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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

March 21, 2008

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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SUBCOMMITTEE ON POWER UPRATES

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FRIDAY, MARCH 21, 2008

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ROCKVILLE, MARYLAND

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OPEN SESSION

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

SUBCOMMITTEE MEMBERS PRESENT:

SAID ABDEL-KHALIK, Chair

MARIO V. BONACA

SANJOY BANERJEE

J. SAM ARMIJO

OTTO L. MAYNARD

JOHN D. SIEBER

CONSULTANTS TO THE SUBCOMMITTEE PRESENT:

GRAHAM WALLIS

TOM KRESS

ALLAN PIERCE

NRC STAFF PRESENT:

ZENA ABDULLAHI, Designated Federal Official

JOHN G. LAMB

KAMAL MANOLY

TOM SCARBROUGH

VIKRAM SHAH

PAT HYLAND

BOB PETTIS

MARTY STUTZKE

DONALD HARRISON

MATTHEW MITCHELL

MATT YODER

ALSO PRESENT:

PAUL DAVISON
BILL KOPCHICK
ED BURNS
PAUL DUKE
FRAN BOLGER
BRIAN MOORE
SHELLY KUGLER
ALAN BILANIN
ED SCHROLL
ALEX BOSCHITSCH
SAMIR ZIADA
STEVE HAMBRIC
BRANDON SWARLEY

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

8:30 a.m.

CHAIR ABDEL-KHALIK: The meeting will now come to order.

This is the second day of a two day meeting of the Advisory Committee on Reactor Safeguards Power Uprate Subcommittee's review of the Hope Creek Generating Station extended power uprate application.

The purpose of this meeting to hear presentations by and hold discussions with the Hope Creek licensee, PSEG, the NRC staff, their consultants and other interested persons regarding the proposed EPU.

The Subcommittee will gather information, analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberation by the full Committee.

Zena Abdullahi is the designed Federal Office for this meeting.

Parts of this meeting will be closed because the material to be presented is considered priority by the applicant and/or its contractors, General Electric-Hitachi and Continuum Dynamics Incorporated.

The proposed times for the closed sessions are identified in the agenda.

Attendees who are required to leave during the closed sessions can call 301-415-7360 to obtain a status report as to when they can rejoin the meeting.

We received the request for a teleconference from Mr. Jerry Humphreys who represents the State of New Jersey. A bridge telephone number was made available.

Having signed the relevant proprietary agreement with Continuum Dynamics Incorporated. Mr. Humphreys should be able to participate in today's closed session discussions of the steam dryer based on CDI's analyses and methodologies. Please note that the bridge connection is only for listening in.

A transcript of the meeting is being kept and will be made available as stated in the *Federal Register* notice. It's requested that speakers first identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

Before we get started, I'd like to point out that based on yesterday's presentation there appears to be an error in section 1.5 of the Safety Evaluation Report where the statement is made that independent confirmatory calculations were performed by the NRC staff on long term containment temperature response for a LOCA.

MR. LAMB: This is John Lamb of the NRC.

We agree with that assessment and it does not change your conclusions of the safety evaluation.

CHAIR ABDEL-KHALIK: Thank you.

We will now proceed with the meeting. And I call upon PSE&G to start the meeting.

MR. DUKE: Thank you, Mr. Chairman. This is Paul Duke.

There were a couple of items for which we said we would provide additional information from yesterday's meeting, one having to do with exit quality and the other having to do with SRV and ECCS operating experience. And I would ask General Electric to address the first issue.

MR. MOORE: This is Brian Moore of Global Nuclear Fuel.

The question was given a core average exit void fraction, exit void fraction of 77 percent, what is the quality. And that would be about 20 percent, slightly higher in the periphery. And this is before mixing with the bypass.

CHAIR ABDEL-KHALIK: Thank you.

MR. DAVISON: Okay. I'd like to continue

on with the follow up information, the first topic being the question regarding the licensee's ability to ensure that the analysis required over pressure protection is maintained.

A brief description of Hope Creek's 14 safety relief valves, you see the four or five and five sets of different pressures with the associated plus and minus 3 percent tolerances that go along with those SRVs.

We did in 1998 a -- tech spec change. Hope Creek, like many other sites, were experiencing repetitive out of tolerance setpoint test results.

Additionally, we proceeded with the industry on the next page through the Boiling Water Owners' group implementation of changes to improve our safety relief valve performance. The setpoint repeatability and the main seat leakage were both addressed through modifications and improved maintenance practices.

Under the SRV performance, that's post-1998 when we changed from 1 percent to 3 percent tolerance, you'll see the number of failures and the various tolerances that were exceeded listed for cycle 8 through 13. The modification and maintenance practices were implement, as the dotted line shows, in the 2006 refuel outage. Our last refuel outage, which was September of 2007, we removed valves and performed setpoint testing for tech specs. You see that the modifications that were done both the Stellite-21 pilot valve upgrade as well as the more refined maintenance practices with respect to seat lapping has paid off with zero failures of our first round of testing following our modifications.

Although the modifications appear to be successful, our continued testing each refuel outage will closely monitor those valves to ensure that the results are consistent.

When we do have failures we're required per our tech specs to submit any LER for greater than one valve should it vale or outside the tolerance. And that requires an assessment of the over pressure protection capability.

GE performed a bounding analysis that included one nonfunctional safety relief value. That's permitted by tech specs. And 13 of the remaining, all of the remaining which are 13 SRVs set to lift at 1250 psig, which correlates to approximately 7½ percent greater than the highest range setpoint as allowed by the plus 3 percent tolerance. The results of that did conclude that there is positive margin to ensure that we continue to have the over protection.

Additionally, margin not included in this bounding analysis still exists due to the low feature on two of the SRVs that Bill Koopchick spoke about yesterday in his operations presentations. Essentially that's at 1047 spig, two of our SRVs, the Hotel and Papa or H&P SRVs control automatically at a lower pressure. Again, that credit was not applied to that bounding analysis.

So in conclusion, the SRV performance deficiencies were recognized. We did pursue improvements through the industry. We implemented the modifications and we have seen improved results with respect to our surveillance setpoint checks of the SRVs.

MEMBER BONACA: The reason why I asked the question yesterday was because the concern that flow-induced vibrations may deteriorate performance further.

MR. DAVISON: Correct.

MEMBER BONACA: Do you have any information regarding sister plants that have in fact have operated and how their performance of the SRVs has changed because of that?

MR. DAVISON: We do. We did benchmark

specifically for that concern. We had the data from Quad Cities, who had instrumented their electro-matic relief valves. And, in fact, that is why we have our SRVs, both the body of the SRVs at the pilot valve--

MEMBER BONACA: Yes.

MR. DAVISON: -- and also at the tailpipe for vibration so that we have our baseline data, which is well below the .1 g RMS value, and we don't expect it to go anywhere near that specific limits.

MEMBER BONACA: You say for sister plants performance has not degraded? Going up? You don't know?

MR. DAVISON: Based on set point tolerances?

MEMBER BONACA: Well, in general, yes. Well, that would be the issue?

MR. DAVISON: Do we have specific information on that that we can provide right now?

We have the general benchmarking, but with respect to failures or setpoint changes coming out of EPU we have not seen a trend. But I don't have that specific information. We can certainly follow up with that.

MEMBER BONACA: It would be valuable.

MR. DAVISON: Yes.

Other questions on SRVs?

We have the follow up just to specifically identify plants that have previously updated to see if they've had any degradation or change in their SRV performance with respect to setpoints or tailpipe leakage.

MEMBER BONACA: I got it. That's good.

MR. DAVISON: Okay. A similar question was asked of the ECCS system with regard to the ECCS system operation and reliability to support the licensing and design functions. Tech specs govern operation with combination of HPIC, RCIC, RHR and core spray being out of service.

Both of our high pressure and low pressure system unavailability, which we track and report, is closely guarded and monitored at Hope Creek. We continue to have top quartile performance, which is the norm for the station, and the number is listed there.

And finally, our quarterly IST flow tests of the pumps mentioned and the training of those results have been satisfactory. And, in fact, we have no pumps on increased frequency, which would be a sign of some of type degradation. So there are no pumps in that category.

CHAIR ABDEL-KHALIK: Thank you.

MR. DAVISON: You're welcome.

CHAIR ABDEL-KHALIK: Are there any questions about these two issues?

We will now proceed with the normal presentation, which is item 15 on the agenda.

MR. DAVISON: And I failed to introduce myself when I started. My name is Paul Davison and I'll actually in this session be discussing the Hope Creek reactor vessel internals and the steam dryer.

This is an open session, which will be followed by a closed session to discuss proprietary information.

Starting with reactor vessel internals, I'll discuss the EPU, effects on neutron fluence, flow-induced vibration, structural integrity, IGSCC and vessel internal inspection programs.

On page 3, start off with the IASCC or irradiation-assisted stress corrosion cracking. The increase in fluence did not result in additional components exceeding the threshold for IASCC. In fact, the shroud, top guide and the dry tube assembles all previously exceeded the IASCC threshold.

With specifics on the shroud, it is inspected in accordance with BWRVIP-76. In 1997 baseline inspection was completed with no flaws. The ten year inspection was completed in 2007. Six minor flaws were identified that did not impact structural integrity. Reinspection is scheduled for ten years, which is the norm for BWRVIP-76.

The top guide inspection, it will be conducted in accordance with the recently issued BWRVIP-183 documentation. And that will commence in our next outage, which is in the spring of 2009. Four locations will be inspected in 2009 with ten percent of all the locations being completed within 12 years per the guidelines that are outlined in the VIP documentation.

And the incore dry tube assemblies, all 12 dry tubes were replaced in the year 2000. And that was due to cracking. Less susceptible material was utilized during the replacement, and we will continue to inspect for the GE SIL 409 requirements, which is a 20 year.

MEMBER ARMIJO: What will you do if you find some indications in the top guide there of concern? Do you have a repair --

MR. DAVISON: There are a few plants. I believe it's Oyster Creek and Nine Mile 1 that have started the inspections. We have done previous inspections, not to any great quality. You know, more of a kind of general overview of the top guide.

A single top guide beam failure or indication would not result in loss of geometry. Multiple would, in fact, do that. We do not have any specific contingency plans on our books, but part of our outage planning process will go out to look at other operators as well as General Electric to come up with contingency, either flaw handbook-type analysis to say what's good or what's not good and then the potential fixes that would have to be implemented to address anything that was found.

MEMBER BONACA: Well, what's the condition of your shroud?

MR. DAVISON: The shroud has minor flaws, as I mentioned.

MEMBER BONACA: Okay.

MR. DAVISON: The shroud itself was inspected in '97, zero flaws. 2007, re-baselined and we have five flaws, five minor flaws that didn't impact the structural integrity.

MEMBER ARMIJO: How do you define minor, just to calibrate?

MR. DAVISON: Minor in that --

MEMBER ARMIJO: About an inch long or--

MR. DAVISON: Yes. Some details on them. All less than 2 inches in depth, less than 15 percent throughwall. And then, you know, each one is a little bit different where it is, but in general that's the criteria. None of them exceeded that.

Okay. On the next slide, RPV internals.

The vessel internals are not adversely impacted by EPU operations.

Hope Creek vibration levels were extrapolated for operation at percent above the 3952 megawatt thermal which a maximum rated core flow of 105 percent. So highest power and flow conditions.

All components were well below GE's acceptance limit of the 10,0000 psi. In addition, the jet pump sensing lines met the acceptance criteria of no resonance with recirc pump vane passing frequency.

MEMBER ARMIJO: What is the resonance frequency for these sensing lines?

MR. DAVISON: There's actual several of them. We validated during construction through finite element modeling as well as impact tests. We did have some criticals on 10 and 11 and 20 and jet pump 1, which are closest to the N1 recirc outlet nozzles. We also added a support to jet pump sensing line 11.

Do you have the specific frequency?

MR. DUKE: I'd have to look up.

MR. DAVISON: Okay.

DR. WALLIS: Is it only the sensing lines you worry about? These recirc pump event passing frequency as is spread out throughout the whole system, isn't it?

MR. DAVISON: Yes, that's correct. But for the vessel internals perspectives, that's one of the major --

DR. WALLIS: These are the only lines you worry about for resonance?

MR. DAVISON: Internal to the vessel, yes.

DR. WALLIS: Only internals you worry about for resonance?

MR. DAVISON: Yes. The recirc piping, RHR piping, mainsteam line piping in the drywell is also being monitored via accelerometers that we talked about and we'll actually talk about it again with respect to dryer impact. But for the actual vessel internals, these are the only physical lines inside the vessel from the wall of the vessel to the jet pumps themselves, for the calibrated jet pumps.

Page 5. The RPV is not adversely impacted by EPU. The RPV components were screened against the criteria of fatigue usage factor in essence of 0.5.

Three components required further evaluation. The main closure studs, the core shroud support and the core spray nozzle. Actually two of them, N5 alpha and bravo. All were analyzed to meet the requirements of ASME code with respect to stress and fatigue.

The three RPV nozzle weld overlays, we had one in '04, '07 and 1997, have all been modified and analyzed to be acceptable for EPU conditions. In fact, we did weld overlays on those three individual cases.

MEMBER ARMIJO: What is the maximum fatigue usage factor calculated for these components?

MR. DAVISON: For the studs, it was .755. For the core spray nozzle it was .796. And for the shroud support was .672.

MEMBER ARMIJO: Thank you.

MR. DAVISON: You're welcome.

MR. DAVISON: Okay. I'll move on to IGSCC on page 6.

Hope Creek's IGSCC program is not being changed by the implementation of EPU. There was a negligible change in the stress component. There are no material changes. And the corrosive environment changes will be mitigated via hydrogen adjustments, hydrogen injection adjustment rate -- hydrogen injection rate adjustments to compensate for the increased oxygen generation at the higher power level.

MEMBER BANERJEE: How are the spargers arranged? Do they go all the way around?

MR. DAVISON: Core spray spargers?

MEMBER BANERJEE: No. I mean for the feed water. Don't you have spargers that distribute them?

MR. DAVISON: Yes.

MEMBER BANERJEE: And hydrogen is injected where exactly?

MR. DAVISON: Hydrogen is injected into the suction of the secondary condensate pumps. So it travels through the feed water system and is injected through the spargers.

MEMBER BANERJEE: Right. So do these spargers go all the way around or only partially the way around?

MR. DAVISON: They don't go 360. There's no individual lids, there is a gap on each end of them. I don't know if we have an actual picture of that. But they're not connected or 360 all the way around, but they're close to it.

MEMBER BANERJEE: And you have good evidence that the hydrogen mixes?

MR. DAVISON: Well, we were measuring our

ECP for protection that shows us that we've got good protection as far as running in the minus 489 to 490 ECP range.

We also are pursuing -- right now our analysis allows us to inject down to approximately 25 percent. We're actually pursuing modifications to our hydrogen water chemistry system as well as licensing change to allow us to inject down to 200 degrees so we can get more injection, more protection during startup phase of the vessel itself.

MEMBER BANERJEE: So now you're injecting more hydrogen for this few or --

MR. DAVISON: Yes. Going back in time a little bit when we first started injecting to get partial mitigation, we were in the approximately 30 scfm range. In 2006 during the refuel outage we applied nobel metal, we had a noble metal chemical application. Coming out of that we reduced our hydrogen rates to approximately 8 scfm. So from 30 down to 9, which also resulted in a significant radiological reduction.

Coming out of EPU, when we get to EPU power we will doing a full range of hydrogen injection testing for mitigation purposes. Are projections say that we will move from 9 to approximately 13 scfm. We think our endpoint will be 13 scfm. So approximately 4 additional scfm.

MEMBER BANERJEE: How do you measure the effectiveness of this hydrogen chemistry? Is there some quantitative measure?

MR. DAVISON: Through chemistry testing and also through our installed ECP and durability monitors that we installed as part of the nobel metal chemical application.

MEMBER BANERJEE: And where are these monitors?

MR. DAVISON: Reactor water cleanup system. They take samples off of reactor water cleanup. So vessel-to-vessel water is what we're checking.

MEMBER BANERJEE: Okay.

MR. DAVISON: Page 7. In addition to the previously mentioned top guide inspection that I talked about, we'll also be following up with components in our inspection program and don't anticipate any effects related to EPU. Specifically the wedges, our jet pump wedges will be inspected in accordance with BWRVIP 41. The feedwater sparger and end brackets will continue to be inspected, as well the shroud head bolts.

And if there are no additional questions on internals, I'll transition over to the dryer.

MEMBER BANERJEE: Could you just give us an idea of how the feedwater spargers are arranged and is it --

MR. DAVISON: Do we have a picture of the feedwater spargers that we can provide? That would probably be the easiest thing to give you. We'll provide that.

MEMBER ARMIJO: Please proceed.

MR. DAVISON: Page 8. Okay. The open discussion will cover the dryer's design, the design margin and the power ascension test plan associated with the steam dryer.

The industry experience related to steam dryer failures is associated with plant specific dryer design, the main steamline piping velocities and acoustic resonance attribute to the main steamline piping configurations themselves. So in this morning's discussion we'll emphasize Hope Creek's robust design characteristics and our ample margin that exists.

I'd like to start off on the next slide just talking about the dryer itself.

Hope Creek's steam dryer was manufactured to the ASTM material standards, the ASME welding standards and General Electric's design criteria to ensure structural integrity. However, it is not a safety related component.

Hope Creek's curved hood dryer is the third generation of steam dryers designed by General Electric. It's an improvement over the square hood design that failed Quad Cities. The curved hood design creates less turbulent steam flow through the dryer and into the main steamlines, which reduces dryer operating stresses. That will be in detail in the closed session.

Additionally, the dryer design was enhanced prior to initial operations at Hope Creek.

CHAIR ABDEL-KHALIK: What was the modification for that modification at the time?

MR. DAVISON: At the time, and actually cover that on the next slide, but it was driven by industry operating experience. And I'll go actually through every modification that we did on the next slide.

We have implemented the requirements of BWRVIP-139 for inspections. The baseline inspections were completed during the RF-12 and 13. So the prior two outages to last year's fall outage.

So I'll go to slide 10 right now and actually show the actual modification.

MEMBER BONACA: How long have the operations been going on with this when you did the inspection?

MR. DAVISON: Well --

MEMBER BONACA: How long had the dryers been in operation when you did the inspections?

MR. DAVISON: From initial operations in '86 to the 2004. The whole operating life of the plant. Once we modified the dryer and installed it and started up the plant, we had not touched the dryers as far as modifications, with one minor exception that I'll talk about right now.

This is a picture of the steam dryer with pre-operational enhancements that I talked about mods shown in the red colors. The General Electric approved modifications were installed to address operating experience specifically from Toaki and, actually, Susquehanna.

The outer hood material thickness was increased from 1/8th inch to 1/2 inch. The center outlet plenum material thickness was increased from 3/16th to 1/2 inch thickness. The tie bars on top, the material thickness was increased from 1/2 inch by

1 inch cross section to 2 inch by 2 inch cross section. And we increased the number of the tie bars from 23 to 37.

The inner and middle hood to end plant joints were reenforced with external strips and internal backing welds. The strips are 3/16th by 2 inch wide stainless steel that were welded to the end of the hood but overlapping the joint to the end plate. The back weld was performed on the inside of the hood for additional strength. Obviously, we could do this because it was not irradiated. It was before we did initial operations.

And finally, the dryer leg support leg located on the internal diameter of the vessel not shown on this picture were leveled to prevent dryer rocking. And we actually did conformational tests prior to startup so we didn't have an uneven sitting dryer.

No other modifications or repairs have been made since startup with the exception of the lifting rod. Can we point that out? The lifting rod bracket, which was removed in our refill outage 12 that was due to a mishandling event. We actually caused a crack so we removed it.

The steam dryers' original design and

subsequent enhancements result in a very robust design for our EPU load conditions.

Okay. Now I'd do a little --

DR. WALLIS: The unused dryer which was tested --

MR. DAVISON: Yes.

DR. WALLIS: -- was that the same as this? Did it have the same modifications or what was it like?

MR. DAVISON: The steam dryer that was essentially abandoned, but we still had it, did not have all these modifications put into it since it was never --

DR. WALLIS: And it was the original dryer?

MR. DAVISON: That is correct. Nonmodified, yes.

This slide shows a comparison of Vermont Yankee, Quad Cities and Susquehanna units as compared to Hope Creek.

CHAIR ABDEL-KHALIK: But how do these modifications compare with the new Susquehanna dryer design?

MR. DAVISON: Well, I believe the design itself is different versus just an updated with these mods.

Do we have the specifics of Susquehanna's -- or GE's design?

MR. PIERCE: Can I ask a question? Allan Pierce, ACRS consultant.

Do you have access to that sort of information as to what Susquehanna does? Do you know? Is it something that you've driven to --

MR. DAVISON: We do not have the specifics. We do not have the specifics of the actual dryer itself.

MR. PIERCE: Okay.

MR. DAVISON: We know in general the things that they were focusing on for improvement.

DR. WALLIS: Well, we could ask GE.

CHAIR ABDEL-KHALIK: Is there anyone from GE who could answer this question? Okay.

MR. DAVISON: If it would please the Subcommittee, we can do further research with GE and see if we can get that information.

CHAIR ABDEL-KHALIK: That would be very helpful. Thank you.

MR. DAVISON: Okay to continue?

MR. PIERCE: If I could ask a question?

