for operation of the Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3, located in York and Lancaster Counties, Pennsylvania. The proposed amendments would authorize an increase in the maximum reactor power level from 3514 megawatts thermal (MWt) to 3951 MWt. The NRC staff is issuing a final Environmental Assessment (EA) and final Finding of No Significant Impact (FONSI) associated with the proposed license amendments.

Later on page 18082, the NRC restates its summary in the Findings of No Significant Impact.

> The NRC is proposing to amend Renewed Facility Operating License Nos. DPR–44 and DPR–56 for PBAPS, Units 2 and 3. The proposed amendments would authorize an increase in the maximum reactor power level from 3514 MWt to 3951 MWt. The NRC has determined not to prepare an Environmental Impact Statement for the proposed action. The proposed action will not have a significant effect on the quality of the human environment because, amending the licenses with the higher maximum reactor power level, will not result in any significant radiological or non- radiological impacts. Accordingly, the NRC has determined that a Finding of No Significant Impact (FONSI) is appropriate. The NRC's Environmental Assessment (EA), included in Section II above, is incorporated by reference into this finding.

The publication was dated March 31, 2014. Six weeks later, the Peach Bottom nuclear plant was placed on the NRC's priority list of 10 nuclear plants in the Central and Eastern United States that have to do more detailed risk evaluation from an earthquake. Peach Bottom was chosen for an expedited evaluation based on updated information about the possibility of localized earthquakes. If ground movement from the an earthquake based on the new information exceeds what was used when the plant was designed, Peach Bottom will have to conduct a detailed analysis to determine any changes in accident risk from a quake by December, 2014. Exelon will have to complete an "expedited approach" review to evaluate and reinforce key core cooling equipment to make sure the plant could safely shutdown if a quake hit at the level now considered possible.

Paradoxically, a sliding scale of standards was applied to on June 3, 2014, relating to the relicensing of the Muddy Run is also owned and operated by Exelon. The 800 MWt hydroelectric station is located on the eastern shore of the Conowingo Pond on the Susquehanna River in Lancaster County. The project has operated since 1966.

The Department of Environmental Protection announced that it has issued a water quality ("WQ") certification for the continued operation and maintenance of Exelon's Muddy Run hydroelectric project in Martic and Drumore Townships in southern Lancaster County.

Pennsylvania WQ certification is required for relicensing by the Federal Energy Regulatory Commission for projects like the Muddy Run Project under the Federal Power Act. WQ certifications are authorized under the Federal Clean Water Act, the Pennsylvania Dam Safety and Encroachments Act and the Pennsylvania Clean Streams Law.

The hydro plant that is owned by Exelon and produces 22.4% of the electricity of its nuclear sibling agreed to make substantial commitments to mitigating the aquatic resource impacts of the project. While DEP and the NRC gave Exelon a free pass on the EPU at Peach Bottom, the same company acknowledged that in order for the Muddy Run project to continue operation and to minimize the effects of the facility on aquatic resources, Exelon had to agree to:

• Provide $500,000 per year for 16 years for agricultural pasture and barnyard best management practices to address sediment introduction and other habitat improvement projects, such as stream improvement projects, riparian buffers and small dam removal in Lancaster and York counties.

• Provide a version of Exelon's computer model for evaluating river flows on the Lower Susquehanna River to the Susquehanna River Basin Commission.

• Provide $8 million over 16 years by Exelon to the Lancaster and York County conservation districts.

In contrast, the NRC is entertaining a request by Exelon's to postpone flood reevaluation for peach Bottom 2 & 3 - due on March 12, 2014 - **until March 12, 2015.** Exelon discussed the milestones for completion of the flooding hazard reevaluation as follows in a letter to the NRC on March 12, 2104.

a) Complete recalibration of the watershed model by the end of May 2014.

b) Complete development of the scenarios for the Probable Maximum Flood at PBAPS, Units 2 and 3, by the end of July 2014.

c) Complete the calculations of flood levels and associated effects based on Appendix H to NUREG/CR-7046, "Design-Basis Flood Estimation for Site Characterization at Nuclear Power Plants in the United States of America," by the end of December 2014.

d) Start internal Exelon review of the PBAPS flooding hazard reevaluation in mid-January 2015.

e) Submit PBAPS flooding hazard reevaluation to the NRC by March 12, 2015.

(NRC, Richard B. Ennis, Senior Project Manager Plant Licensing Branch 1-2 Division of Operating Reactor Licensing Office of Nuclear Reactor Regulation, May 21, 2014)

VIII. Conclusions:

Power generation, cooling and safety are inherently connected. There is no fence between generation and safety. And there should be no regulatory moat created by artificial safety definitions erected by nuclear generators. The lack of regulatory coordination establishes a deleterious precedent, and constitutes *de facto* approval of grandfathered and outdated regulations.

Even more baffling are the regulatory moats that federal and state agencies erect to protect rigid and exclusive zones of interest. This type of laissez-faire regulatory behavior gives rise to undesired corporate behaviors such as “grandfathering" and “back fits,” deterioration of monitoring equipment, time delays causing avoidable leaks, and waivers for monitoring wells.”

Populations long the Susquehanna River are potentially impacted by contaminated water, liquid-release exposure pathways, irrigated crops and external exposure during recreational activities.

The Final Safety Evaluation analysis must factor the entire Peach Bottom Region which includes Delaware, Maryland and Pennsylvania and the Chesapeake Bay - largest estuary in North America.

The NRC staff must also review dated and delayed submissions, reconcile “grandfathered” regulations and clarify general and vague assumptions.

The proposed Extended Power Uproot License Amendment for the Peach Bottom Atomic Power Station Units 2 & 3 should be held in abeyance until all the open and unresolved environmental, health and safety issues identified in this Testimony have been addressed and closed out.

Respectfully Submitted,

Eric Epstein, Chairman
Three Mile Island Alert, Inc.
4100 Hillsdale Road
Harrisburg, PA 17112
(717)-541-1101

Service list:

Environmental Protection Agency
Exelon Generation
Pennsylvania Department of Environmental Protection
Pennsylvania Fish and Boat Commission
Pennsylvania Historical and Museum Commission
Pennsylvania Public Utility Commission
Susquehanna River Basin Commission
U.S. Army Corps of Engineers
U.S. Fish and Wildlife Service
U.S. Nuclear Regulatory Commission

Dated: June 10, 2014