MR. DAVISON: Sure.

MR. PIERCE: On your fourth column there you say "MSL branch line legs." I'm not familiar with all your terminology, but it seems like in Quad Cities there was something that resonated off the -- why didn't you have that mentioned in your table there?

MR. DAVISON: I'll actually go through that right now.

MR. PIERCE: Okay.

MR. DAVISON: We're going to talk about the differences of both Quad Cities and Susquehanna.

It may seem like branch legs is a little bit more generic design, which we don't have.

MR. PIERCE: Right.

MR. DAVISON: The electro-matic relief resonance to the stand pipes for those relief valves were specific to Quad Cities. But I'll cover both of those actually.

MR. PIERCE: Okay.

MR. DAVISON: So walking through this specific table here of the Hope Creek comparison to the other facilities, our flow velocity, steam flow velocity is comparable to Vermont Yankee and the Susquehanna unit, but significantly lower than Quad Cities.

Quad Cities experience acoustic resonance at approximately 130 to 150 Hertz attributed to their electro-matic relief valve stand pipes. At CLTP Hope Creek does not experience any acoustic resonance. The Hope Creek SRV stand pipe diameters are larger, nominally 8 versus 6 inches at Quad and our main steamline flow velocities are lower, making us less susceptible to that whistling effect across the stand pipe.

The larger diameter and lower velocity results in the lower predicted stand pipe resonance. So, again, we will be monitoring that on our power ascension.

Susquehanna experienced acoustic resonance down at the 15 Hertz range. And that's attributed to the main steamline branch dead legs. Hope Creek does not utilize the main steamline dead legs for SRV connection pointed and does not experience the low frequency resonance.

So overall, Hope Creek --

MEMBER BONACA: Excuse me. Is it clear that Susquehanna is due to that or is it vortex shedding? Is there a clear understanding of this 15 Hertz --

MR. DAVISON: Yes. In fact, we'll be showing some information in the proprietary session that compares the actual steam lines with dead legs and without where you see the specific change. And that will be covered in the proprietary session.

So overall Hope Creek's lower steam velocity, absence of the main steamline branch dead legs and the curved hood design results in no main steamline acoustic resonance experiencing at CLTP. And this will be closed monitored during the power ascension and we'll cover it in greater detail in the closed session.

I'd like to just show a picture of our configuration for comparison. And not compared here are the different size for the stand pipes to Quad Cities, but it does specifically point out the dead legs.

The actual flow path for the steam, the steam dryers positioned with its vane banks approximately perpendicular to the main steamline nozzles. Alpha and bravo main steamlines are shown to the right, and the mirror images on the charlie and delta, or C and D, are on the left.

There are 14 Target Rock two-stage safety relief valves with identical stand pipe configurations. The alpha and delta main steamlines each of three SRVs, while the bravo and charlie each have four SRVs.

Also note that the bravo main steamline has a blanked off stand pipe for a spare SRV location which is not used.

As discussed in the previous slide, we have no dead legs. However, you see in the dashed lines we show the specifics of where the dead legs and the SRVs would be mounted at Susquehanna. That's just for comparison, but we do not have that.

After the main steam stop valves, which are just beyond the outboard MSIVs, the main steamline diameter increases from 26 to 28 inch nominal, which is an atypical feature. This reduces flow and reduced vibration in the main steamlines.

For reference, our main steamline strain gauges are located, and the drawing's a little tough but we just wanted to show relatively height of the main steamlines in correlation to the vessel, on the upper and lower locations depicted here in the picture, the red lines.

CHAIR ABDEL-KHALIK: So the steamline velocities that you presented in the previous table correspond to which part of the steamline? The 26 inch or the 28 inch?

MR. DAVISON: That's at the 26 inch

closest to the vessel where it impacts the vessel or the dryer ultimately.

MEMBER BANERJEE: Before the SRVs?

MR. DAVISON: Before the MSIVs.

MEMBER BANERJEE: Yes. Yes,also the SRVs, right?

MR. DAVISON: Yes. Through the steamline where the SRVs are located, that is correct.

MR. PIERCE: Can I ask a question?

MR. DAVISON: Yes.

MR. PIERCE: The steam dome, is that the top right, is that where it is, where the exit for the steam dome is? I'm trying to understand the figure.

MR. DAVISON: Yes. The smaller figure?

MR. PIERCE: Yes.

MR. DAVISON: That's a side review of the reactor vessel where the main steamline nozzles exit at the top and run down to where the SRVs are.

MR. PIERCE: Okay.

MR. DAVISON: So on top --

MR. PIERCE: Where are the strain gauges, two horizontal red lines?

MR. DAVISON: At each location where the redline intersects the main steamline, we have a band of eight strain gauges. So eight per those four locations that are shown there.

MR. PIERCE: Are they circumferential?

MR. DAVISON: Yes, 45 degrees apart all the way around.

MR. PIERCE: Okay.

MEMBER MAYNARD: Okay. Back on that figure, just for the record I need to point out that the lettering on the handout shifted.

MR. DAVISON: Yes.

MEMBER MAYNARD: And so it'll end up in the record, you need to clarify that a little bit.

MR. DAVISON: Thank you. Yes. The B dropped down and shifted everything over so they don't line up. The correct orientation, which is on the slide, is C, D, A, B or charlie, delta, alpha, bravo.

Thank you.

CHAIR ABDEL-KHALIK: So if we go back to the table. Now this 167 feet per second corresponds to your 15 percent EPU, which is 116.6 original licensed power?

MR. DAVISON: Correct.

CHAIR ABDEL-KHALIK: The value given for Susquehanna is for their 20 percent power uprate.

MR. DAVISON: Correct.

CHAIR ABDEL-KHALIK: If at a future time

you were to go to a full 20 percent power uprate, what would be your main steamline velocity?

MR. DAVISON: I don't think we have that. We have not projected that out.

CHAIR ABDEL-KHALIK: Go to a microphone.

MR. BILANIN: Alan Bilanin from Continuum Dynamics Incorporated.

It's because it's a cost and pressure power uprate, power is a pressure times flow rate. Flow rate is velocity times cross sectional area. Five percent increase in power is a five percent increase in velocity in the main steamline.

CHAIR ABDEL-KHALIK: As long as the feedwater temperature remains unchanged.

MR. BILANIN: But that's minor change.

MR. DAVISON: Susquehanna also did a stretch uprate, so they changed their actual dome pressure as well.

CHAIR ABDEL-KHALIK: The point I'm trying to make is that if that is the case, it would be significantly higher than Susquehanna's main steamline velocity?

MR. DAVISON: Correct.

CHAIR ABDEL-KHALIK: Thank you.

MEMBER SIEBER: What was the actual one

that was for the amount of power increase that you decided to put into this amount, what was the limiting feature of the plant?

MR. DAVISON: The limiting feature is the high pressure turbine at this point. In fact, our high pressure, even the modified high pressure turbine will currently limit us to 111.5 percent power. We are going to need to assess further modifications to get to the license requested 115 percent power.

MEMBER SIEBER: Okay.

MR. DAVISON: In addition to that we have cooling tower. In summer operations we'd be cooling tower limited, so we'd also have to look into putting a helper tower or some other change that would allow us to lower our circ water temperature for our condenser.

MEMBER SIEBER: So those are pretty capital intensive --

MR. DAVISON: That is correct.

MEMBER SIEBER: Right. So that's why you chose to uprate as far as you did?

MR. DAVISON: Correct. Originally we started out at a 20 percent uprate and through the analysis phase of that back in the early 2000s got to 115 because of that.

MEMBER SIEBER: That sounds reasonable. Thank you.

MR. DAVISON: You're welcome.

Page 13, Hope Creek utilized Continuum Dynamics Incorporated or CDI to perform the steam dryer analysis. This includes the Revision 4, the acoustic circuit model for the steam dryer load definition as well as the finite element analysis for modeling for the steam dryer stresses. This table represents the four lowest stress ratios for both the alternating and peak stresses. ASME code requires both alternating and peak loads to be evaluated.

Stress ratio here is defined as the allowable stress divided by actual stress, therefore the ratio with the lowest numerical value is the location with the lowest stress margin.

The alternating stresses are the most importance since they change with acoustic loads impacted by EPU and can lead to fatigue damage.

On this table are the four lowest of each of the alternating end peak. All other locations that were analyzed have a stress ratio about 2.5

The results of the steam dryer analysis performed at 115 percent show that lowest predicted alternating stress ratio is 2.8 with all the biases and uncertainties included. This stress ratio located at the outer hood vane bank is predominately a result of flow induced vibration.

The lowest peak stress ratio is 1.58 at the skirt location. Peak stresses are related to the support of the structure's dead weight. And that peak stress is dominated by the actual dryer's weight, 80,000 pounds, and shows negligible change at EPU.

The alternating stress ratio at this location is 9.36 in comparison to its peak and further supports the dryer dead weight is the dominating factor in the peak stress ratio location.

Hope Creek's stress values are shown at actual EPU conditions. All other locations have stress ratios greater than 2.5 as previously mentioned.

In past presentations at the ACRS Subcommittee by other utilities these ratios were discussed as a function of CLTP, therefore these stress ratios are well above allowable levels and consider margin at EPU. Of course, the assessment and how those numbers were derived will be covered in the closed session.

DR. WALLIS: Explain again what shift means.

MR. DAVISON: Oh, thank you.

When we did all the analysis or CDI did all the analysis, to further look a that analysis they did a frequency shift at every point from between minus 10 and plus 10 and looked for what the worse value was, and that's the one we used.

So the shift that's listed there just happens to be the point --

DR. WALLIS: The frequency, that's the amount, the frequency shift to give the maximum --

MR. DAVISON: Correct. Correct.

DR. WALLIS: Okay.

MR. DAVISON: So in that plus to 10 and the minus 10 band we picked the highest one to represent that particular location.

Okay. The power ascension testing. From a monitoring perspective we talked a lot about this yesterday. In fact, why don't you put that slide back up. I think it'd be better if we talk to the slide we talked to yesterday, which we've updated.

What was on this slide is that we have strain gauges, accelerometers and we're going to be doing moisture carry over. A lot more testing will be done, as you'll see in the spreadsheet that we have for the non-dryer related analysis and monitoring during the power ascension phase.

Each of the tests that we do, the strain gauges which -- excuse me. Strain gauges, accelerometers and moisture carry over all have two different levels of acceptance. Level two is -- below level 2 is just continue to do power ascension. There's nothing of concern. If we reach a level 2 limit, that is a hold point. We have to stop and do analysis before we could continue power ascension.

If we hit a level 1 criteria, that would be stop, return the unit back to the previously acceptable power and then do analysis to determine what's next.

DR. WALLIS: Do you know how to predict moisture carry over when you change the change steam flow rate by 16.6 percent?

MR. DAVISON: Well, we've looked at other operating experience. Like Vermont Yankee I think increased by a factor of six. So we're bounding it with that.

DR. WALLIS: But it's empirical? You go from experience with other dryers? It's not as if you try to predict the carry over theoretically, is that true? It's all based on experience?

MR. DAVISON: Shelly?

MS. KUGLER: No. We actually do take

readings.

MR. DAVISON: No. Predict.

DR. WALLIS: Do you know how to predict it?

MS. KUGLER: Oh, no. We do not know how to predict.

This is Shelly Kugler.

No, we do not predict what it's going to be, we're not sure what it's going to be.

DR. WALLIS: But you have to have some idea what it's going to be, because then you have some idea if you've got something which is out of the ordinary which you didn't expect.

MR. DAVISON: Right.

DR. WALLIS: So you must have some prediction, but it's not a theoretical prediction.

MR. DAVISON: Yes.

DR. WALLIS: I think what you're telling me is it's a empirical prediction based on experience with other plants.

MS. KUGLER: Right.

MR. DAVISON: Right. GE analysis was done. They analyzed our current operating condition at .05 percent and the prediction at EPU would be .18 percent. However, what we're also --

DR. WALLIS: So there's a lot more moisture carry over, like EPU?

MR. DAVISON: Well, the one difference is even though that's the predicted values, our actual operating and measured values is .005 percent.

DR. WALLIS: Is much less than predicted?

MR. DAVISON: Correct.

DR. WALLIS: So that's you're off by a factor of ten?

MR. DAVISON: That's correct. And then we bound that also with what we learned from the industry, Vermont Yankee being the factor of six that they went up.

DR. WALLIS: Yes. So you --

MR. DAVISON: All anticipated results expect to be below the .3 which we're designed to as the max limit.

DR. WALLIS: Yes. I'm just wondering, what you would call extraordinary. You get .005 now and when you go to EPU you expect something .006 or something, a slight increase maybe?

MR. LINDSAY: This is Paul Lindsay with Mainline Engineering.

The design numbers right now for moisture carry over for Hope Creek are .1 and have been evaluated up to and including .3. Those two respectively are the level 2 --

DR. WALLIS: These are percent?

MR. LINDSAY: Percent, correct.

DR. WALLIS: Point one what?

MR. LINDSAY: Point 1 percent.

DR. WALLIS: Of what.

MR. DAVISON: Of moisture.

MR. LINDSAY: Moisture.

DR. WALLIS: By flow rate?

MR. LINDSAY: So the design numbers are .1 and .3, however the operating experience, as Paul had mentioned, right now we are running .0058.

DR. WALLIS: Percent?

MR. LINDSAY: Percent.

DR. WALLIS: That's extraordinarily dry.

MR. LINDSAY: It is very dry at Hope Creek. And it's our expectation that we will not hit .1 percent during the power ascension.

DR. WALLIS: There's a huge change from .008 to .1? So how do you know what's unusual. Well, I'm just thinking. Suppose something breaks, you're looking for an unexpected increase in wetness.

MR. LINDSAY: That is correct. Part of our criteria is considering and looking for a 50 percent step increase over previous measured values.

MEMBER BANERJEE: How do you measure moisture?

MR. LINDSAY: I'm not --

MR. DAVISON: We perform weekly tests of moisture carry over. And chemical does it through the analysis of sodium-24.

DR. WALLIS: So it's something dissolved in the water that you get?

MR. DAVISON: Correct. And we actually do that test weekly. We'll be doing it much more frequently during EPU.

DR. WALLIS: So you get .0058 percent now. So what do you expect to get when you get full EPU? And you talked about .1, which is so different from .0058.

MR. LINDSAY: Right.

DR. WALLIS: I would say something had broken.

MR. LINDSAY: Our expectation would be that we would be below .1 percent --

DR. WALLIS: But there's such a big band between .0058 and .1. It's not a very good symptom.

MR. LINDSAY: Again, as stated earlier, considering the Vermont Yankee experience where they saw it behaved in a linear fashion and then once they achieved essentially 13 or 14 percent increase, they saw it moving up exponentially --

DR. WALLIS: That's because something broke? Is that because something broke?

MR. LINDSAY: No. That was under normal conditions.

DR. WALLIS: But there's a sudden increase anyway -- there's a sudden increase anyway without breaking anything just because of the design of the dryer. So how do you tell when your sudden increase is due to something breaking and when it's due to some phenomenon which just was there already?

MR. DAVISON: (1) we'll be doing the training so we'll be looking for changes, but it is a suite of things, of tests that we're going to be doing to monitor the dryer in addition to the strain gauges and accelerometer. So it's another way to trend and predict and monitor the dryer in addition to the strain gauge readings and the accelerometer on the main steamlines.

MEMBER ARMIJO: Is this moisture carry over a value that you currently measure typical of these dryers? That seems awfully good.

MR. LINDSAY: When you consider Vermont

Yankee started at .02, Hope Creek would be very good.

MR. PIERCE: I want to ask a question. I'm just curious about steam dryers and the technology for designing them. Is there any methodology for predicting when you design a steam dryer how much water it will take out of the steam, or is it just we hope for the best? Is there a science to it. That's a question I had. I don't know if you know the answer, it's just a rhetorical question. But I get the feeling there isn't.

MEMBER BONACA: It's not a rhetorical question. I think GE should try to answer that.

MR. DAVISON: Well, certainly there are design requirements for our piping and turbine systems that required the steam quality to be less than .3. So when it was originally designed. And I can only imply that there are criteria that they knew they had to meet so that we had a low enough steam or a moisture content to not impact or adversely impact our steam monitor or high pressure turbine.

MEMBER BONACA: I guess the issue is really how useful this moisture carry over is as a measure of the integrity of the dryer. It sounds like it's not particularly useful because you have really no theory to say what should be the baseline. So sometimes it goes linearly, sometimes it goes exponentially. So what does it matter?

MEMBER MAYNARD: Yes, I would agree with that. Because you're dealing with such low numbers to start with that a change makes -- you're just in such a small range there. Although I think there's plenty of other ways to measure. And moisture carry over is important for other considerations.

MR. DAVISON: Right.

MEMBER MAYNARD: I'm not sure how valuable it is as a monitor of the integrity of the --

DR. WALLIS: Well, it would be valuable if you went to the EPU and you want it stepped up by a factor of two. And then the next day you jumped. Then you'd say, ah-ha, something new has happened. It would be good for that point of view.

MR. DAVISON: Right. You go search it for what has changed.

DR. WALLIS: It's not likely to break, and if it does break, it won't break instantly, will it as soon as you go to the EPU?

MR. DAVISON: We thought it was an important part of the testing suite for a couple of reasons.

(1) we had to verify just straight up that

we did not exceed the design requirements, that we needed to be less than .3 percent.

(2) is we want to see how the actual steam, the moisture carry over responds as we increase power so we have the data of going up in power. And then it also provides the baseline data for continued weekly tests as we do on a normal basis to detect a change once we get to EPU and --

DR. WALLIS: A good check would be to go back to the old power level and see if it went up at that power level. You have some base to judge by. If you suspected anything, you could go back to your old --

MEMBER BONACA: But it's so low, the whole power level.

DR. WALLIS: But probably they could measure it that well.

MEMBER MAYNARD: But I agree with Graham. I think the real value is not so much in as it's going up is do you see a step change after some steady state operation. And that would indicate that something has changed, whether it be in the dryer or something else. But I think that's a good valid --

CHAIR ABDEL-KHALIK: Now what again are the action levels corresponding to the moisture carry over?

MR. DAVISON: I'll actually cover those on the slides. But for level 2 it's moisture carry over exceeding .1 or moisture carry over exceeding .1 and an increase by greater than 50 percent over the average three previous measurements.

DR. WALLIS: Ahhh.

MEMBER BONACA: So that takes into account your --

DR. WALLIS: So you have trouble getting to .1 by increasing by 50 percent over .0058 a few times.

MR. DAVISON: And to finish, the level one criteria is moisture carry over exceeding .3 percent. In that case we'd have to reduce back to power--

MEMBER SIEBER: Back to turbine flow?

MR. DAVISON: Correct.

MEMBER SIEBER: In fact, if you do have any concerns over the operation of the steam dryer you could still make these measurements because of your concerns that would happen to occur?

MR. DAVISON: Correct.

CHAIR ABDEL-KHALIK: Would it be helpful to tighten these action levels?

MR. DAVISON: The thing the fact that

we're starting off at such a low value and we're doing the hourly trend error -- the 2½ percent trending you see on the chart there these moisture carry overs done at every 1 percent power we'll be doing the analysis. I think the trend is valuable versus the absolute value.

The acceptance criteria itself is the no/go no when we do the analysis. Certainly if we see a trend that is surprising to us, we would be stopping and analyzing it regardless of what the absolute level 2 or level 1 criteria is. Of course, level 1 criteria is the design limit of .3, so --

MEMBER SIEBER: I would imagine taking moisture measurements at those close intervals, that the noise and air band for the actual measurement would exceed what one percent of increase in power would come up with. So you really can't too much out of these moisture -- if they deviate to a pretty large extent or they deviate without some identifiable cause like the power increase. I think those are valid.

CHAIR ABDEL-KHALIK: What is the error band in this measurement?

MR. DAVISON: That I don't know. An analysis, we can get that from our chemistry personnel. The question is what is the percentage of error or error band associated with --

CHAIR ABDEL-KHALIK: Right. I mean, is it a lot less than the 50 percent criterion that you're setting up for yourself.

MR. DAVISON: We'll provide that.

MEMBER BONACA: But moisture carry over is not the primary way of determining if something is happening.

MR. DAVISON: That is correct. That is correct. That's what the strain gauge and accelerometers are for.

The strain gauges for going back and looking at the loads on the dryer. The accelerometer is to see if there's some other phenomena happening to the piping system.

DR. WALLIS: So you measure moisture carry over by looking at the condensate and seeing how much of some chemical was transported all the way through the turbine --

MR. DAVISON: Correct.

DR. WALLIS: -- and the condenser, Okay.

MR. DAVISON: Condensate.

CHAIR ABDEL-KHALIK: Please continue.

MEMBER BONACA: But where is the sodium-24 coming from here?

MEMBER SIEBER: Where does it come from?

MEMBER BONACA: Yes. You're looking at sodium-24, right, you said?

MEMBER SIEBER: Injected probably around where the condensate --

MR. DAVISON: No, no. Naturally occurring this is not a tracer type test or injecting sodium-24.

MEMBER SIEBER: Right.

MR. DAVISON: Like you would do for a feedwater tank.

MEMBER BONACA: But where does it naturally occur or does it vary --

MEMBER SIEBER: In varies from location-to-location?

MEMBER BONACA: Yes. What is it associated with?

MR. DAVISON: We'll have to follow that up.

MEMBER BONACA: Yes. Well, if it's going to be some sort of a measure, however -- we need to understand a little bit about the errors and where it's coming from and what variability there could be. But presumably as it's an important measure, you want to have a good accurate measurement?

MR. DAVISON: Correct.

MEMBER BONACA: Okay.

MR. DAVISON: Most necessary and accurate for the turbine limitations as mentioned by we are using it as a predicting tool along with the other suite of assessments we'll be doing that are up here in the test matrix.

MEMBER SIEBER: You're doing it from a natural source, you have to take the ratio of what the raw water is versus what the condensation at the exit of the separator is.

MR. DAVISON: We'll have that as a follow up.

MEMBER BONACA: Thank you.

MR. DAVISON: You're welcome.

This is the chart that I spoke of yesterday. We did add it to show -- and the dark line at 111.5 and the CF, one is truncated there. The CF is with a correction factor applied for the cross flow system. That black line at 111.5 is where we'll be stopping with this cycle's testing. We just showed the continuation to a 115 percent to show what the testing would be when we pursued that. So the same suite of testing specifically around the dryer to see there's no changes.

MEMBER BONACA: Are you doing any tests

where you're closing off one of these four lines and increasing the velocity through the other lines to see what happens?

MR. DAVISON: No. We're not doing any abnormal alignment testing.

MEMBER BONACA: Is that information proprietary?

MR. DAVISON: No. The next slide I have-- well, we'll show it in the closed session. But the next slide is --

DR. WALLIS: Well, just to repeat what we all know is that you're only monitoring the steam lines. You don't have any strain gauges in the dryer itself?

MR. DAVISON: That's correct. There's not a monitoring package installed on our dryer.

MEMBER BONACA: And these are accelerometers and strain gauges; you've got both of those?

MR. DAVISON: That's correct.

MEMBER BONACA: And the same locations or different locations?

MR. DAVISON: Same piping systems. The strain gauges were shown at the two locations. There are accelerometers throughout the main steamline.

MR. PIERCE: Is it impossible to put instrumentation inside the steam dome, or is that just something that's prohibited by the heat and environment?

MR. DAVISON: It is not impossible. In fact, new dryer installations require monitoring. In fact, Susquehanna will have a monitored dryer. Quad Cities had a monitored dryer. However, instrumenting an irradiated dryer becomes very dose intensive as well as cost prohibitive as well. But that is the primary reason why an irradiated dryer is not instruments. But it is physically possible.

MR. PIERCE: You say an irradiated dryer. You mean it's not protected from radiation or you mean--

MR. DAVISON: The fact that it's been in the vessel for 20 plus years.

MR. PIERCE: Oh, been in the vessel for a long time? Okay. All right.

MR. DAVISON: Yes. So even to work on it when we do inspections or if we were to have to do repairs when it's in the dryer pit out of the vessel, it still does --

DR. WALLIS: I would think if a dryer were shaking badly, it would actually ring the vessel.

You'd detect something through the vessel itself if there -- I don't know how bad this thing shakes. But it's a pretty massive thing. And if it's actually shaking quite a bit, that metal is in contact with the vessel. It's supported by --

MR. DAVISON: The dryer itself isn't shaking. You know, we talked about the leveling that we did. And, of course, it's the plant --

DR. WALLIS: But a piece of it is shaking?

MR. DAVISON: You've got pieces of it. That the errors that we've seen in the industry are pieces of the dryer essentially pealing off, if you will, versus the whole 80,000 pound dryer itself.

DR. WALLIS: I know. But that piece shaking does get transmitted. So there's nothing detectable from outside when there's a problem with the dryer?

MR. DAVISON: Other than what we're monitoring, no. Specifically moisture carry over as well as the actual strain gauge data we'll be taking.

MEMBER MAYNARD: Do you have any loose parts monitoring system in the vessel?

MR. DAVISON: No, we do not.

CHAIR ABDEL-KHALIK: Okay. Is this the end of your open session presentation, Mr. Davison?

MR. DAVISON: I can skip the next slide. Two slides up. All the next three slides were to show representation of -- the one that you're not seeing because it's proprietary, was just the PSD to frequency curve with a baseline where we're at and our level 1 and level 2 criteria where we would be predicting. That's how we're going to do that. We'll talk more about the actual analysis piece in the closed session. But it was literally just a curve. And that's how we will be communicating to operations information that will be provided to the NRC.

We have curves PSD versus frequency for each of the four steamlines. Every data point we take we'll be putting it on there to make sure we haven't exceeded a level 1 or level 2 criteria.

MEMBER BONACA: What is FIV?

MR. DAVISON: The next one that I can show, the flow induced vibration measuring, you see here this is just an example of one sheet of level 1 criteria for the main steamlines and it also includes some of the feedwater lines in the drywell.

Where we have our accelerometers, what our current acceptance criteria values are and then how we'll be recording them and showing them as percentages. Eighty percent or less, good; exceed that you're in a level 2 criteria, you exceed the level 1 criteria we're going to stop --

MEMBER BONACA: What is Xg, Yg, Zg and all these?

MR. DAVISON: That's just at the first location the main steam 26 inch pipe vertical rise elevation 154 in the drywell. IT has an X, a Y and a Z component.

MEMBER BONACA: So it's the measurement?

MR. DAVISON: Correct. You know acceleration in the X,Y and Z plane. And the g is that we're measuring it in gs.

And you can see some of the locations that when we worked with structural integrity did not require an accelerometer in that direction, piping configuration or support something else.

MEMBER BONACA: So .584 means .584 g?

MR. DAVISON: Correct. For that --

MEMBER BONACA: Acceleration?

MR. DAVISON: Correct. That location -- in the X direction at that location in the main steamline.

CHAIR ABDEL-KHALIK: Dr. Davison, rather than jumping back and forth between open and closed. In order to provide a coherent presentation, perhaps you can include this in your closed session presentation?

MR. DAVISON: Yes, I can do that.

CHAIR ABDEL-KHALIK: Okay. At this time we'll hear from the staff, again in an open session. And then we'll have a closed session where both the applicant and the staff will make additional presentations on this material.

MR. DUKE: Mr. Chairman, could we get some clarification as to what information regarding the Susquehanna replacement dryer desired so that GE could look at whether that information is available and whether it can be shared with the Committee.

CHAIR ABDEL-KHALIK: You make specific changes to thicknesses --

MR. DUKE: Yes. There was a question as to how our dryer compares to the Susquehanna replacement dryer and GE's looking for a little more detail as to what type of information is being requested?

CHAIR ABDEL-KHALIK: The thicknesses of the plate that were changed from, for example, an eighth of an inch to a half of inch, were these the same changes that were made in the Susquehanna dryer.

MR. DUKE: Thank you.

CHAIR ABDEL-KHALIK: Please refer to the

nonproprietary staff presentation at this time.

Proceed.

MR. MANOLY: Good morning. I'm Kamal Manoly the Advanced Chief of the Chemical and -- with the Division of Engineering, NRR. And I'm presenting first the team of the staff and the contractors who supported us in the reviews of the Hope Creek dryer and other mechanical components.

The review started with Tom Scarbrough and Dr. John Wu. And John and Tom moved to NRO, but they're still supporting us. Currently we have Dr. Chakrapani that's on my staff and also supported by three contractors, Argonne National Lab Dr. Vikram Shah and Dr. Ziada is the other and Dr. Steve Hambric from Penn State.

I guess we'll start with the amount of gradation of the application.

Tom Scarbrough will go through the nondryer portion first. And then we'll follow that with the dryer portion.

MR. SCARBROUGH: Good morning. I'm Tom Scarbrough.

Just again to give you an overview of our evaluation areas --

MEMBER BONACA: Tom, where are you now?

You have moved?

MR. SCARBROUGH: Yes. I'm in the Office of New Reactors now.

MEMBER BONACA: I see. Did SSES drive you out of this or what?

MR. SCARBROUGH: No. Actually, it's one of the more enjoyable engineering areas --

MR. LAMB: We tried to keep him.

MR. SCARBROUGH: So these are the areas that we reviewed, the pipe rupture locations and dynamic effect, pressure-retaining components and supports, the nuclear steam supply system, piping components and supports, balance of plant, reactor vessel and supports, control rod drive mechanism, recirculation pumps and supports, reactor pressure vessel internals and core supports, safety-related valves and pumps, seismic and dynamic qualification of equipment and potential adverse flow effects which we'll talk a bit about this morning.

So those are the broad areas that we look at.

In terms of the scope of the review, we look at the methodology applied and the loads that will result from the constant pressure power uprate, the resulting stresses and cumulative fatigue usage factors, the acceptance criteria, the applicable code editions and addenda, nd the impact on functionality of safety-related pumps and valves and the piping over pressurization analysis for the proposed EPU.

We also look at the acoustic and flow-induced vibration loading and monitoring to provide confidence of the structural integrity of the plant components.

DR. WALLIS: Did you do any confirmatory analysis?

MR. SCARBROUGH: No.

DR. WALLIS: Did you do any for the other plants with EPUs?

MR. SCARBROUGH: No, we didn't.

MR. MANOLY: At Vermont and Susquehanna. And the work on Quads was really after the license was granted. So we're really following the operational failures and then the fixes that took place after that. But in all of that we did not do confirmatory analysis.

We reviewed the licensee's work in great detail, and that's why we're using the Argonne and the professors from Penn State and McMaster for that purpose.

MEMBER BONACA: Maybe I shouldn't say this is an open session, but did you discover some errors in the previous analyses?

MR. MANOLY: What do you mean by "previous"? Which ones?

MEMBER BONACA: Of any of the other plants?

MR. MANOLY: Well, you know, engineering is -- people who have done design sometimes disagree on certain parameters. But I wouldn't call that errors in the sense that something was missed completely. But sometimes we disagree on certain parameters and we discuss it with the applicant and we reach an agreement.

MEMBER BONACA: How large were these disagreements?

MR. MANOLY: It depends on the variables. I mean, there are a lot of the -- as you go through the slides in the SE, there was a lot of -- these parameters were discussed and negotiated. And it's a new area that we're getting into that was not something that didn't -- you know, looked at the past and like other structures which the science or the state-of-the-art is pretty much stabilized.

MEMBER BONACA: Okay. We need to follow this up. I want to understand clearly what you found in the past in terms of problems.

MR. MANOLY: Okay.

MR. SCARBROUGH: This is still an overview. Coolant pressure boundary and balance-of-plant piping systems were evaluated for EPU.

The main steam and feedwater piping and supports were evaluated because of the higher loads and flows, the 24 percent or so increase in flow rates for main steam and feedwater, which increased some of the break flow rates. And there was evaluation of the loads was looking for that.

Other piping would be less affected by the EPU conditions.

The results that were calculated where the stresses were less than the applicable ASME Section III and the ANSI B31.1 code allowable rates.

MR. PIERCE: You say you calculated stress. What was the conditions by which you calculated? Did you do your calculations or you reporting on your assessment calculations done by the USSIE.

MR. SCARBROUGH: The licensing did the calculations and then we review the calculations and look for changes for how they did the calculations.

MR. PIERCE: Okay. So it was not clear

from the statement as to who did the calculations. Okay. Thank you.

MEMBER BONACA: But the stresses, of course, depend very much on the loads. And so we have to discuss how these loads were calculated.

MR. MANOLY: Yes.

MEMBER BONACA: But there are two parts of this. One is the loads and the second part, of course, is the finite element analysis. Both are subject to some level of scrutiny. And if you'll go into details of how these loads were --

DR. SHAH: We will do that in the proprietary portion of presentation.

MEMBER BONACA: And why we should believe these loads?

DR. SHAH: Yes. We did quite a --

MEMBER BONACA: Okay.

MR. MANOLY: Tom's still discussing the nondryer portion here.

MEMBER BONACA: Oh, okay. All right. WE see the top. Okay.

MR. MANOLY: This is partly the analysis where the exceed limits are being evaluated.

MEMBER BONACA: Okay. You are going to come to the dryer?

MR. SCARBROUGH: Yes, we are. We are just giving the other areas that we reviewed first.

In terms of the evaluation of the safety-related pumps and valves, we looked at the pumps and valves that was within the scope of ASME code. We focused on the EPU affects for the functional performance of the pumps and valves and acceptance criteria related to the general design criteria and 50.55(a). And how we did this we looked at the review of what was changing from the EPU conditions, how would that effect the pumps and valves. We asked for examples to look and see how they addressed Generic Letter 8910, NOV promoted off the valve program and any changes to those types of programs and what parameters were being adjusted as a result of the EPU.

So we did that review and we found roughly minor changes to the parameters that would affect this equipment. So we didn't have any concerns with the pumps and valves area, which was my area of the review.

And now we're getting to the potential adverse flow effects.

And the areas that we're going to talk about are: The steam dryer function; the dryer modifications; the dryer review. And those two specific areas we'll be talking about in detail during the closed session. And then the monitoring and the power ascension test plan and the license conditions. So we'll cover those in this open session.

MEMBER BONACA: But isn't the monitoring and power ascension going to depend somewhat on the stuff in the closed sessions?

MR. SCARBROUGH: Right, there will be. But in terms of the license conditions, that's open.

MEMBER BONACA: Yes, of course.

MR. SCARBROUGH: We can talk about that in open.

MEMBER BONACA: All right. But the reasons behind the license conditions we revisit that?

MR. SCARBROUGH: Yes.

MEMBER BONACA: Okay.

CHAIR ABDEL-KHALIK: We will revisit the plant monitoring --

MEMBER BONACA: Right.

CHAIR ABDEL-KHALIK: -- and instrumentation, et cetera later on --

MEMBER BONACA: And the power ascension?

CHAIR ABDEL-KHALIK: -- after in addition to whatever you'll present in the open session. We will revisit that later on, after lunch, perhaps?

MR. SCARBROUGH: Sure. Absolutely.

In terms of the steam dryer function itself, it's function is to remove moisture from the steam prior to exiting the reactor pressure vessel moving into the main steam lines and then to the turbine generator. That's where those limits that you were talking about a few minutes ago came from.

There's no specific safety function for the dryer. Its function is to remove that moisture, but it must retain its structural integrity to avoid a generation of loose parts that might adversely impact the capability to other equipment to perform their safety functions. So we're focused here in our review as part of the structural integrity.

MR. MANOLY: I would just add that in terms of structural integrity, it could potentially have cracks but it doesn't result in loose parts, they're okay. It's really the point here is that you try to avoid the generation of loose parts. It's a different threshold then you would expect for other structures. That's what I would like to highlight.

DR. WALLIS: But this no safety function always puzzles me. I mean, it's obviously not designed in order to improve safety. But in the event of a pipe break in which there is flow through the steam dryer, it's going to effect what happens. So even if it's not designed to have a safety function, what happens in an event is going to be -- it's like an automobile. I mean, there are breaks and air bags and all kinds of things. But there are other things which don't have any obvious safety function which will affect what happens in an accident. And somehow or other because they're not specifically designed with a safety function, they're said to be unimportant.

MR. MANOLY: Most of the discussion here really is focusing on the operational loads. Now that also designs for main steamline break. But the design loading is not as destructive as operational load. So they're full --

DR. WALLIS: I'm just saying the idea that it has no safety function doesn't mean to say that it doesn't have any influence on what happens during an accident. That's just what bothers me, that you sort of dismiss it as having no safety function so we don't need to think about it in terms of safety.

There can be accidents where it might have some influence on what happens. That's the only thing that troubles me.

MR. MANOLY: Well, as long as it does not break into pieces that would get hammed in MSIVs --

DR. WALLIS: There's no way it can influence the course of accident?

MR. MANOLY: I don't believe so. But someone may question that. But I don't believe -- because you're designing to the main steamline break. That's the design basis for the dryer. But that's not the governing load in terms of dryer failure is --

DR. WALLIS: The main steamline break, presumably, anything coming out of the core has to go to the steam dryer to get to the steamline. So it's going to have some affect on what happens.

MEMBER BANERJEE: But it can retain its structural configuration.

DR. WALLIS: Except during the accident, right?

MEMBER BONACA: Are the loads much lower than during normal operation?

MR. MANOLY: Because you have just to one type loading, whereas during operation you have that cycling that's going on.

MEMBER BONACA: Well, imagine that -- well, I don't say imagine. But imagine that the dryer was cracked and then you quite a high load which wasn't a vibrational load, but it could lead to vibrations as well because of vortex shedding or whatever and the dryer fell apart at that point. Is there a safety concern associated with that?

MR. MANOLY: There probably would be, yes. I mean, if it's cracked in a way that degraded the cross section so much -- yes, I would agree with you.

MEMBER BONACA: Or some part broke off or something.

MR. PIERCE: Can I ask a question? Has the present steam dryer, have you ever taken the thing apart and looked at it to see if it had any cracks or has it never been examined for cracks so far?

MR. MANOLY: Well, I think in the presentation they modified dryer.

MR. SCARBROUGH: And they had to form baseline inspections following the BWR --

MR. PIERCE: It does include a modified or they're about to modify it?

MEMBER BONACA: They modified 20 years ago.

MR. SCARBROUGH: Before they even started the plant up. Before they started the plant up the very first time 20 years ago they put in these modifications to strengthen its structural integrity.

MR. PIERCE: But since it's been running all these years, have they actually pulled it apart and looked and it to see if there are any cracks?

MR. SCARBROUGH: No. They perform inspections on it per the BWR Owners' Group guidance in the past.

MR. PIERCE: But that's external?

DR. SHAH: They took it out.

MR. PIERCE: Oh, they did take it out? Okay.

DR. SHAH: During the refueling. And then they can inspect it.

MR. PIERCE: Because when I read a newspaper, I read for instance in Vermont the results are the stuff about cracks in the Vermont Yankee.

DR. SHAH: You're right. That's correct. Vermont has some IGSC cracks.

MR. PIERCE: Yes. Yes.

DR. SHAH: But after the first cycle of operation. And they didn't believe that it has nothing to do with fatigue cracking.

MR. PIERCE: Right.

DR. SHAH: And they left them in place. Now they will examine them again in next outage to see if there is any increase.

MR. SCARBROUGH: And those conditions that we proposed for Hope Creek as well where they do those inspections --

MR. PIERCE: Yes. Right.

MR. SCARBROUGH: -- for several outages to look for any --

MEMBER BONACA: Now these are visual inspections, of course, right?

MR. MANOLY: Yes, yes.

MEMBER BONACA: And can they see all the important parts of this dryer with these visual inspections.

MR. SCARBROUGH: The ones that are available from their inspection from looking at the outside. There's guidance in the BWRVIP-139 document which gives them guidance on where to look for welds that may show cracks on that outer hood, which is the place where we have the most interest because that's where the loose parts would really come from. So they look at that very closely in terms of looking at the welds and seeing to look for any cracks that might appear in that. So that's they have --

DR. WALLIS: Can I go back to my point?

I'm told we have about mach .1 in a steamline, right? Mach .1 is what I'm told. I think I read.

MEMBER BANERJEE: No. It's 160 feet per

second.

DR. WALLIS: I was told Mach -- it's Mach .10 something or other.

MEMBER BONACA: Three hundred meters per second is --

DR. WALLIS: So it's .1 Mach. Now the steamline breaks, right, you could choke flow in the steamline, presumably, at Mach 1. So you've got ten times the velocity. Doesn't that do something to the dryer?

MR. SCARBROUGH: Those are analyzed. The loads -- those loads are analyzed as part of --

DR. WALLIS: So the dryer draws okay with that sort of sudden increase in velocity?

MR. SCARBROUGH: Right. Those are analyzed--

DR. WALLIS: The load must increase by an enormous amount of what it does, the normal operation. Again, that's analyzed?

MR. SCARBROUGH: That's analyzed.

MEMBER BONACA: Does load go as the linear part of the velocity or the square of the velocity?

DR. SHAH: Square velocity.

MEMBER BONACA: You go with the square, the speed of sound roughly is, let's say, a factor of five. So you've got a load which is a factor of 25 more.

DR. WALLIS: Yes, it's bigger than that.

MEMBER BONACA: Or maybe it's a factor of ten. I don't know, whatever.

MEMBER SIEBER: The question is did the applicant or the staff make a calculation at main steamline break flows to determine if the dryer would fail. Now if you would tell yes or no, I think that would --

MR. MANOLY: The dryer is evaluated for the main steamline break. All dryers are. Actually, that's what we looked at at Quad Cities and focused on and then realized that that was not the governing load.

DR. WALLIS: Thank you. That's good.

MEMBER SIEBER: And the dryer has to withstand that until the main steam isolation valves close, right.

MEMBER BONACA: I guess the issue is if it has been tracked previously whether it would break up. Because the intact valve, presumably, holds up to the loads that you're talking about. But then if there are fatigue cracks, what happens at that point?

MR. SCARBROUGH: Well, that's part of

evaluating to make sure that the loads for these increasing resonance potential is less than the fatigue cracking limit. So that's part of the evaluation to make sure it's below that. So that's our goal.

MR. MANOLY: With margin.

MR. SCARBROUGH: With margin.

DR. WALLIS: Right.

MR. HYLAND: My name is Pat Hyland. I'm the Director of Engineering in NRR.

And I just want to clarify the question, if I could, or at least our answer to it.

Clearly the dryer has a safety function, just as the staircase I walk up every day has a safety function not to fall.

You're correct that just a flat statement no safety function is misleading. What that means is no safety function as applied under the Appendix B 10 CFT quality assurance 18 criteria.

There's no credit, I believe, taken for the dryer as far as the analysis is to the pipe failure what happens to the public, what's released. You can calculate credit for scrubbing, but there's no credit taken in the analysis.

Clearly it's important. Every piece of

equipment in the plant is equipment important, especially those staircases I walk up. So it is important to safety.

DR. WALLIS: Thank you.

MR. SCARBROUGH: Okay. In terms of the steam dryer modifications, you've heard some about them a few minutes ago. But it is curved hood design. They did perform modifications and we have a slide for that for the closed session. And there's been no significant performance issues for the dryer for the 20 years of operation that its seen.

The broad picture of the steam dryer review and findings. The contract assistance that we've mentioned, we evaluated the steam dryer analysis through numerous information requests and meetings.

There was an audit of this team at the CDI office in May of last year.

The conclusion is that there is reasonable assurance that the Hope Creek steam dryer is within structural limits for current license thermal power and up to the extrapolated EPU conditions. And we consider the dryer analysis to be acceptable for EPU.

And this is just an overview of what we'll talk about in details.

MR. PIERCE: Can I ask you what does

"audit" mean?

MR. SCARBROUGH: Oh. This team went to the CDI office in New Jersey.

MR. PIERCE: Yes.

MR. SCARBROUGH: And reviewed their analyses and had discussions with their contractors in detail of their evaluation of the dryer and observed their scale model testing facility, discussed that operation with them. And so that's the type of quality that where we actually go to either the plant itself or a contractor office and look through the calculations and information or detail.

MEMBER BONACA: And these calculations are often done with things like computer codes and so on?

MR. SCARBROUGH: Right.

MEMBER BONACA: So do you also audit the computer codes?

MR. SCARBROUGH: There was discussions with the gentleman who ran the computer codes there, members of the team reviewed with that and observed how they set up their computer mathematical analysis and discussed that with them. So that was part of the audit as well.

MEMBER BONACA: And so there was some sort of due diligence done about these codes?

MR. SCARBROUGH: Yes.

MR. MANOLY: Yes.

MEMBER BONACA: And the models in them?

DR. SHAH: We reviewed the models.

MEMBER BONACA: And the applicability. But are these approved codes or what are they?

MR. SCARBROUGH: No. They're codes that are specific to the CDI contractor. So they're specific. They aren't codes that have been submitted as a topical code, a topical report code that we've done reviews for. These are plant specific codes where an individual utility will use them. And we use them or I weight them for the plant-specific basis. They aren't like generically approved codes.

DR. SHAH: I think for analysis they use the AXIS code --

MEMBER BONACA: But AXIS is not been approved, has it? It's accepted.

MR. MANOLY: When you say "approved," the NRC we go to the approved -- we do some confirmatory comparisons and benchmarking. And AXIS is being widely used to compare to other codes. And we don't --

MEMBER BONACA: Well, this is a rather larger issue --

MR. MANOLY: Yes.

MEMBER BONACA: -- which I don't need to take up here. But there is an issue of using commercial codes in this way without actually having the source code and looking at it carefully and being sure.

I mean, the other stuff is pretty circumstantial. So if you use a CFD code like FLUENT or something, for indicative purposes it's okay. But you haven't actually delved into the code in the same detail as when you approved a code such as submitted by a vendor or something where you go into it great detail for that.

MR. MANOLY: Yes. There are two codes here that I guess Tom was referring to. Once is the acoustic circuit model analysis code, and that's a proprietary code that CDI had developed. And the other one is after the loads are developed it is applied on the dryer, they use ANSIS. And we are much more knowledgeable about ANIS than the acoustic circuit model code, which we have looked at --

MEMBER BONACA: But there is an issue of transparency related to some of these codes like ANSI or FLUENT or whatever. And these codes are not available in source code, at least I don't know if ANSI is to you, but some of the other codes are not.

And they're being used based on sort of circumstantial evidence that they work in chemical applications or something where our standards of looking into them are much different from what is required for a nuclear plant, you know, in terms of the validation of the result of quality assurance about the results.

MR. MANOLY: I believe that we had looked at benchmarking of various codes. And sometimes we reviewed Brookhaven National Lab to benchmark some codes that are coming up recently. But I don't believe we have a problem with ANSIS. I mean I've never -- I've been with this branch for a long time, and there was never an issue that came that the results using different codes have invalidated the answers.

Now misapplication of the codes can give you erroneous results, and we all know that. I mean, when you're doing time history analysis you can get any answers you want depending on the steps, you know, delay. But whether the code has flaws in it, that's a different --

MEMBER BONACA: All these codes have flaws in them.

CHAIR ABDEL-KHALIK: Let's continue with the presentation, please.

DR. WALLIS: Well, I was wondering if we

couldn't follow this up a little bit just to be clear to the public. I mean this audit, you looked at -- the ANSIS code is part of it, right, if you looked at it? You accept that as for the mechanical part. But there's CDI analysis, which is particular to this plant, it's not part of some standard procedure which is a code. And so you have to accept. And it's been said it's an open session. Your audit has to satisfy you that what CDI developed is a special analysis for this plant was adequate?

MR. SCARBROUGH: Right. And we can talk about that in the closed session.

DR. WALLIS: When you put it in this open session as an audit, it wasn't as if you were just looking at the use of a standard code. You were looking at a specific analysis for this plant?

MR. SCARBROUGH: Exactly. Yes, sir.

MR. PIERCE: Can I make one comment or question?

In your request for additional information I know at least on one occasion you asked the licensee to increase or to reduce the mesh size or refine the mesh.

MR. SCARBROUGH: Yes.

MR. PIERCE: And apparently you do worry

about such things when you do your analysis or things that you're wondering whether or not they have used ANSIS correctly.

DR. SHAH: We have done, at least the things we'll talk in the closed -- proprietary session. We have underscored them more than that.

MR. PIERCE: Yes.

MR. SCARBROUGH: Moving on to the plant monitoring part, you know the licensee evaluated what systems would be potentially susceptible in the installed accelerometers and such in places where those systems could be susceptible. There's acceptance criteria that's part of the power ascension program. They're using the ASME standard in Guide Part 3 for the methodology for vibration.

They did install vibration accelerometers back in 2004 and gathered baseline data to look for any potential resonances, and did not see any.

As part of the monitoring they will be performing visual walkdowns.

And as I mentioned, they did install accelerometers on the safety relief valve pilot valve assemblies to look for potential vibration for those components.

And they performed some modifications to reduce the susceptibility to piping vibration as part of that.

DR. WALLIS: Could you tell me, we saw -- are we going to talk about that page we saw which was flashed up there with the acceptance criteria, or we're not allowed to talk about that? Can we talk about that?

I think I saw things like half a g or something up there, maybe 1 g. An order of magnitude of a g. Could you give me some idea of what a pipe is like when it's oscillating with 1 g? Is it like a washing machine shaking or is it like a train going by, or is like a thunderstorm? Or what is it like when a big pipe oscillates at 1 g?

MR. MANOLY: It's oscillation for size --

DR. WALLIS: Yes, what's it like? If you're standing there and a steam pipe is oscillating with 1 g? What's it like? Is the world shaking if you're near it, or is it just a slight vibration? What's it like?

MR. MANOLY: Well, it depends on how's it supported. I mean, if you have --

DR. WALLIS: Tell me how it's supported.

MR. MANOLY: If you have large spans, it is different than if you have very short spans.

DR. WALLIS: So there's no way you can put it into human terms that I can understand?

MR. MANOLY: Well, I mean big -- if the spans are very large. For service water piping where it's the nonsafety part when you have huge piping with -- but you don't see really 1 g at the service water piping. So --

DR. WALLIS: But you can't put it in some way which I can visualize? I mean, I have no idea what 1 g is like when a pipe shakes.

MEMBER BONACA: Is it like a small earthquake, a large earthquake, or a medium size earthquake?

DR. WALLIS: What is it?

DR, HAMBRIC: This is Steve Hambric from Penn State.

It all depends on the frequency of the vibration.

DR. WALLIS: Okay. Well, we know what the frequencies are in this case.

DR, HAMBRIC: Well, it depends.

MEMBER BONACA: You have 15 Hertz or 160 Hertz we've been told in rough terms.

DR, HAMBRIC: So divide by 2 pi 15 squared and that give you one displacement. Divide by 2 pi

150 square, it'll give you much smaller displacement.

MEMBER BONACA: Well, let's take the 15.

DR, HAMBRIC: Okay. I'm trying to do the math in my head. You're talking about roughly a 1,000 -- 9.81 meters per second squared divided by 1,000. So -- well, it's not huge. It's small. You're not doing this.

DR. WALLIS: Okay. So it's a very large vibration. And so visually if I were there, I would know that it was oscillating?

DR, HAMBRIC: Right. But you wouldn't be backing away.

DR. WALLIS: I wouldn't be backing away. Okay.

MR. MANOLY: Safety-related piping in the plant usually between 10 or 15 Hertz.

DR. WALLIS: That's helpful.

MR. MANOLY: That's typical.

MEMBER SIEBER: Compared to everything else in the plant, you probably wouldn't --

DR. WALLIS: Right. All the other noises going on, you wouldn't notice?

MEMBER SIEBER: That's right.

MEMBER BONACA: Now the question arises how good of indicator is this of what's going on the dryer then?

CHAIR ABDEL-KHALIK: We'll get to that.

DR, HAMBRIC: Well the acceleration to measure the strains or measure the strains around the group of the --

MEMBER BONACA: We realize that, but the accelerometers are also used as backup we are told. We're also measuring the accelerations.

MR. SCARBROUGH: Right, that's one of the plant monitoring --

MEMBER BONACA: We're just asking.

MR. MANOLY: For monitoring also for piping, we use the OM standard for displacement, amplitudes. I guess the question is for piping or for other components. You know, you have the OM standard, that's the industry standard for verification of the amplitudes that you don't exceed the OM limits.

CHAIR ABDEL-KHALIK: Okay.

MR. SCARBROUGH: If we move to the power ascension test plan. The established criteria, as you heard this morning there's two levels. There's the level 1, which is a power reduction, if they hit that level. And then a level 2 which is a power hold. And we'll have some more details on that during the closed session.

There's EPU startup test procedure and there's a license division which goes through the contents of that test procedure in terms of the limit curves, the hold points, the parameters, the inspections and walkdowns and actions that you take.

And if you have acoustic signals that challenge those limit curves, there's methodologies for updating the limit curves themselves. And the test plan will include detail monitoring analysis.

And then over the longer term there's steam dryer inspection requirements. And those will follow the BWRVIP-139 document.

MEMBER BONACA: Are you going to deal with this in more detail, Tom, when it comes to the closed session or --

MR. SCARBROUGH: Well, actually, I have some information here which will kind of go through most of the license conditions which kind of lays out what the power ascension test plan is.

MEMBER BONACA: The broad question I have before you even get into this is when we had plants, we've had similar curved hood designs and so on, with lower velocities and instrumented dryers. We wanted to have a power ascension plan which actually closed off things like one of the steam lines in order to get power velocities in the other lines. And we had a very, very systematic way of raising power very slowly using that as a pilot. Okay. And we were trying to relate what was happening in the dryer to what was happening in the lines, and so on. And we had that sort of measurement.

And on that basis we approved the power ascensions plans and so.

Now with this dryer, which is not instrumented which is an old dryer which maybe have a curved hood which has higher velocities, we are not putting this type of power ascension plan together where we monitor what's going on in three lines rather than by closing the fourth so we have that effect of the higher velocity in advance of actually doing it. So you are going to explain the rational while why we do this for one of our plants and why we don't -- which is better instrumented with a new dryer and we're not going to do it for this?

MR. SCARBROUGH: Right. We probably should talk about that in the closed session.

MEMBER BONACA: Okay.

MR. SCARBROUGH: Because we do have information that we can talk about that.

MEMBER BONACA: All right.

MR. SCARBROUGH: Yes. When you see the power ascension test plan through the license condition, there's not that closure of an MSIV that's shift of steam.

MEMBER BONACA: Right.

MR. SCARBROUGH: That's not part of it. So --

MEMBER BONACA: No. This is a very different power ascension plan than we've approved previously, in the previous approval.

MR. SCARBROUGH: Well, it's very similar to Vermont Yankee's. And except for that portion with the MSIV closure that Susquehanna is doing, it's similar. But they don't have that portion in it.

MEMBER BONACA: And they don't have the instrumentation that Susquehanna has?

MR. SCARBROUGH: On its dryer filtering.

MR. PIERCE: I have a question. Now as I understand, they have a backup spare dryer. And the reason as stated before by Davison that they didn't want to instrument the present dryer because it's heavily radiated. Has the question ever gotten up as to why they used their spare dryer and it isn't radiated at all.

MR. SCARBROUGH: There were discussions.

That's probably something more for asking the licensee.

MR. DAVISON: Yes. This is Paul Davison.

MR. PIERCE: Yes, Paul?

MR. DAVISON: That dryer has been sitting out unprotected near the Delaware Bay for those many years. So it is not suitable for placement into the vessel.

MEMBER MAYNARD: Also, I'm not sure it would give any meaningful data. Because as I understand it, you said that had not been modified. So it would be a totally different structural --

MR. PIERCE: Well, presumably the modification is not as big a deal as making a new one.

MEMBER SIEBER: It's an inferior structure.

CHAIR ABDEL-KHALIK: Well, let's focus on the presentation, please.

MR. PIERCE: Okay.

MR. SCARBROUGH: So let's go through the--

MEMBER BONACA: And you will deal with that question?

MR. SCARBROUGH: Yes, we will. We can talk about that during the closed session.

MEMBER BONACA: Okay.

MR. SCARBROUGH: In terms of the development of license conditions, this is a similar approach that we've done for Vermont Yankee and Susquehanna. There's a slow deliberate power ascension, there's hold points and there's data evaluation along the way looking for trends and such.

The startup test procedure formalizes the plan for the steam dryer and the plant instrumentation and all the activities associated with that startup test procedure.

There's a license condition number 3, which we'll show in a minute, which specifies the startup test procedure contents.

And then the license conditions provide for licensee and NRC interaction to address plant data, evaluations, walkdowns, inspections and startup procedures. Similar to what we've done for the other plants as well.

Okay. So in the next series of slides I'll try to give a very overview of the license conditions. They're spelled out in more easily readable form in the SE itself, but to try to summarize it in here.

License condition number one provides the overall sort of monitoring that's done during the startup power ascension. There's monitoring of the main steamline strain gauges hourly. There's a hold at each five percent step for 96 hours, and that's done to evaluate plant data, look for trends, conduct walkdowns and then provide that evaluation to the NRC Project Manager.

If a level 1 main steamline limit curve --

DR. WALLIS: Now could you tell me what you understand by "conduct walkdowns." This is a very general term.

MR. SCARBROUGH: Well, they walk through the plant and they look for all the areas that are available, accessible during plant operation. And they look for anything --

DR. WALLIS: So they listen and see if anything's moving on --

MR. SCARBROUGH: They look for things for any small breaks. You know, at Quad Cities they had some small drain lines break, things of that nature.

DR. WALLIS: Yes.

MR. SCARBROUGH: They look through -- they see what vibration there is. They listen for any sounds. Because, you know, we've had that happen before where you could hear the whistling. So they do that sort of thing.

And then if they see any places that they need to do any hand held accelerometers, they can do that as well. So that's the type of thing we expect them.

And then we discussed that with them during that hold period to see what they found. And they usually will have the engineers who were out doing the walkdowns talk to us on the phone about what they saw.

DR. WALLIS: Okay.

MEMBER MAYNARD: Will operators also be part of these walkdowns? Because an experienced operator can tell if there's a difference --

MR. DAVISON: Yes. This is Paul Davison.

Equipment operators who are used to doing the rounds will be part of the walkdown teams.

MR. SCARBROUGH: Then there's monitoring of the reactor pressure vessel water level instrumentation and main steamline accelerometers looking for resonances. This is what we talked about earlier in terms of if you see resonances that are starting to increase above normal levels, this is where you start to see an issue before it hits one of the limit curves. But if you start to see that there's resonance starting to occur, you stop the power ascension, you evaluate structural integrity of the dryer and then provide the results to NRC.

DR. WALLIS: How do you know resonance has occurred?

MR. SCARBROUGH: As you're monitoring the instrumentation in the accelerometers and also through the strain gauges if you start to see through the data a resonance start to occur --

DR. WALLIS: It's the A frequency growing much more than the other ones?

MR. SCARBROUGH: Yes.

MEMBER BONACA: So the data is being recorded somewhere?

MR. SCARBROUGH: Yes.

MEMBER BONACA: And you're taking probably the density functions or something to look for peaks.

MR. SCARBROUGH: Right.

MEMBER BONACA: So you have that in addition to these walkdowns?

MR. SCARBROUGH: Right. Right. It's a combination of a lot of efforts to look for any adverse flow effects that may be occurring.

And then the last bullet there has the NRC approval. Now we have modified this somewhat since we did the slides. There's a license condition number 4, which I'll show you, which talks about if you change the level 1 performance criteria. And if you change that, the NRC approval has to be obtained. So we've adjusted this license condition to match Susquehanna's, which moved that process from obtaining NRC approval under license condition number four. So I'll show that to you in just a minute.

MEMBER ARMIJO: Has NRC reviewed and approved these existing limit curves?

MR. SCARBROUGH: The limit curves that we received, yes. We've seen them and they were part of the review as part of the safety evaluation preparation.

MEMBER ARMIJO: Right.

DR. WALLIS: How do you expect them to do the second bullet up from the bottom, "evaluate structural integrity of dryer?" How do you expect them to do that? They can't get in there, there's no monitoring in there.

MR. SCARBROUGH: Well, they can rerun the analysis and look for stresses on the dryer.

DR. WALLIS: They can redo the analysis, but they can't actually inspect the dryer itself?

MR. MANOLY: No, no. That's not visual. No, that's not visual.

MR. SCARBROUGH: No. That's in terms of mean evaluate it through the --

MEMBER BONACA: They can only do this through some model because they have no direct measurement in that dryer.

MEMBER BANERJEE: Whereas, previously the condition you put is if the ratio between -- I forget what it was -- 2.71 or something, the stress intensification factor.

MR. SCARBROUGH: Right.

MEMBER BANERJEE: That was a limitation you could directly put because you could measure the stresses in the dryer, right?

MR. SCARBROUGH: Well, they're not measuring the stresses in the dryer. They're taking--

MEMBER BANERJEE: I know what they are doing here. This is different.

MR. SCARBROUGH: Right.

MEMBER BANERJEE: But I recall at Susquehanna you had a limitation --

MR. SCARBROUGH: Right.

MEMBER BANERJEE: -- which related to the relationship between the measured vibration and the stress -- the vibrations and the stresses. And if that exceeded a certain ratio, I forget what that magic ratio was, that was a limitation, right?

MR. SCARBROUGH: Susquehanna had the advantage of having direct dryer measurements. I mean, it's --

MEMBER BANERJEE: Yes, you have to run it on a model, whereas there you did not.

MR. SCARBROUGH: Correct. At Vermont Yankee?

MEMBER BANERJEE: Yes. But Vermont Yankee is quite a bit smaller than this, isn't it? I mean, what sizes are we talking about? Because this is a 3400 megawatt thermal plant. And what was -- 3339, or whatever.

MR. SCARBROUGH: Right. But the flow rates are on the same --

MEMBER BANERJEE: The flow rates are the same, but the dimensions are very different.

MR. MANOLY: But analytically it's the same approach.

MEMBER SIEBER: It's the same at Vermont.

MEMBER BANERJEE: Analytically it's the same approach, but it's a bigger dryer.

MR. MANOLY: Yes, that's correct.

MR. SCARBROUGH: Okay. So in terms of license condition number two, this is discussions of what actions they would take for certain situations.

If acoustic resonance challenges the limit curves, they re-evaluate the dryer loads, re-establish the limit curves.

The update dryer reports at 111.5 and 115.

DR. WALLIS: Can I go back? It says "Monitor RPB water level instrumentation." Now the water level surely isn't dancing at 150 Hertz or whatever it is. So what are you actually monitoring in this water level instrumentation?

MR. SCARBROUGH: You're evaluating the changes if you see a resonance starting to occur.

DR. WALLIS: The water level instrumentation is designed to measure level. It's not designed to measure high frequency.

MR. SCARBROUGH: Right.

DR. WALLIS: So does it tell you anything?

DR, HAMBRIC: This is Steve Hambric, Penn State.

The reactor pressure vessel water levels in Quad Cities actually showed that big 150 Hertz peak that caused all the --

DR. WALLIS: So there is a transducer which pick that up? Because it's usually designed to measure inches rather than frequency.

DR, HAMBRIC: Yes. You can pick up fluctuations. You have to be careful, because you do get extra frequencies that show up in the lines. But this is looking for just a disastrous peak --

DR. WALLIS: Okay. So it can do that.

DR, HAMBRIC: --that is not picked up in the main steamline strain gauges.

DR. WALLIS: Okay.

MEMBER BANERJEE: What's the mechanism for that?

DR, HAMBRIC: Big or high volume acoustic modes within the reactor pressure vessel is pulsing in and out. And you'll see that in water level.

MEMBER BANERJEE: And you couldn't pick that up in the steamline accelerometers?

DR, HAMBRIC: You should. You should.

MEMBER BANERJEE: But what happened there at Quad Cities? Did you pick it up in the main --

DR, HAMBRIC: You see it everywhere in Quad Cities. But when we get to the closed session there's a certain frequency that we're a little bit concerned about that we think may be a modeling artifact. But just to make it's not -- but just to make sure it is a modeling artifact, we want to measure the water level sensors and the reactor pressure -- so we'll revisit that in a closed session.

MEMBER BANERJEE: And the frequency that was being picked up at Quad Cities was what frequency?

DR, HAMBRIC: 151 and 156 Hertz.

MEMBER BANERJEE: And you saw that in the water level?

DR, HAMBRIC: Yes. Saw it everywhere throughout the --

DR. WALLIS: Yes, but it's not on the dial which says the level is 10 inches or 100 inches. I mean, that's the response time in seconds --

DR, HAMBRIC: Doing a frequency spectrum of the pressure --

DR. WALLIS: But that actually comes out of there. Okay.

MEMBER BANERJEE: And the water level sensors are what? Are they DP measurements? How are they being measured, the water levels? DPs?

DR. WALLIS: Well, they can't be measuring DP without frequency, surely.

MEMBER BANERJEE: It's probably just measuring acoustic waves then going through. Otherwise, how could they -- 150 frequencies seems a very high frequency to pick up --

DR, HAMBRIC: Well, we could share the

data with you if you like.

MEMBER BANERJEE: Yes, it would be interesting.

DR, HAMBRIC: There's a very clear frequency spectrum --

MEMBER BANERJEE: And how big were these fluctuations?

DR, HAMBRIC: Massive. Three orders of magnitude above any --

DR. WALLIS: No, no, no. I mean how big were the level fluctuations?

DR, HAMBRIC: Oh, I don't remember that.

MEMBER BONACA: Okay.

CHAIR ABDEL-KHALIK: Could you identify yourself?

MR. BILANIN: Yes, My name is Alan Bilanin from Continuum Dynamics Incorporated.

Quad Cities down in the instrument rack on the referenced legs, the water legs, there's plenty of ports where in fact transducers can be installed. And one of the first things that Quad Cities did when they were seeing flow induced vibration was make sure they had transducers there that can pick up this higher frequencies. They actually had an instrumentation system which was designed to look at any high frequency fluctuations up to 200 Hertz or so.

MEMBER BANERJEE: Were these DP or were they just absolute pressure?

MR. BILANIN: Oh, they're DP.

MEMBER BANERJEE: So you have seen fluctuations in DP, not just in pressure?

MR. BILANIN: That's correct.

MEMBER BANERJEE: How large were these fluctuations?

MR. BILANIN: It's been four years now. I don't recall, but I did have the data and I did analyze the data four years ago.

When we realized that there was a significant oscillation there, that's when the system was developed to place strain gauges around the main steamlines, and that became the method to measure the amplitude of the pressure fluctuations.

DR. WALLIS: I think I understand now. You're not really measuring fluctuations in water level. You're measuring pressure fluctuations at the end of the water level lines, which is quite a bit different?

MR. BILANIN: That's correct.

DR. WALLIS: Okay.

MEMBER BANERJEE: There's no way the water level could be -- beyond any science I've known.

DR, HAMBRIC: And there is over a fluctuation of 1 psi at Quad Cities.

MEMBER BANERJEE: So you're bouncing acoustic waves off, that's all you're measuring?

DR, HAMBRIC: Yes.

MEMBER BANERJEE: Okay.

MR. SCARBROUGH:

MR. PIERCE: So it terms of license condition number two, as I mentioned, they update the dryer reports. IF they challenge a limit curve, they perform a structural re-evaluation. They're going to be revising the plant procedures to reflect the long term monitoring for potential dryer failure.

They're revising the inspection program to match the BWRVIP-139 guidelines.

They're submit a final load definition once they complete the power ascension testing.

DR. WALLIS: There's nothing here -- excuse me -- about the moisture carry over that we had a discussion about. Were you here for that discussion?

MR. SCARBROUGH: Yes. That's part of --

DR. WALLIS: It is, but it doesn't appear to be part of your discussion here.

MR. SCARBROUGH: It's in the startup test procedure that they -- the next slide.

DR. WALLIS: Do you sort of agree with our conclusion that the water carry over, you know if something drastic happen, you might notice something but it's not as good of indication as these other indications?

MR. SCARBROUGH: Right. It's not as good as, you know, if you see a resonance, you're going to see it in the strain gauge data. And so that's going to be more proactive. Most -- after the fact. So that's why --

DR. WALLIS: It might indicate something catastrophic, you know.

MR. MANOLY: Yes, sudden rise step function then you would know this.

MR. SCARBROUGH: Right. But when they look for trends, that's one of the parameters they're going to be trending because there was an indication of data. And increase gets a lot of attention by the staff when we hear about it.

So license condition number three has the startup test procedure contents about it indicates the test procedures, it includes dryer acceptance criteria, the limit curve, the hold points, the inspections and walkdowns, the acceptance criteria and the verification for all those planned activities. So then that's laid out in much more detail in the license issue itself.

And then three more license conditions number 4 has to do with when you make aspects of the power ascension plan less restrictive. And one of those is the level 1 performance criteria where if you have a level 1 limit curve exceeded and the licensee wants to go back and adjust that level 1, you can't do that without NRC approval. So this is the same point that we raised with Susquehanna where there is this hold there where if you need to change that to show that you're meeting level, they have to come back to the staff.

The next license condition number five has to do with the visual inspection. It's this ongoing process for doing several dryer inspections using the BWRVIP-139 guidelines.

And then they provide the inspection results through a series of reports to us. There's a 90 day report after startup and then there is a 60--

DR. WALLIS: So they inspect the dryer while it's running.

MR. SCARBROUGH: No. During the refueling outage.

DR. WALLIS: Well, how can you get within a 90 day? You going to shutdown the plant within 90 days of startup to inspect the dryer?

MR. SCARBROUGH: Oh, that's startup following the outage to inspect the dryer.

DR. WALLIS: Oh, following the outage. Thank you.

MR. SCARBROUGH: Yes. Thank you. I was trying to crunch these licensing conditions down to just a slide. Sorry. So it comes out a little funny.

But after 90 days after startup they give those results. And within 60 days of completing the power ascension testing, they give us the dryer and structural integrity report. And then there's a supplemental report within 60 days once they finish all of the EPU power ascension --

MEMBER BANERJEE: So when are these inspections actually taking place?

MR. SCARBROUGH: During the fueling outage.

MEMBER BANERJEE: Which is when?

MR. DAVISON: Paul Davison.

The next refuel outage following the online implementation will be in 2009, spring.

March/April time frame.

MEMBER BANERJEE: And when will you be at full power if you ascended all the way up?

MR. DAVISON: Our target is June 1st of this year.

MEMBER BANERJEE: Okay. So it's about a year after, roughly, eight months or nine months or something like that?

MR. DAVISON: Approximately nine months.

MEMBER BONACA: Okay.

CHAIR ABDEL-KHALIK: Is there a condition similar to five after the cycle in which the full EPU is implemented? After the 15 percent?

MR. DAVISON: Yes. Yes.

CHAIR ABDEL-KHALIK: Thank you.

MR. SCARBROUGH: And then the last two license conditions we have there's an expiration--

MEMBER BANERJEE: Just -- the next refueling outage after the spring 2009 will be when?

MR. DAVISON: That would be the fall of 2011.

MEMBER BANERJEE: Okay.

DR. WALLIS: And seven means all license conditions expired or what?

MR. DAVISON: 2010.

DR. WALLIS: What's --

MEMBER BANERJEE: The fall of 2010 or finish?

MR. SCARBROUGH: All of the dryer inspections and they find no unacceptable flaws or unacceptable fatigue due to fatigue, that's when it expires. So there's --

DR. WALLIS: So all the license conditions one to six expire? But it doesn't say which license condition it expires.

MR. SCARBROUGH: Right. Yes.

Once they get to that point, they accomplish everything, the startup for power ascension testing is done, you know they've done all of that, they've done all the dryer inspections this is s way to sort of sunset all of these conditions.

MEMBER BANERJEE: "All the dryer inspections" means two refueling outages?

MR. SCARBROUGH: Right. All the way down.

DR. WALLIS: Don't you need to say license conditions expire, don't you?

MR. SCARBROUGH: Yes. It probably says that in the more detailed words.

DR. WALLIS: Okay.

MR. SCARBROUGH: But, yes, that's right.

MEMBER BANERJEE: So in time that would be fall to 2010 or 18 months after that?

MR. DAVISON: Yes, this is Paul Davison.

The next outage would be the September/October time frame of 2010.

MEMBER BANERJEE: And then if no flaws are found, then all these would expire at that point?

MEMBER STETKAR: IT would be spring of 2012. One more.

MEMBER BANERJEE: One more.

MEMBER MAYNARD: But also I believe they said they're not committing to go to the full EPU.

MR. SCARBROUGH: Right.

MEMBER MAYNARD: That may be delayed an outage or two. So those years flip out. Because it's two years after the implementation, two outages after the full implementation.

MEMBER BANERJEE: Oh, so the spring 2009 doesn't count here, that's what you're saying as an outage? They're going to do an inspection then, but they may not be at full licensed EPU at that point.

MEMBER MAYNARD: They will not be.

MEMBER BANERJEE: Will not be.

MEMBER MAYNARD: Will not be.

MEMBER BANERJEE: So only after they go to full license EPU, whenever that is, if they ever do, it'll be two outages after that?

MR. SCARBROUGH: Yes, sir. That's true. That's true.

And the last one there is the one I had mentioned earlier is we're providing the level 1 main steam safety valve vibration acceptance criteria before they exceed their current license level power just so they can make sure we have a baseline and they have criteria for monitoring that as well. And that comes from the Quad Cities issues regarding their electro-mater relief valves. So we had a concern.

So in conclusion for the open session, we talked about all the components that we went over, we considered that they'll continue to meet the general design criteria following EPU implementation.

There's reasonable assurance exists that the Hope Creek steam dryer is within its structural limits for CLTP and extrapolated EPU conditions. And we consider the EPU amendment acceptable with respect to component evaluation.

And then we consider the license conditions will establish provisions for monitoring and for evaluating plant data and taking prompt action if necessary.

DR. WALLIS: Of course if you were a probabilistic person you would caste this reasonable assurance in terms of a probability of success and not just in vague terms like reasonable assurance. It's very dangerous to assess the probability that there will be a problem with the dryer. And that's the way I would measure the success of your decision. If you said there's a chance of one in 100 and then it happens, or if you said there's a chance of one in a million and then it happens; that tells me something about the quality of your decision.

In this case you wouldn't hazard a probability of the dryer actually showing flaws after EPU?

MR. SCARBROUGH: No, sir. Because it was deterministic evaluation where the analyses showed that the fatigue limits would not be reached with the margins --

DR. WALLIS: So it's a judgmental thing? You just made a judgment.

MR. MANOLY: Deterministic.

MEMBER BANERJEE: It depends a lot on the loads that the calculation, that's extrapolating significantly from the current database based on some form of modeling.

MR. SCARBROUGH: Right.

MR. MANOLY: And benchmarking. Against Quad Cities.

MEMBER BANERJEE: Well, but it's not the same as Quad Cities. I mean, we've been through this argument with Susquehanna in detail where Quad Cities is very different in some ways than these dryers are. I mean, you have a frequency of 150 whereas the Susquehanna dryers you had 15. I mean --

MR. MANOLY: But the tool is being used, that's what we're --

MEMBER BANERJEE: But the tool was not the same thing either. It was being revised continuously, if I remember, at least at the time of Susquehanna

MR. SCARBROUGH: We'll talk about that revision again during closing.

CHAIR ABDEL-KHALIK: At this time we'll take a 15 break and reconvene at 10:45 for a closed session.

(Whereupon, at 10:30 a.m. a recess until 10:46 a.m.)

CHAIR ABDEL-KHALIK: Before we switch to a closed session, the licensee and its consultants would like to present some information that was requested during the earlier session. So, thank you.

MR. SCHROLL: I'm Ed Schroll. I'm from GE-Hitachi. The information is on the Susquehanna steam dryer.

The Susquehanna steam dryer, the new one, the plates and channels have been beefed up by approximately two times what the original dryer was.

Also, in that new dryer we have used non-sensitized material to avoid IGSCC.

Also another modification has been to remove most of the fillet welds and replace them with full penetration welds.

CHAIR ABDEL-KHALIK: Thank you. If there is any additional information you would like to present in the open session? No?

MR. DAVISON: No.

CHAIR ABDEL-KHALIK: Okay. So at this time we will go into a closed session.

(Whereupon, at 10:47 a.m. the meeting went into a closed session to reconvene in open session at 3:00 p.m.)

CHAIR ABDEL-KHALIK: We are back in session. This is an open session. Before we get started, the applicant would like to make a statement about a table that was distributed.

MR. DAVISON: Yes, Paul Davison, PSEG.

On the first day we handed out a chart that looked like this for the power ascension testing. This updated chart that we provided to show all the way through 115 percent that was the second chart we handed out today with the packet, we made a transcription error in the moisture carryover column. It shows an X in every percent power. They are two and a half percent increases. We will provide Zena an updated chart to reflect that error for the second graph that we provided.

MEMBER ARMIJO: So there should be some blanks there?

MR. DAVISON: That is correct.

MEMBER BANERJEE: Two and a half percent?

MR. DAVISON: Correct.

CHAIR ABDEL-KHALIK: At this time we'll continue with the presentation. And the staff will begin the presentation with item number 19 on the agenda.

19. PLANT SYSTEMS

NRC STAFF REVIEW OF EPU TEST PROGRAMS

MR. PETTIS: Good afternoon. My name is Bob Pettis. I am with the Quality and Vendor Branch, which is a part of the Division of Engineering in NRR. And I have a brief presentation on the staff's review of more of the programmatic aspects of our ascension testing program with some emphasis on the transient testing issue.

On the second slide, we just have a little introduction. And the standard review plan is used by the staff to perform its review in this area. It's SRP 14.2.1, titled "Generic Guidelines for Standard Power Uprate Testing Programs" specifically developed for EPUs. It provides guidance for the staff reviews of the proposed EPU test programs. Its primary basis is based on reg guide 1.68 requirements, which were in place for initial plant test programs.

Just in the way of a little history, the SRP was developed back in the 2003 time frame. There was a final version that was published by the staff in 2005. And we have had several meetings with the Committee with respect to the content and the philosophy embodied in the standard review plan.

The reason for its development, it had to do with the development of the review standard, which is used for all power uprates, which is RIS-001. And basically at the time that the review standard was being developed, we needed an extra piece of proceduralized guidance in order for us to do a comprehensive review for EPU. So as part of the review standard process, this document was developed.

In general, the EPU test program should include sufficient testing to demonstrate that SSCs will perform most satisfactorily at the proposed uprated power level. The EPUs to date that the staff has reviewed has been somewhere on the area of about 19 to 20 total in the EPU category, which is basically the requests that are above 7 percent.

Staff guidance considers the original power ascension test program and the extent of any EPU-related modifications. The SRP guidance acknowledges that licensees may propose alternative approaches to testing, which would have to have adequate justification.

Specific review and acceptance criteria are provided in the SRP for the staff evaluation. That refers to section 3(c) of the SRP, in which we have a series of criteria. It is about six to seven that the staff uses as a means of evaluating any justifications for not performing certain original start-up testing.

Our group, which is in the Division of Engineering, primarily we look at the programmatic aspects of the power ascension test program. And then we receive technical inputs from other technical branches.

In this presentation, which is a short presentation for today but it embodies about 15 or 18 pages of the safety evaluation -- and so just so that you're aware, there are inputs from the Plant Systems Branch along with Reactor Systems Branch and some input from the PRA Technical Branch as well. So it's a consolidated review. And basically all of that detail is contained in the safety evaluation.

The program at Hope Creek consists primarily of steady state testing, does not include performance of large transient testing, which has been defined as the MSIV closure test and the generator load rejection test.

These two tests have been included back in the General Electric topical report, which was the LTR-1. We have had discussion probably for the last five to six years with respect to performance of these tests. And for the bulk of the BWR applications, they have basically all addressed the same criteria, which is General Electric's CPPU guidance and also plant performance of the rest of the BWR fleet.

The test program will monitor important plant parameters during EPU power ascension. Tech spec surveillance and post-mod testing will confirm performance capability of the modified components.

The power ascension follows staff-approved GE CPPU topical report. The staff wrote a safety evaluation back in about the 2005, 2004 or '05, time period, which was a review of the GE CPPU topical report.

PSEG's justification for not performing the two large transient tests: address the review criteria discussed in SRP 14.2.1, which is consistent with previous staff-approved EPUs. These criteria basically are the ones that I described earlier that are in section 3(c) of the SRP.

Some of the justifications include industry operating experience, including unplanned events at Hope Creek involving turbine trips and generator load rejection, which produce expected results. I don't believe there are any MSIV events that I can remember back that we could add to this. They were basically turbine trips or generator load rejections.

No new thermal hydraulic phenomena or new system interactions were identified; the limited scope of EPU mods for balance-of-plant systems, again, using the CPPU approach.

Transient evaluations were performed by

GE, included large transient testing at full EPU conditions, which is referenced in the Hope Creek power uprate safety analysis report, no unique limitations associated with conformance to analytical methods.

Our technical counterparts and their reactor systems have been busy over the years looking at whether or not the performance of these two tests, the MSIV and the generator load rejection, were needed to validate any of the existing plant safety codes that are used in the EPU approach. And it keeps coming up that they are not needed for code benchmarking or validation.

PSEG's conformance to NRC staff-approved GE LTRs, again, the staff approved the LTR-1 and the LTR-2 and the CPPU topical approach.

The staff summary is that the SRP allows for the justification of the transient testing is not needed for code analysis and benchmarking, which is consistent with previous plants, with the exception of Browns Ferry unit 1, which was the only other plant that we required for a license condition that they do the testing.

The staff considered the operating history at the plant, industry experience within the BWR community, and the fact that there is no introduction of any new credible thermal hydraulic phenomena; limited scope of EPU mods; and conformance to the staff-approved GE topical report.

And, in conclusion, the proposed EPU test program satisfies the review and acceptance criteria that's contained in 10 CFR 50, appendix B, criterion XI, which is "Test Control," and that the proposed EPU test program addresses the guidance and the review criteria established in the SRP for EPUs.

CHAIR ABDEL-KHALIK: Thank you, Mr. Pettis.

MR. PETTIS: Okay.

CHAIR ABDEL-KHALIK: Are there any questions for Mr. Pettis?

(No response.)

CHAIR ABDEL-KHALIK: If not, we'll move on to item 20 on the agenda. And I ask the applicant to make that presentation.

20. PROBABILISTIC SAFETY ASSESSMENT

DR. BURNS: Good afternoon. My name is Ed Burns. I am the Hope Creek risk management team technical leader. And I am responsible for the Hope Creek PRA development implementation and its applications. Thank you for this opportunity to discuss the effects of EPU and the Hope Creek risk profile.

The next slide, the first slide, identifies the purpose of the EPU risk evaluation. What we want to do is provide a risk perspective regarding the effect of EPU implementation using standard probabilistic risk assessment techniques to complement the deterministic licensing requirements and to confirm the appropriateness of the changes. This is accomplished by estimating the change in full-power internal event CDF and LERF produced by EPU implementation.

We are using the available probabilistic models for Hope Creek. And we shall also identify qualitatively the changes in risk from other sources; for example, external events and shutdown configurations produced by EPU implementation using insights from Hope Creek.

The results are compared with the reg guide 1.174 for the risk significance of the changes where the significance is described by acceptance guidelines and the risk matrix defined by the NRC.

The next slide gives an overview of the risk evaluation process. This is a summary of both the process and the guidance we used, plus the risk matrix that we used. First of all, the EPU submittal is based on deterministic evaluation of licensing criteria and is not a risk-informed submittal. Nevertheless, the quantitative risk perspective is developed and is based on reg guide 1.174, which provides quantitative measures and acceptance guidelines for use by decision-makers.

Quantitative risk matrix chosen by the NRC in 1.174 are the core damage frequency and the large early release frequency. These acceptance guidelines consider both the initial values and the magnitude of changes in CDF and LERF.

As a note, the baseline CDF and LERF must be below thresholds to make a plant eligible for the changes to the regulatory licensing process. And the Hope Creek CDF and LERF are sufficiently low to allow consideration of these changes by the NRC.

The next slide summarizes the topics for the presentation, which are aligned directly with the EPU risk evaluation methods. We first identify the plant configuration and procedural changes that were part of the EPU upgrade. And then we use the updated PRA models. The PRA models are developed consistent with the ASME PRA standard and incorporate peer review comments.

We then identify those PRA elements affected by the changes, such as the success criteria, the human errors, and initiating event changes. Once this is completed, we then incorporate the EPU hardware and procedure changes in the PRA model along with using realistic success criteria and limits as part of the model implementation.

Finally, the PRA model quantification is performed on the current plant and the EPU plant to calculate the change in risk matrix. And the results compared with the reg guide 1.174 acceptance guidelines.

Next slide. The identification of the changes with potential to influence the risk profile can be then correlated with possible PRA elements affected. The predominant influence on the risk changes is derived from the increase in power level and the associated reduction in margins, feedwater response issues, higher nominal flows, reduced reaction times in the power ascension testing.

Those influences can change the success criteria, the human reliability analysis, the system fault trees that feed into the accident sequence analysis, and the core melt progression timing.

MEMBER STETKAR: Ed, can I interrupt you

--

DR. BURNS: Sure.

MEMBER STETKAR: -- for just a second? I read through all this stuff. It makes a lot of sense. I really like your models for SRV challenges and things.

I have one question. Does the increased power level -- I don't know how HPIC/RCIC are controlled here at Hope Creek. Does the model include cyclic behavior of HPIC/RCIC and other --

DR. BURNS: Yes.

MEMBER STETKAR: -- pull a high-level trip?

DR. BURNS: Yes.

MEMBER STETKAR: Does the increased power level increase the number of cycles of RCIC, for example, for transient response? It would seem that it would.

DR. BURNS: We include a number of cycles for HPIC and RCIC before the operator takes control, but he's directed. And I'll defer.

MEMBER STETKAR: So you do have an operator action to manually control flow also?

DR. BURNS: Yes.

MEMBER STETKAR: Because I didn't see

either of those things in your discussion of delta for pre-EPU/post-EPU, either number of cycles before he takes control or even in the HRA a time window for him to take control. It was one of the questions I had about --

DR. BURNS: Right.

MEMBER STETKAR: -- the deltas.

DR. BURNS: Right. We included the top 20 --

MEMBER STETKAR: Operator actions.

DR. BURNS: -- operator actions based upon importance. In preparation for this and subsequent to the calculations that were done for the EPU submittal, we went back and looked at all of the HEPs to see what they were. But even then, that operator action was below the risk achievement worth that we looked at for those cases.

MEMBER STETKAR: At the value that you would use --

DR. BURNS: Right.

MEMBER STETKAR: -- before? Let me ask, do you know or does someone at Hope Creek know -- it relates to a different question that I have also on systems level -- the number of -- if you just modeled RCIC behavior, operator hands-off until you get down to RHR entry conditions, how does the number of RCIC cycles change over that period pre-EPU versus post-EPU?

MR. KOPCHICK: Sir, this is Bill Kopchick. I am a shift operations superintendent at Hope Creek.

Would this be under an appendix R-type shutdown from remote shutdown panel?

MEMBER STETKAR: No. I'm talking about normal transient response. Take an MSIV closure, vessel isolation event. And have you run out transients to look, operator hands-off, number of RCIC cycles, pre-EPU versus post-EPU?

MR. KOPCHICK: I wouldn't be able to answer whether or not we would do that operator hands-off. The expectation for the operator would be to take control of the RCIC system or the HPIC system if required under, say, a small break LOCA condition and adjust the flow controller.

MEMBER STETKAR: Okay. Let me get back to Ed, then. In the PRA model, do you do that after the first cycle, after the first trip and restart or --

DR. BURNS: We include ten challenges, so ten cycles and then --

MEMBER STETKAR: Ten cycles. Okay.

DR. BURNS: Ten cycles for both.

MEMBER STETKAR: Have you got any idea what the time frame -- then I'll ask it to you this way. Have you got any idea what the time frame is pre-EPU versus post-EPU to get those ten cycles?

DR. BURNS: I think that it's on the order of four hours.

MEMBER STETKAR: Okay. Thank you. Continue.

DR. BURNS: The configuration changes associated with the EPU changes involve the BOP arrangement flow margins again, recirc runback. And those can influence the HRA. The system fault trees are the initiating events.

The hardware changes include physical changes. Those are mostly changes in kind, some reliability changes and set point changes. And those can affect the accident sequence response system fault trees and initiating event frequencies.

Procedure changes, which in terms of the PRA or the risk analysis, the ones that were of most interest were the ones that affected the EOP limit curves for pressure suppression pressure in HCTL. And those occurred later in the accident sequences where the change in risk was very small.

Next slide.

DR. WALLIS: Let me ask you this time. When we see other power uprates, usually what seems to dominate the change in risk is the reduced time available for human action. Is that the case here?

DR. BURNS: The dominant contributor here is the time available for operator action, yes.

DR. WALLIS: So it's the same as at other plants, right?

DR. BURNS: Correct. I can't say numerically, but it's --

DR. WALLIS: No, but it's qualitative. It's the dominant --

DR. BURNS: It's the one in this. So those are the plant changes. Now the updated PRA model I would like to talk about. The Hope Creek PRA model scope and quality are adequate to provide a realistic perspective on the EPU implementation. And the following description in this slide is the basis for the PRA pedigree.

We are using the internal events PRA developed in accordance with the ASME PRA standard to meet capability category II. Historically the PRA subsequent to the IPEEE had been subjected to an industry peer review conducted in 1999. And that peer review was then incorporated into a rather extensive model modification that was performed in 2003 to resolve all of the peer review recommendations and to formulate a model to meet the ASME standard.

This was confirmed by a PRA self-assessment against the standard addendum B in June 2006, when we confirmed that 92 percent of the supporting requirements mete the capability category II, where our conclusion was that that was consistent with the PRA quality that was commensurate with the role the PRA plays in decision-making.

In addition to that for the other hazards, we use the IPEEE insights for external events in the plant-specific shutdown evaluation plus other PSAs for shutdown conditions to address but not to quantify the risk associated with those hazards and configurations. These other hazards are assessed to be very small contributors to the delta or change in risk associated with the EPU implementation.

Next slide. So that's the base PRA Model and the changes. Now I would like to consider how those identified changes influence the --

DR. WALLIS: Let me ask you -- I'm sorry. Your CDF is very low, relatively speaking.

DR. BURNS: No, no.

DR. WALLIS: Isn't it?

DR. BURNS: The CDF is about in the middle or in --

DR. WALLIS: The middle.

DR. BURNS: -- the top of the base CDF for BWRs.

DR. WALLIS: Do you recall an estimate of the fire risk?

DR. BURNS: I can talk about fire risk.

DR. WALLIS: It's close to -5. Okay. Is fire risk comparable with these internal events?

DR. BURNS: The internal events PRA is developed according to an ASME PRA standard. There is no standard for the fire analysis.

DR. WALLIS: But there is an IPEEE. So you have made estimates of fire risk, right?

DR. BURNS: There was an IPEEE analysis that was actually quantified --

DR. WALLIS: Do you know if the fire is comparable with the --

DR. BURNS: That analysis showed that the fire risk was significantly larger than the internal events PRA. However, in my judgment, the conservative biases that are in that fire analysis make the comparison misleading.

DR. WALLIS: Yes. But it still is

impressive how big it looks.

DR. BURNS: Yes.

DR. WALLIS: Is there anything in the EPU that would significantly enhance the fire risk?

DR. BURNS: We looked at the fire analysis in the following way. We didn't see any increase in combustible loading that would be an issue. We didn't see any new fire-initiating events that would increase the fire frequency.

We looked at the changes in the PRA that we implemented as part of EPU to support the internal events. If you do that, then that conditional core damage probability when applied to the pervious fire analysis would reduce that fire frequency by a factor of four.

We also looked at --

MEMBER STETKAR: How did you make that determination?

DR. BURNS: Well, if you transferred the conditional core damage probability from the internal events to --

MEMBER STETKAR: You're the source of that calculation?

DR. BURNS: No.

MEMBER STETKAR: Okay. I'll beat up the

guys who are, then, later. How did you make the -- you said a reduction of core. That's a nice number. It means you must have done some analysis or is that reduction of core strictly related to the ratio of the internal events total CDF?

DR. BURNS: It's strictly related to the --

MEMBER STETKAR: So there's no basis for that number?

DR. BURNS: No. I disagree that there is no basis, but --

MEMBER STETKAR: Well, given the fact that you have modeled most of the fires as losses of off-site power or MSIV closure-initiating events, there is no reason to believe that an average change in the internal event core damage frequency has any relation to the types of scenarios that are initiated by fires.

I've just made my point. Let me ask a question in a different way.

DR. BURNS: I can tell you why I think the fire analysis is biased.

MEMBER STETKAR: I understand why it might be biased. Let me ask probably what Graham is looking for also in a little bit different way. When you compared the seismic risk, which is also derived from some approximate IPEEE model, as I read, the RAIs and responses, to me a reasonably convincing argument -- you went through five scenarios, and you said, "Here is the difference between the IPEEE sort of understanding, the pre-EPU PRA model" and then "Here is how we would expect the pre-EPU, the post-EPU." And some things are not affected because seismic fails everything. A couple of the sequences were affected. And there was a fairly compelling argument, semi-qualitative, semi-quantitative.

Why didn't you do the same thing for the fires? There are only 16 scenarios.

DR. BURNS: We did do that. What we looked at was examined the critical fire scenarios from the IPEEE and those sequences where we had a loss of equipment or access to equipment as a result of the fire. And, therefore, whether it was pre-EPU or EPU didn't make a difference in those cases because the timing wasn't a factor because I didn't have access to controlling that equipment.

Those accounted for approximately 75 percent of the fire risk profile.

MEMBER STETKAR: Does that mean the fire led directly to core damage or --

DR. BURNS: Right, correct.

MEMBER STETKAR: Ah. Okay.

DR. BURNS: And then a portion of the remaining 25 percent were related to a loss of DHR sequences, where I do have an extended period of time to take some action to respond to the event.

So that analysis or that evaluation of what existed as the dominant contributors in the fire PRA from the IPEEE plus our assessment of what conservative biases existed in the analysis related to both the initiating event frequencies for fire, the fire damage models, the treatment of human error probabilities, and response to accidents, fire-induced accidents and the fire suppression capability that wasn't realistically incorporated led us to the belief that the total fire contribution was significantly below the previous one and that the delta fire risk was comparably low.

For this particular topic, though, I'm less interested in the total as I am in the delta --

DR. BURNS: Correct, but the total --

MEMBER STETKAR: -- pre-EPU and post-EPU.

DR. BURNS: -- total does influence the delta.

MEMBER STETKAR: That's true, but I am

interested to understand how the fire risk changed pre-EPU/post-EPU first and a convincing argument to tell me, did it increase? And my best estimate is that it would increase because of shorter time windows, slight changes in some of the success criteria.

The magnitude of that increase, the absolute magnitude of that increase, is a different subject.

DR. BURNS: Right.

MEMBER STETKAR: And in the things that I read, I didn't find a convincing argument to tell me that it would increase pre-EPU to post-EPU or any way to give me an idea, would it increase by a small amount, a moderate amount, or reasonably large amount.

And I'm not talking about an absolute number. I don't care whether it's 10^{-4} or 10^{-5} or 10^{-6} or 10^{-7}. I'm looking for a systematic discussion, kind of in the same way as the seismic.

DR. BURNS: I just gave you my best shot, which was that --

MEMBER STETKAR: But in what I read, I mean.

DR. BURNS: Oh. Sorry.

MEMBER STETKAR: Was it submitted? I

couldn't find anything in what I read.

DR. BURNS: It's not in what was submitted in the RAI or in the submittal.

MEMBER STETKAR: Okay. Go on ahead and finish your presentation. I will attack it from the other direction.

DR. BURNS: Okay. So we were attempting to incorporate the changes that we have identified as part of the EPU implementation into the PRA model that we have upgraded to meet the standard.

And the risk profile changes associated with EPU implementation are manifested by changes in the initiating event frequency, the success criteria, changes in operating interface modeling, changes in systems and system reliability, and changes in sequence timing.

So we modified the initiating event frequency to reflect the potential for increased challenges due to reduced balance of plant margins and by increasing the initiating event frequency for turbine trip specifically.

There were slight changes in the system success criteria for RPVD pressurization, ATWS overpressure. And we also modified the number of SRV challenges based on the deterministic calculations we did for EPU.

There was no significant impact associated with the hardware changes because the new equipment was replaced in kind with like equipment. However, we did modify the SRV probability based upon the increased number of cycles.

There were no changes to ECCS or diesel generators. There were no new accident sequences that we identified. One of the principal influences, as Dr. Wallis identified, was associated with the reduced time available for crew diagnosis and execution for the time-critical actions. And that was included in the revised human reliability analysis.

There was no significant impact due to the changes in HCTL or pressure suppression pressure. And the core melt progression times were reduced based on the deterministic calculations that we did, but there was no change in the LERF calculated as a result.

MEMBER STETKAR: Ed, let me just add one in passing. I hope you have a quick answer. You have a conditional loss of off-site power value given a plant trip.

DR. BURNS: Yes, yes.

MEMBER STETKAR: Why is a different value used for LOCA signals and non-LOCA signals?

DR. BURNS: I think there were -- historically what has happened is that there was a Brookhaven NUREG that identified a difference in the two values. And it was based on very sparse data. So it was somewhat questionable that that data supported that difference.

Subsequent to that, EPRI had an expert panel that was convened to look at the values that Brookhaven had come up with. And the EPRI expert panel identified that there was, in fact, a potential difference associated with the -- and it had to do with the loss of VARS and the feedback from the grid. But subsequent to that, the NRC also revised their numbers in a SECY document more consistent with the EPRI analysis.

Recently, though, 68.90, for example, has a single value in it, as opposed to the two values.

MEMBER STETKAR: Because the 68.90 is more derived from historical experience.

DR. BURNS: Right.

MEMBER STETKAR: I was just curious if there was any real -- I don't understand why there would be a factor-of-three difference.

DR. BURNS: The original issue arose because the theory was that for a LOCA or an event that had a LOCA signal associated with it, that what you were doing was you were losing a plant and you were starting the large ECCS loads at the same time. That was the original theory. And that loading of the grid was supposed to -- that was the original theory.

MEMBER STETKAR: Okay. Thanks.

DR. BURNS: In summary, implementing this model changes gives the following quantitative results. For the change in CDF, we get 6.80 minus 7, which reg guide 1.174 characterizes as very small, which is the lowest risk significance category allowed in 1.174.

Similarly, the results for LERF. On the next two slides, I have this graphically displayed to --

DR. WALLIS: I would just like to make a point for the staff. I think the SER says that the change in CDF was 4.2 percent. It seems to me that 6.80 minus 7 over 9.4^{-6} is something over 7 percent. So the SER should reflect that, rather than the 4 percent, which didn't seem to come from anywhere that I could find.

DR. BURNS: I think that's correct, yes.

These slides are just a graphic display of those quantitative results, which show that the position of the change in CDF and change in LERF associated with the EPU implementation places the risk in the risk region III, which is identified as a very small risk change.

So, finally, that's the LERF one. The next slide identifies the, the next slide, Vince, identifies the, risk assessment, provides confirmatory insights to those developed from a deterministic analysis. The risk impact was evaluated using standard PRA methods. And the quantified risk impact is a small percentage of the current plant risk.

DR. WALLIS: Let me ask you something. Did you do uncertainty analysis on this?

DR. BURNS: Of course, uncertainty can be divided into parametric uncertainty, modeling uncertainty, and completeness uncertainty. We did the parametric uncertainty analysis quantitatively and the modeling uncertainty analysis in a sensitivity calculation.

DR. WALLIS: Which uncertainty did you discover when you did that?

DR. BURNS: The range factor was a factor of three.

DR. WALLIS: Factor of three.

DR. BURNS: 2.9, I believe.

DR. WALLIS: Factor of three on?

DR. BURNS: I'd have to look at the exact number.

DR. WALLIS: On CDF absolute value or change?

DR. BURNS: On the absolute value.

DR. WALLIS: So the change is less within the uncertainty? Yes?

DR. BURNS: Yes.

DR. WALLIS: Way within the uncertainty.

DR. BURNS: Yes.

DR. WALLIS: You are uncertain by a factor of three. And you are looking at a change of seven percent. Interesting.

DR. BURNS: In conclusion, the Hope Creek risk profile is appropriately characterized by the PRA consistent with the ASME PRA standard. And the quantified results reflect the very small risk impact associated with the EPU implementation.

Thank you very much for this opportunity.

DR. KRESS: Does your PRA have the capability for a full level 3 if you need it?

DR. BURNS: Currently the PRA for level 2 only has large early release frequency, but we are --

DR. KRESS: No fission product transports?

DR. BURNS: We are undergoing an update right now which will convert it to full level 2, which will have the spectrum of radionuclide releases that can then feed into --

DR. KRESS: Into a MACCS.

DR. BURNS: Feed into MACCS, correct. And that should be done in June.

DR. KRESS: Do you plan on doing a level 3?

DR. BURNS: We're preparing for a level 3 in case there is a license extension submittal.

DR. WALLIS: I think you also did a qualitative shutdown risk evaluation?

DR. BURNS: Yes, sir.

DR. WALLIS: And that didn't lead to any surprises. You just had a little bit shorter time to do things because it boiled up quicker and so on?

DR. BURNS: Yes. Because the time is so long associated with the shutdown conditions, the delta in the human reliability analysis is extremely small.

DR. WALLIS: Do you have an estimate of how this shutdown risk compares with the internal events risk?

DR. BURNS: No, sir.

DR. WALLIS: It could be comparable?

DR. BURNS: No, sir. We don't have a quantitative assessment for --

DR. WALLIS: No quantitative estimate. So we don't know what it is, but we know that it didn't change very much.

DR. BURNS: Yes, sir.

DR. WALLIS: Okay.

CHAIR ABDEL-KHALIK: Thank you, Mr. Burns.

At this time we will move on to presentation item number 21 on the agenda.

21. RISK EVALUATION

MR. HARRISON: Good afternoon. My name is Donald Harrison. I am with the Balance of Plant Branch now. And I was right with Marty Stutzke. He was the actual PRA reviewer for the Hope Creek application. I will also recognize that Mark Rubin's at the side table. He's the PRA Branch Chief.

What I am going to do is given that Dr. Burns presented the Hope Creek analysis, I am not going to repeat his analysis and describe that. I am just going to go into what the process of our review was, especially for some of the ACRS members that may be new members to the Committee. So, with that, we will start with the conclusion.

This is not a risk-informed application. And the submittal is looked at in a unique fashion if it's not risk-informed. And we are actually evaluating the risk information.

We are looking for what is called special circumstances that would rebut the presumption of adequate protection. So the focus is on adequate protection, reasonable assurance of adequate protection.

In this review, we did not find any such special circumstances. We'll get into what it means to have special circumstances and how we do our review.

And, again, this is a summary. Hope Creek is not risk-informed. Therefore, it's not evaluated by the staff against the SRP 19.2 or reg guide 1.174. However, that guidance is used as, if you will, some help in doing the review, help for the licensees in actually making their submittal.

The application is actually reviewed against the review standard, 001, rev. 0, maybe a rev. 1 by now, -- I'm not sure -- Matrix 13, which is the risk evaluation section.

A review is done consistent with SRP section 19.2, appendix D. And that appendix is specifically written for the use of risk information and reviews of non-risk-informed license amendments, which extended power uprates is one.

In doing that review, we determined that a special circumstance exists that, again, could rebut the presumption of adequate protection. In also doing that review, we also confirmed that the risk values are acceptably small.

Here are some definitions. Issues that could rebut the presumption of adequate protection. This becomes the definition of what is a special circumstance.

Within that appendix D, it provides two basic situations that you could be in that could result in that. One is if you identify an issue that wasn't addressed in the original writing of the regulations and the guidance. And it could be important enough that it would warrant rewriting the rules, rewriting the regulations to address this issue.

DR. WALLIS: Such as discovering that the steam dryer is risk-significant?

MR. HARRISON: The situation in that, what you do is if you found that that was a critical issue and it needed to go back and we had to rewrite the regulations, one way to look at that would be to go back and do that.

What has happened subsequent to the Quad Cities is, again, there are a number of different methods that have been addressed. You have heard extensively on the different methods and how the Deterministic Branch is addressing those issues so that we're not going into writing regulations. But you're right. That would be some type of consideration.

A typical example here would be if someone is using a material, a unique material, in an application that hadn't been thought of before. They meet the regulations. But with these material properties, we're not really sure what to do. I think that may have actually been the genesis of the special circumstance process in the first place back in the 1990s.

The second one -- this is where most of our effort is spent -- is if the actual staff reviewer has knowledge that the risk impact is not being reflected in the licensing basis and that if it had been reflecting this, this had been risk-informed, we would have grounds to deny the application on the risk basis. And, again, this is what drives why the applicant makes the submittal they make and why we spend most of our time.

You are not expected to be able to read this chart.

(Laughter.)

MR. HARRISON: Sorry. Just recognize on the right-hand side, there is --

DR. WALLIS: Not only is it expected. It's completely impossible.

MR. HARRISON: Well, on a white piece of paper, you can almost make it out. That's the background that gets you on that one.

This picture logic is actually in appendix D to section 19.2. So if you're more interested, you can actually go there and look at it. We are going to spend the next couple of viewgraphs actually walking through the first couple of diamonds in this plot.

What this is, this is the flow logic of how we do our review. You come in with an application that's not risk-informed. It's at the very top. The very first diamond says, "Do you have special circumstance?" If the answer is "No," "Did the staff identify it?" If the answer is "No," you would end up on this chart going to the right. And it says the application is acceptable. As you go through, you will see at eery diamond, if you go to the right, the application is acceptable.

If the staff identifies an issue that raises the topic of special circumstance, we don't just deny the application. What we then do is inform --

DR. WALLIS: You don't assess it against reg guide 1.174, but, yet, you do.

MR. HARRISON: Eventually. And you'll see that as we go through. And, again, at this level, we get the risk information from the applicant. We look at it. And, again, what we're looking at is, is there any issue that we are aware of that would make the risk much more significant than what is being portrayed and that would make it actually an unacceptable application.

DR. KRESS: Do the safety goals enter your review at all?

MR. HARRISON: Not directly. What we're doing is -- and, again, I am using the word "risk." What I am really meaning in our approach is core damage frequency and large early release frequency. So those were the surrogates for the actual QHOs and measures. So we do not do a --

DR. KRESS: So it is an indirect?

MR. HARRISON: It is an indirect. It is not direct. It doesn't do a direct comparison.

That being said, the very first block, again, this is showing the logic here. The first diamond asks, you know, essentially, "Do you have an issue that could rebut the presumption of adequate protection?" In other words, do we think we have special circumstance?

If you go to the right, the application goes on. We terminate our review at that point. If we think we do, we go on down.

Now, just as a point -- and I think Bob Pettis said there have been 20 power uprates, extended power uprates. We have never gone through the yes part of this block on any extended power uprates that we have reviewed.

And, just as a point of reference, Marty and I have been the risk reviewers of every power uprate, extended power uprate, for about the last six years. So the two of us are kind of the ones that have been doing this process.

If you go through again the process and we find we have special circumstance, we notify our management. We also notify the licensee at that time.

And, just as an aside, if we did that, at that point I think we would probably notify projects that the schedule has just been blown.

DR. WALLIS: Don, can I ask you something? When you seem to be just quoting the numbers quoting to you by the licensee, did you do some independent checks that what he did was reasonable?

MR. STUTZKE: If you want to jump ahead to the table of results, those numbers for independent fire and seismic are my estimates.

DR. WALLIS: They are your estimates?

MR. STUTZKE: Yes, sir, imperfect as they are.

DR. WALLIS: Well, then tell me --

DR. KRESS: Did you use the SPAR models for that?

MR. STUTZKE: No. I started with licensee's information from IPEEE, very simple.

DR. KRESS: I see.

DR. WALLIS: So the previous slide, where he estimates the change, internal events, you just accept as --

MR. STUTZKE: Yes.

DR. WALLIS: There is no reason not to, is there?

MR. STUTZKE: Based on the review.

MR. HARRISON: Well, we do a review. I mean, it's not that they send it to us and we just check off.

DR. WALLIS: Well, the question might be, did he evaluate his human error probability reasonably? Did he use some wild model for human error probability?

MR. HARRISON: Do you want me to? Marty during his review I know this is --

DR. WALLIS: Did you use EPRI model or something like that? What did you do?

MR. STUTZKE: Okay. So in order to do the review of the human reliability, I went to NUREG-1842, which is the so-called HRA good practices document. It's out. This is one of the first chances we have had to utilize the document. So you go down through all the points.

The idea of that document, you know we have a PRA standard, which tells you what you ought to do. This document tells you how you should go about doing it.

DR. WALLIS: How to do it, yes.

MR. STUTZKE: Okay? Specifically to the licensee here, they used two methods to quantify their HRA. They used either the cost-based decision tree methods or ASEP. That's for the cognitive portion.

You wanted to use ASEP when you are time-limited, generally less than 60 minutes. It's what used to be called the time-reliability correlation curves. You pick off the available time without the probability of failure.

Cost-based decision tree looks at other sorts of shaping factors, procedures, training where the time is not driving that reliability. All of these methods were implemented in the EPRI HRA calculator. It's nothing more than a quantification tool.

DR. WALLIS: So you did check that he was using reasonable and approved methods.

MR. STUTZKE: Yes.

MR. HARRISON: And, just to clarify, the NRC has never approved an HRA method, but their --

DR. WALLIS: No. I think that's one of the matters for discussion in another subcommittee.

MR. HARRISON: Right. And I just want to clarify because you mentioned the word "approved."

DR. WALLIS: I'm sorry. Yes. You are right.

MR. HARRISON: We recognize the models. We are familiar with them --

DR. WALLIS: You accept without approval.

MR. HARRISON: We accept them, right.

DR. WALLIS: Yes.

MR. HARRISON: Just to clarify that. So okay. And since Marty got us here, actually, for the internal events results, the information is the same as what the licensee provided.

I think I made the big deal a few years ago to only present these as single significant digits. So we'll round it off from where the licensee provided the information.

So, again, the internal fires and seismic events Marty discussed, we can move on to --

MEMBER STETKAR: Yes. Let me stop you there.

MR. HARRISON: Okay.

MEMBER STETKAR: I saw what you did. And it's -- well, I'll be not tactful. It's not technically justified. It's an absurd calculation. And it should not be published in the SER, period.

DR. KRESS: You weren't very tactful, were you?

MEMBER STETKAR: I said I wouldn't be tactful.

DR. WALLIS: This is the first endorsement

I've heard in a long time.

(Laughter.)

MEMBER STETKAR: So I don't particularly want to understand the basis for it because there is no technical basis. Taking the average change in the average internal event core damage frequency and ratio-ing it twice and saying that it has any relevance to the fire-initiated core damage frequency that's dominated by specific combinations of initiating events and equipment failures just doesn't make any sense at all.

If you had gone through, if you or the licensee had gone through, a systematic evaluation of those top 95 percent scenarios and said, "Okay. If this scenario, fire scenario, is modeled as a loss of off-site power or an MSIV closure and let's look at the change in that kind of contribution and scale it according to the type of event that it looks like," I might have been more convinced.

But to come up with a number that says the change from pre-EPU to post-EPU from the internal fire risk is $1E^{-6}$ has absolutely no basis at all. I have no confidence that that number -- I mean, it could be $5E^{-6}$. It could be $1E^{-8}$. There's just no technical basis for it at all.

And I don't know if that type of analysis or calculation has been done in previous EPU submittals. And I don't have that background, but it should stop now if I could be pretty blunt.

Not only is it not technically justified. It gives the wrong message toe potential future applicants to say that that type of application would be accepted if it were performed.

DR. WALLIS: It's not conservative or anything like that.

MEMBER STETKAR: It's not. It's not.

DR. WALLIS: No.

MEMBER STETKAR: You can't characterize it as approximate or conservative or anything. It's just --

DR. WALLIS: Wrong.

MEMBER STETKAR: It's just wrong.

MR. HARRISON: We will take that comment and go back and fix it.

MEMBER STETKAR: And the same applies also for the couple of scenarios where you did the same type of ratio-ing on the seismic, the ones that didn't just pass through from guaranteed failure, because of the five or six seismic scenarios, you apparently did the same type of numerical ratio-ing if I read the words right.

DR. KRESS: Did you look at shutdown risk?

MR. STUTZKE: It was qualitative.

MR. HARRISON: It is a qualitative approach. It's typical --

DR. KRESS: Normally an increase in power affects the shutdown more than normal risk, doesn't it?

MR. HARRISON: There is the decay heat and issues that would be reflected in shutdown risk that, again, it's done qualitatively by the licensee to address the time extensions that occur and then alternate feed capability gets pushed out. But, again, as I reflected, it's a number of hours later. It's not --

DR. KRESS: It's not some --

MR. HARRISON: It's not near-term.

MEMBER STETKAR: Yes. Typically as long as you don't change fundamental success criteria, like requiring RHR loops early on or something like that, as long as the fundamental hardware success criteria is staying the same, the time windows are typically long enough that the delta in the time usually isn't too relevant.

MR. HARRISON: Well, again, that was done qualitatively. We have always evaluated those. I don't want to say always, but the vast majority of our reviews have always been qualitative reviews in that area.

With that, why don't we jump to the conclusions? The staff concluded that the licensee had accurately modeled. Again, they talked about their self-assessment against the standard as well and that they have addressed the potential risk impacts associated with it.

The majority of their identified impacts in this application are typical of what we see in power uprates that do a 15-20 percent uprate.

The risks are acceptable. They meet what would be our reg guide 1.174 risk acceptance guidelines if it had been risk-informed. And, with that, we conclude that we could not identify any special circumstances that would rebut the presumption of adequate protection provided by meeting the deterministic review criteria.

With that, I'm open to any other questions.

CHAIR ABDEL-KHALIK: Any other questions?

(No response.)

CHAIR ABDEL-KHALIK: Thank you, gentlemen.

Move on to item 22.

22. MATERIALS AND CHEMICAL ENGINEERING

MR. MITCHELL: Good afternoon. I'm Matthew Mitchell, Chief of the Vessels and Internals Integrity Branch in NRR. I'm sitting in this afternoon for my reviewer of the Hope Creek EPU to talk about the specific topic of reactor vessel integrity.

For the benefit of the newer members of the Committee, I will just briefly review the fact that the applicable regulations for a BWR like Hope Creek in the area of reactor vessel integrity are 10 CFR Part 50, appendices G and H.

Appendix G addresses the need to establish reactor pressure vessel, pressure temperature limits, and sets limits for upper shelf energy, for reactor vessel beltline materials. And appendix H addresses the need to establish a reactor pressure vessel material surveillance program monitoring changes and material properties.

I will go right to summarizing the results of our review of the Hope Creek submittal. First is that the reactor pressure vessel surveillance program proposed by the licensee continues to comply with the guidance and structure provided in the BWR vessels and internals project integrated surveillance program, which the licensee is already implementing.

There's a small change to the proposed withdrawal date. I believe it moves from 22 to 23 effective full-power years for the next Hope Creek surveillance capsule. But with that small modification, it would continue to support the licensee's compliance with appendix H.

With regard to pressure temperature limits, the existing Hope Creek pressure temperature limits continue to remain valid. The analysis upon which those P-T limits were set up back in 2004 were actually already incorporated considerations of a future EPU. Hence, we merely confirmed the facts at the adjusted reference temperature for the limiting material remained the same and that, therefore, the P-T limits remained valid.

With regard to the upper shelf energy analysis, both the limiting beltline plate and weld remained above the 50-foot pound screening limit established in appendix G and are, therefore, acceptable.

MR. YODER: All right. I am Matt Yoder from the Chemical Engineering Branch. I'm going to talk about protective coatings for accelerated corrosion, reactor water cleanup system.

I've provided you with the regulatory framework for each of these areas. Unless there is no objection, I will skip over that and go right into the technical review.

Next slide. For protective coatings --

DR. WALLIS: Does pressure uprate have anything to do with coating?

MR. YODER: It doesn't. That's what I'm about to say.

(Laughter.)

MR. YODER: Well, what we're concerned with is the coatings are qualified in an autoclave to withstand temperature pressure and radiation. There is a slight increase of each of those things. The bottom line is that the original qualification still bounds the coatings.

Next slide. Next. For flow-accelerated corrosion, there is an impact. Obviously some components in some systems are going to see an increase in the wear rate. This is due primarily to the velocity.

DR. WALLIS: These are not safety-significant components, are they?

MR. YODER: Some of them are.

DR. WALLIS: Some of them are? Okay. But the wear rates there are very small, aren't they?

MR. YODER: As a result of EPU, I think the most susceptible systems saw between a 10 to 25 percent increase in the wear rate.

DR. WALLIS: That's way up in the feedwater heaters and things like that, isn't it?

MR. YODER: Yes. The most susceptible systems, yes, the feedwater heater drains and sealed steam systems.

CHAIR ABDEL-KHALIK: Please continue.

MR. YODER: Okay. The licensee put in the new parameters for velocity temperature flow into their predictive model, determined what the most susceptible systems would be and, as I said, what the wear rates would be for those systems. As a result of that, some components were added in as additional monitoring points to the existing CHECWORKS model to predict wear rates.

Next.

MEMBER STETKAR: Let me stop you there since it's flow-accelerated corrosion. It might be a PRA question, but somewhere -- and it wasn't the PRA section -- said that they did a sensitivity study to account for the possible effects of flow-accelerated corrosion by doubling the large LOCA initiating event frequency. And by doing that, the core damage frequency increased by 2.3 percent.

Any idea what would happen if you doubled the small LOCA initiating event frequency, what effect that would have on a delta CDF, this sensitivity study to account for the possible risk impacts from increased flow-accelerated corrosion?

MS. KUGLER: Could you repeat the question?

MEMBER STETKAR: Yes. The question was, in a risk assessment, a sensitivity study was performed to look at the potential impact from flow-accelerated corrosion by doubling the large LOCA initiating event frequency. And the result of that increased core damage frequency by a little more than two percent.

The question was, do you have any idea what would the core damage frequency impact be if you doubled not the large LOCA frequency but the small LOCA frequency because flow-accelerated corrosion could indeed affect -- there's no reason to believe it's necessarily going to cause a large LOCA. It could cause a small LOCA.

DR. BURNS: Would you like me to address

that? Ed Burns. Okay.

I would look at the turbine trip frequency change that we did. We doubled the turbine trip frequency. And that came out to be around 1 or 2 times 10^{-6}. That would give you a pretty good idea of what you would do if you --

MEMBER STETKAR: Turbine trip model take credit for feedwater and condensate?

DR. BURNS: Yes.

MEMBER STETKAR: Okay.

DR. BURNS: And we would do that for --

MEMBER STETKAR: For small LOCA.

DR. BURNS: For small LOCA, we would use the condensate system after the MSIVs went closed.

MEMBER STETKAR: And what was the increase?

DR. BURNS: For the doubling of the turbine trip?

MEMBER STETKAR: Yes.

DR. BURNS: It was around one to two times 10^{-6}. So if you go to the small LOCA frequency and double that, you could back that out.

MEMBER STETKAR: Thank you.

DR. BURNS: Sure.

MR. YODER: Okay. Reactor water cleanup

system is the last system I will talk about. There are some changes to the operating temperature and pressure. Those remain within the design limits of the system. And these are what I consider very insignificant changes.

DR. WALLIS: Isn't this the one which gave rise to a bigger mass loss if it broke or something? There was one mysterious place. I think this was the one. What was it? They changed the pipe size.

MEMBER STETKAR: But what we see now, they --

DR. WALLIS: I thought I read that the mass release for breaks on the reactor water cleanup system piping will increase by 36 percent. I didn't understand that.

MR. DUKE: This is Paul Duke.

That's correct. Actually, the increase is due to the change in conditions at the break location. We changed our conditions for evaluation to assume that the break would occur at the MELLLA minimum flow point.

So you would have actually higher break flow just by virtue of the fact that you had additional subcooling at the break location. That applies with or without EPU.

DR. WALLIS: Right. This is not an EPU effect.

MR. DUKE: That's correct, but it was reevaluated for EPU.

DR. WALLIS: Thank you.

MR. YODER: The other impact of EPU is that you will have additional impurities, principally iron, coming in from the feedwater that the reactor water cleanup system will have to handle. And, again, that remains within the system's capabilities.

CHAIR ABDEL-KHALIK: I think the applicant indicated that the reactor vessel at Hope Creek is the only Hitachi vessel amongst the BWR fleet. Has that presented any special or unique questions in your review of the reactor vessel?

MR. MITCHELL: The answer to your first statement is that's correct. I do believe Hope Creek owns the only Hitachi vessel, but no. In general, the materials from which reactor vessels have been fabricated for the entire fleet, not only the B's, but the PWRs are very similar in terms of the material specifications.

So they are very common and very comparable, although they may have been manufactured by different vendors: Chicago Bridge and Iron, Combustion Engineering, Hitachi. The material specs are always very close to one another.

So the information we have gotten from multiple vessels is comparable from one to the other.

DR. WALLIS: So the other like PWR vessel heads, there seems to be quite a variation, susceptibility?

MR. MITCHELL: No, not on the items that are of principal interest from an RPV integrity standpoint on initial RTNDT copper nickel. They're well-defined.

MEMBER MAYNARD: I meant to ask this when the applicant was up there. I'm not for sure it is more appropriate for staff or the applicant. That's the only one in the U.S., but are there Hitachi vessels outside the U.S.? And are you getting any operating experience or information relative to those if they are?

MR. DAVISON: This is Paul Davison. The answer is yes. There are other Hitachi vessels overseas, outside the United States. They are not part of the ISP program, however. So the operational experience that we get from them does not come through that channel, however, does exist. And we do ensure that we incorporate operating experience in our program.

MEMBER MAYNARD: Okay.

DR. WALLIS: GE and Hitachi are not together. So you could get information through --

MEMBER MAYNARD: I meant to clarify that earlier because you talked about them not being in the program, but that doesn't mean the data that -- that's good.

CHAIR ABDEL-KHALIK: Thank you. We'll move on to item 23, presentation by the applicant on electrical and grid reliability. And I promise that we'll take a break after that presentation.

DR. WALLIS: We are almost at the end, aren't we?

23. ELECTRICAL AND GRID RELIABILITY

MR. DAVISON: Good afternoon. I am Paul Davison. With me is Brandon Swarley from the Hope Creek Electrical Design Group. And we will be discuss the electrical and grid reliability on page 41.

Hope Creek operates in the Pennsylvania, New Jersey, Maryland, or PJM, interconnection territory. As required by PJM, Hope Creek filed the Federal Energy Regulatory Commission, or FERC, approved regional transmission expansion planning process and performed studies in accordance with the

FERC-docketed interconnection service agreement for the power uprate and its effect on the grid.

Feasibility was conducted and included short-circuit end flow analysis. And the system impact included a comprehensive regional analysis that included stability assessments for single and multiple facility contingencies.

Finally, the generation interconnection facility study was performed to assess detailed artificial island operating strategies. The studies are docketed in the RTEP, or regional transmission expansion planning, keys, H18 and H19, and serve as input to that living database for other active transmission and generation studies. This prevents invalidation of our studies while we await implementation of EPU.

Next slide. All studies showed that there were no problems at EPU conditions with the exception of the system impact study, which violated the Mid-Atlantic Area Council criteria number IV. The study revealed that a single line to ground fault on the red line 500 kV line at Hope Creek where the number 3-4 breaker does not trip, would result in Salem-Hope Creek units becoming unstable and potentially tripping.

DR. WALLIS: This has nothing to do with EPU, does it? This has nothing to do with EPU?

MR. DAVISON: Increased power output of the station.

DR. WALLIS: It causes this to be unstable?

MR. DAVISON: Yes.

DR. WALLIS: It wasn't unstable before.

MR. SWARLEY: Increased inertia on the machine.

DR. WALLIS: Enough to make it unstable?

MR. SWARLEY: Increased output in the system model changes, too, into the configuration.

DR. WALLIS: What sort of a system model is this?

MR. SWARLEY: It is a transient stability model. So this is a model in the PSSA program by PTI.

DR. WALLIS: It's not your own model?

MR. SWARLEY: No. This is owned by the regional transmission company, PJM. It's actually a model developed by all the members and input to PJM. PJM uses this for the 1,200 and some generating sources they have within their area.

DR. WALLIS: Do you input your own plant models?

MR. SWARLEY: Yes.

DR. WALLIS: It takes into account inertia and things like that?

MR. SWARLEY: Yes. And we provide them --

DR. WALLIS: So this red-line effect has nothing to do with the red-line effect which is in my book?

MR. DAVISON: LIN.

DR. WALLIS: Oh, I'm sure it doesn't. You won't understand the reference.

MEMBER SIEBER: It seems to me as this is not an EPU issue. To me it is written out on the slide as a current issue.

CHAIR ABDEL-KHALIK: A current issue?

MEMBER SIEBER: Yes. You have a stuck breaker 60X, that's the stability issue is there, whether you increase the plant output or not, right?

MR. SWARLEY: By increasing the plant output put us closer to the stability limits.

MR. DAVISON: The question is, if we were to have the fault today before EPU, would this same condition requiring a break or addition be present?

DR. WALLIS: And the question I asked as well?

MEMBER ARMIJO: Yes.

MR. SWARLEY: Since we have increased the machine inertia or changed that inertia, now that we have our extra breaker in the system, we wouldn't have that situation now.

MEMBER SIEBER: Yes. This will solve the problem. Well, we are reviewing EPU, not today's operations.

MEMBER MAYNARD: It is potentially an EPU. It really depends on, did this increase in power put you over the margin there, too much of the margin? I think you were initially saying, yes, it did.

I'm not getting a high level of confidence that that's the case. I think this takes care of the problem either way, but --

DR. WALLIS: The answer to Jack's question is different from the answer to mine. Then I am confused.

MR. SWARLEY: The stability case analyzed for EPU is we increased the machine output significantly. We went up to 1320 for our EPU model for the PJM. We also changed our machine inertia.

When they redid the study, they looked at many different fault scenarios. And they came up with one where they said if we have a single line to ground with a stuck breaker, we should include this new breaker.

MEMBER MAYNARD: I understand that for the EPU conditions. That same analysis at current license level conditions, would you still be exceeding that, getting into the stability issues?

DR. WALLIS: The inertia doesn't show.

MR. SWARLEY: I don't believe so because we would be operating at a lower power. And the power has to do with coming closer to the stability limit.

MEMBER SIEBER: The real key question is, when do you plan to change or add the circuit breaker?

MR. DAVISON: That was already done several years ago.

On page 43, there is a schematic pictorial of our previous discussion. The 62X breaker that is depicted in red is located between the 60X and the number 2 bus. So the single phase line to ground fault is shown also in red.

This fault in conjunction with the delayed breaker trip of the 60X would result in that Mach criteria IV violation, hence the addition of that 62X breaker that was done several years ago.

Page 44. The artificial island operating guide for EPU and exists now covers various operating scenarios, which operations follow for dispatch decisions. They include multiple unit operating combinations; Salem-Hope Creek power system stabilizers being in or out of service, which is associated with more precise generator voltage regulation; and the Salem trip-a-unit scheme, enabled or disabled, that results in the trip of a Salem unit during transmission line loss.

The purpose of the operating guide is to ensure that minimum required reactive power is available to maintain grid stability following the analyzed contingency implementation via a real-time analysis tool. The real-time analysis also enjoys its situations that could result in off-site source inoperability for the GDC requirements are communicated to operations personnel to take appropriate action.

On page 45, in conclusion, the increased power output attributed to the Hope Creek EPU was assessed in accordance with the PJM planning process to ensure that the grid stability and station off-site power source reliability remains at all times.

End of presentation. If you have any questions?

CHAIR ABDEL-KHALIK: Any questions for Mr. Davison?

MEMBER BANERJEE: Did the staff have to review this or they are going to come back to us, right?

CHAIR ABDEL-KHALIK: Yes, yes. Thank you.

MR. DAVISON: Thank you.

CHAIR ABDEL-KHALIK: At this time we will take a break, 15 minutes. We will be back at 4:35.

(Whereupon, the foregoing matter went off the record at 4:18 p.m. and went back on the record at 4:32 p.m.)

CHAIR ABDEL-KHALIK: We are back in session. Before we get started with presentation number 24, the applicant would like to provide some information regarding information that had been requested earlier.

MR. DAVISON: Yes. Thank you. Paul Davison from PSEG.

I have two follow-up items from earlier conversations. During my discussion on vessel internals, I was talking about the jet pump sensing lines, the finite element analysis, and the hammer testing that we did. The question was, what were the natural frequencies of the sensing lines inside the vessel?

There are two modes: one at 50 hertz,

approximately 50 hertz; and the second at 150 hertz. In fact, the reason for the clamp that was installed on jet pump sensing line number 11 was due to its natural resonance frequency being very close to the vane base frequency of the reactor research pump.

Second follow-up is to several questions associated with the moisture carryover testing. I will take them one at a time. There was a question regarding the sodium source. That's naturally occurring in our groundwater, sodium-23. Our demineralized water plant removes most but not all of the sodium-23. Therefore, the sodium-23 is changed into sodium-24 in the reactor.

Sodium-24 has a half-life of approximately 15 hours. It is only carried over in the water content of the steam flow. Therefore, there is a --

DR. WALLIS: Excuse me. Fifteen-hour half-life? How does it exist? It must be formed on something else all the time.

MR. DAVISON: Continuous, correct.

DR. WALLIS: If it ever just existed by itself, it would --

MEMBER BANERJEE: The cross-section isn't that high.

MR. DAVISON: Correct.

DR. WALLIS: But you say it came in your groundwater?

MR. DAVISON: Correct, our water that we use to make demin.

DR. WALLIS: And the groundwater is making it all the time?

MR. DAVISON: Correct.

DR. WALLIS: What's making it? Leakage from the plant? You're leaking stuff into the ground and then using it in your groundwater as a tracer?

MR. DAVISON: No, no.

(Laughter.)

MR. DAVISON: We've done tritium testing.

DR. WALLIS: It has a 15-hour half-life. So the only reason it exists is if it is made from something else with a much longer half-life.

MEMBER BANERJEE: Sodium-23.

DR. WALLIS: So it must be made from something with a much longer half-life.

MEMBER BANERJEE: Sodium-23.

DR. WALLIS: It has a much longer half-life. That's why it's there. I'm sorry. I didn't hear it. So sodium-23. Okay.

MR. DAVISON: Okay. So our actual testing that we do on this is between the reactor water, comparing the content between the reactor water and the actual water in the condenser.

So we do take samples from the reactor, be it reactor water cleanup system, as well as the condenser hotwell via the condensate demineralizer inlet or influent and do radiochemistry testing on it.

As far as how do we compare to the industry, we are very similar to plants like Peach Bottom and Clinton that un in the .003 to .005 range. We are lower than other plants --

DR. WALLIS: So that is percent? That is percent?

MR. DAVISON: Percent. We are lower than other stations, like Limerick, Dresden, LaSalle and Quad Cities, that run in the .01 to .05 percent range and much lower than Oyster Creek that is at .1643 percent, just to give you a range of the different sets of plants that are out there.

DR. WALLIS: And then you said that you would stop if it went up by 50 percent in your ascension? Is that right?

MR. DAVISON: Okay. With respect to our predictions, our prediction is .03 at EPU. This is based on some initial GE analysis and factoring in the six-fold increase that we have seen at a plant like

Vermont Yankee.

DR. WALLIS: It goes up by a factor of six just for that power increase.

MR. DAVISON: Well, that is our estimate. However, because our moisture carryover is so low and there is such a wide variation in the industry data, we continue to use the .1 as our level II, which is our stop-and-analyze.

DR. WALLIS: Well, you make it something which is a little difficult to interpret. I mean, you may find that it goes up to .06 or something like that. And you say, "Well, we didn't expect it to up so much, but it's still less than .1. What should we do?"

MR. DAVISON: Correct. And that is the value of the trending that we're going to be using that with because we can take the trend of moisture carryover with respect to our power increase --

DR. WALLIS: Right.

MR. DAVISON: -- and use that to compare it with the changes we're seeing in the main steam line accelerometers and also the main steam line strain gages. So we have three different sets of data or ways to look at it to make a determination or evaluation if there is an adverse trend or something that is not understood.

DR. WALLIS: The trend is steeper than you thought as well. Yes.

MR. DAVISON: Correct.

CHAIR ABDEL-KHALIK: Your level II for this says, "Moisture carryover exceeds .1 percent" --

MR. DAVISON: That is correct.

CHAIR ABDEL-KHALIK: -- or "Moisture carryover exceeds .1 percent and increases by greater than 50 percent over the average of the 3 previous measurements taken at greater than," et cetera.

Isn't one a subset of the other?

MR. DAVISON: Well, the reason if we exceed .1 and we understand and analyze that to be acceptable, we don't want to have no other acceptance criteria before we meet the level I or the .3 percent. So what we then say is if we're above .1, we're going to be looking for that 50 percent change that you mentioned.

DR. WALLIS: You have to get above .1 first?

MR. DAVISON: That is correct. First is .1. And then after that, it would be 50 percent changes that would be triggering.

DR. WALLIS: From .005 to .1. That's

pretty significant by itself.

MR. DAVISON: Correct. And that would be analyzed and compared to the other two data sets that I mentioned.

DR. WALLIS: Thank you.

MR. DAVISON: Thank you.

CHAIR ABDEL-KHALIK: There was a third question regarding the uncertainty.

MR. DAVISON: Yes. Thank you. I am sorry.

The average value, our calculation via the radiolytical testing, radiochemistry testing is .005871. We have a standard deviation of .001233 for significant digits.

But the gamma spectroscopy values are plus or minus 30 percent based on our analytical data in our chemistry lab on site. And that's done in accordance with GE SIL-644 recommendations.

DR. WALLIS: Ever due to just not having enough sample, statistical thing or is it something else?

MEMBER BANERJEE: It must be a counterage issue, right?

DR. WALLIS: The counter?

MEMBER BANERJEE: It's germanium crystal, I take it, right?

MR. DAVISON: I don't know what type it is. That was the accuracy provided by our Chemistry Department with respect to our --

DR. WALLIS: You would have to have a big enough sample to get anything significant. Count forever.

CHAIR ABDEL-KHALIK: We will now proceed with the staff's presentation, item number 24.

24. ELECTRICAL AND I & C

MR. McCONNELL: Good afternoon. My name is Matthew McConnell. I am an electrical engineer in NRR. My branch was tasked with reviewing the electrical systems portion of the Hope Creek generating station's power uprate request. And I was one of the principal reviewers of that application. Sheila Ray, to my right, was also a reviewer.

Next slide. We reviewed the uprate application against regulations governing environmental qualifications, station blackout, and electrical power systems. Specifically, we reviewed the application to ensure that the existing environmental qualification classifications remain valid, that the loading on the safety equipment will remain bonding and that Hope Creek generating station would continually operate safely under increased electrical output and increased plant load.

We also reviewed the results of the grid stability study that was provided in the Hope Creek power uprate application. PJM, the regional transmission organization for Hope Creek generating station performed the grid stability study for the proposed power uprate.

After reviewing the grid stability study results, we found that the grid stability study demonstrated that the power system and stable for all three phase and single phase failed study and, two, under all power flow conditions tested that the station and transmission systems satisfied the regional coordinator's reliability principals and standards; three, the tripping of the Hope Creek generating station will not have detrimental effects on grid stability; and, finally, that the artificial island bus remains stable and available.

Next slide, please. Licensee identified multiple components that would be impacted by the proposed power uprate. The licensee addressed these items by either upgrading or replacing these systems and/or components.

Specifically, the licensee made the

following modifications to support operation at power uprate conditions. The licensee divided the iso-phase bus stack into sections of modified bus stack cooling to remove the bus duct heat. Furthermore, the licensee added new main bank transformers and upgraded the main generator stator cooling.

Licensee also added a new 500 kV, I as mentioned earlier, breaker to provide backup clearing in the event of a stuck breaker. Licensee contended and the staff concurred that this would improve system stability. Finally, the staff verified that the existing protective relaying remained adequate.

Based on our review, we found that the Hope Creek generating station will continue to meet the regulations for environmental qualifications, station blackout, and electrical power systems while operating at power uprate conditions.

That concludes my presentation.

MEMBER STETKAR: Unfortunately, I have to ask you a question. DC systems, in the discussion of the DC systems, the observation was made that EPU conditions would not increase any equipment's duty cycle.

I know analyses were done to show that, for example, depending on the type of transient, you could get something on the order of 13 percent more SRV cycles.

I asked the question earlier and didn't get an answer about number of HPIC and RCIC cycles. Those changes, if, indeed, there are additional HPIC/RCIC cycles would seem to impose additional loads on the station batteries. Did you look at that?

MR. McCONNELL: No, we did not.

MEMBER STETKAR: Why?

MR. McCONNELL: Because part of our application or review was centered around the fact that they had no increased loading expectations and did not provide any additional information to allude to the fact that there would be any additional loads on the DC system.

MEMBER SIEBER: There aren't, but there is capacity difference.

MR. McCONNELL: Absolutely. There would be a capacity difference if you were to --

MEMBER STETKAR: Well, yes. And the statement was made there wouldn't be any more duty cycles, which would affect capacity.

MR. McCONNELL: Well, duty cycle. Let's go back and refer, the duty cycle, where the battery is when you are recovering the overall load of the duty cycle, which would actually be something that would be testing on a normal basis through your service discharge test, which is a typical test. But it doesn't necessarily represent how many cycles the batteries --

MEMBER STETKAR: Ampere-hours are ampere-hours.

MR. McCONNELL: Right.

MEMBER STETKAR: And if you draw more amps from a battery, you have less power.

MR. McCONNELL: Absolutely.

MEMBER STETKAR: And starting equipment draws more amps.

MR. McCONNELL: Right.

MEMBER STETKAR: Starting more equipment more frequently draws more amps, which is more ampere-hours load.

MR. McCONNELL: Right.

MEMBER STETKAR: So my question is, did you look at the effects of increased loading on the battery due to increased numbers of DC-operated pieces of equipment, specifically HPIC/RCIC.

And perhaps if I could ask the licensee, are HPIC and RCIC the DC taken from the station batteries here or do they have a separate battery at

Hope Creek? Anybody? One or the other?

MR. SWARLEY: Hi. I'm Brandon Swarley from Hope Creek.

HPIC and RCIC both have their own battery systems, 2 50-volt battery systems for each one.

MEMBER STETKAR: Okay. Good. Thank you.

MR. SWARLEY: You're welcome.

MEMBER STETKAR: So the only change, significant change in loading, might be the additional SRV cycles.

MEMBER SIEBER: Solenoid balance?

MEMBER STETKAR: Yes, it would be solenoid balance. Those are small. Those are small compared -- thank you. I'm satisfied.

MR. McCONNELL: I misunderstood the second part of your question.

MR. GARG: I am Hukam Garg. And I am the senior electrical engineering in the Instrumentation and Controls Branch in NRR. I am the presenter on instrumentation and controls. It is straightforward to review.

All the licensing basis from the previous parts do stay the same except to account for the changes in the system. And those changes result in some changes, which are not too many. There is a bias that we have to take and main steam isolation while on high steam flow. Those are the setpoint changes.

Many instruments have to be re-spanned because of the change in the system's role or system conditions. You have to re-calibrate existing instruments to have the same rhythm. And some of the instruments have to be replaced.

MEMBER BANERJEE: Only APRM or also the OPRMs change using the setpoints?

MR. GARG: Well, PRA needs a setpoint review by itself. I mean, if they want to install it, they can install it. But at this time, I think they are OPRM.

MR. DAVISON: Yes. Paul Davison. The OPRM setpoints will still need to be changed. APRM and also the main steam on high flow are mentioned, but OPRMs, yes.

MR. GARG: It wasn't submitted with the application, right?

MR. DUKE: This is Paul Duke. That is correct. OPRM setpoints are not submitted. They are controlled by the core operating limits report. So they are changed on a cycle basis under licensee control.

MR. GARG: The license has used the

NRC-approved setpoint methodology, which was the setpoint. And we had issued this composite 2006-17 based on we had a problem with some of the matters which have been used.

And we reviewed those setpoint changes on those two documents. And we determined that they continue to mete their licensing basis.

The next slide is --

MEMBER BANERJEE: Did you review the ultrasonic flow sensor measurements? For which instruments are these existing instruments we're talking about?

MR. GARG: Yes. It changes based on the system requirements. If they have a concern, they must have installed it before. And there is no change because of the EPU.

MEMBER BANERJEE: Well, it is being exercised at a higher flow rate, correct?

MR. GARG: Yes, but that is not going to change in there.

MEMBER BANERJEE: Why not?

PARTICIPANT: If it's within range.

MR. GARG: Yes.

PARTICIPANT: If it's out of range, you've got a problem.

MR. GARG: But, you know, since they are different and if it is still in the range and they did not make any change to --

MEMBER BANERJEE: Well, at these higher flow rates, wouldn't they need to validate the calibration of the --

MR. GARG: Well, they will calibrate all the instruments based on the flow. And, you know, if they will go through the proper sensing, they are going to deliver every day. The instruments need to be calibrated every refueling cycle. So they are going to go through the recalibrations and all of those, whether they go through EPU or not.

MEMBER BANERJEE: So you didn't determine whether these instruments, which are fairly critical, I suppose, will maintain their accuracy after the EPU?

MR. GARG: I mean, there is no way we can determine. I think the licensee come and make that determination based on their system analysis and --

MEMBER BANERJEE: Did they submit any analysis to show that these instruments will retain their accuracy? Is that something which is sort of -- I don't know. Is it routinely taken care of or the end, that's what you do? These measurements will remain accurate?

MR. DUKE: This is Paul Duke. Are we talking specifically about ultrasonic flow measurement?

MEMBER BANERJEE: Right.

MR. HARRISON: We do. Yes, that is going to be calibrated. I want to ask Paul Davison and describe what we are going to do. We're not going to rely on it any longer, but there are plans to recalibrate it.

MR. DAVISON: Yes. I had mentioned before we have recalibrated coming out of the refuel outage by statistical comparison to others. On the chart that I showed you with all of our testing, you see that each of the final power levels, the 111 and a half and then 111 and a half with cross-flow.

The reason they are broken out separately is because there's much data to be collected in doing that comparison again so we can verify its accurate before we would implement that correct factor to the venturis and then go up to the 111.5 or eventually the 115.

MEMBER BANERJEE: If I remember, you said there were three separate measurements which you would then check for consistency against --

MR. DAVISON: Correct. Normally the AMAC

system is installed on our common header. To do the checks, we put individual ultrasonics on each of the three feedwater lines coming from the individual feed loops, Alpha, Bravo, and Charlie, A, B, C, and use that data.

We also compare it to the venturi, of course, to make sure that the expected deviation is within the band. And we have secondary means, such as turbine first stage pressure, that we also use all to make sure that we don't end up in an over-power condition

MEMBER SIEBER: These are infinite ultrasonics or terminate ones?

MR. GARG: These are permanent.

MR. DAVISON: Paul Davison.

Permanent installed.

MR. GARG: Next diagram is a standard for any plant. So I don't know if that is how you do the calculations. It's for information.

CHAIR ABDEL-KHALIK: This is your presentation, sir.

MR. GARG: I mean, unless there is a need to, I mean, I will go over it depending on the timing, I mean, if you -- I can go over the diagram. There is the instrument, the analysis and the safety limit.

From there, to account for the uncertainty in the modeling and all of that, you determine the analytical limit. And from there take out the total loop uncertainty, whatever the instrument is going to have, and determine the limiting trip setpoint.

The instrument is normally set at the lower than the limiting setpoint to allow for additional margin. And it will be the nominal setpoint. But they could set anywhere between the nominal setpoint and limiting setpoint.

RIS 2006-17 puts some additional requirements, which is the acceptable as found tolerance and acceptable as left tolerance. As left tolerance is the limit where when you reset the instrument, it has to be reset within that limit. So they could assure you that it's not going to exceed the total loop uncertainty and you are not going to like the safety limit.

And the as found tolerance during any service, that is how much the instrument is going to -- should be grown. And if it is beyond that, then that would take some corrective actions and has to relay it, whether the instrument is equivalent or not. And they have to reset it.

And that's pretty much all I had to say on that.

DR. WALLIS: What is this arrow that says, "Direction of increasing conservatism"?

MEMBER ARMIJO: I don't understand.

DR. WALLIS: Presumably as you go --

MEMBER ARMIJO: It goes the other way.

DR. WALLIS: It goes the other way.

MEMBER ARMIJO: That's the way --

DR. WALLIS: Does it go the other way?

MR. GARG: I agree.

DR. WALLIS: Does it go the other way?

MR. GARG: It should go the other way.

DR. WALLIS: Does this just make me suspicious of everything else you say on this graph?

MR. GARG: No, no.

(Laughter.)

MEMBER ARMIJO: It shows that we're on our toes.

MEMBER MAYNARD: Even at 5:00 o'clock.

CHAIR ABDEL-KHALIK: Well, thank you.

Next we'll move to the last staff presentation.

25. SOURCE TERMS AND RADIOLOGICAL CONSEQUENCES

MS. DUVIGNEAUD: Good afternoon. My name is DyLanne Duvigneaud. I am a reactor engineer in the

Accident Dose Branch in NRR. And today I will be speaking to you about the source terms and radiological consequences analyses for the Hope Creek extended power uprate.

In reviewing the Hope Creek EPU source terms for radwaste systems analysis, the NRC staff used matrix 9, section 2.9.1 of the review standard for extended power uprates. The radiation sources and the reactor coolant were analyzed for constant pressure power uprate conditions.

The NRC staff has reviewed the radioactive source term and reactor coolant and steam associated with the proposed EPU and concludes that the proposed radioactive source term meets the requirements of 10 CFR Part 20, Part 50, appendix I, and GDC-60.

DR. WALLIS: Can I ask you something?

MS. DUVIGNEAUD: Yes.

DR. WALLIS: Maybe you're going to get to it. On the SER, it says, "The annual public dose from the plant gaseous effluents, 1.83 times 10^{-3} millirem." That comes out to 1.8 microrem. Is that really what you mean, microrem, or has another factor of 1,000 been added by mistake?

MS. DUVIGNEAUD: Can you repeat that? I'm sorry.

DR. WALLIS: Pardon?

MS. DUVIGNEAUD: Can you repeat that for me? I'm sorry.

DR. WALLIS: On page 203 of the SER, it says that "The annual public dose from the plant gaseous effluents is 1.83 times 10^{-3} millirem," which to me means 1.83 microrem. It seems to me that maybe another factor of 1,000 has been added. Maybe the applicant has a comment on that.

MR. PATEL: My name is Gopar Patel from Nucor Consulting.

This number is true because this information is derived from our computers.

DR. WALLIS: So the number is micro?

MR. PATEL: Yes, sir, 10^{-3} millirems. Yes.

DR. WALLIS: Okay. Should be there?

MR. PATEL: Yes. Thank you.

MEMBER BANERJEE: This is much better than a coal plant.

(Laughter.)

DR. WALLIS: Okay. Thank you.

MS. DUVIGNEAUD: Okay. In reviewing the Hope Creek EPU design basis accident radiological consequences analyses, the NRC staff used matrix 9, section 2.9.2 of the review standard for EPUs.

The NRC staff approved implementation of an alternate source term for Hope Creek on October 3rd, 2001. That AST analyzed Hope Creek's DBA radiological consequences for its current license power of 3,339 megawatts thermal.

Because the previously analyzed power is lower than the proposed EPU power level of 3,840 megawatts thermal, the licensee reanalyzed Hope Creek's DBA radiological consequences. The analyses follow regulatory guide 1.183.

The NRC staff concluded that all reanalyzed DBAs meet 10 CFR 50.67 and SRP 15.0.1 dose acceptance criteria, both off-site and in the control room.

Revised DBA dose analyses were submitted in support of the proposed EPU for the following accidents: loss of coolant, main steam line break, fuel handling, control rod drop, and instrument line pipe break.

As part of this review, the NRC staff confirmed that the assumed control room unfiltered inleakage is supported by tracer gas testing. For each of the revised DBAs. the NRC staff performed confirmatory calculations when deemed necessary?

DR. WALLIS: Can I ask you about the fuel-handling accident? The assumption seems to be that you drop a fuel assembly. And you generate 124 rods. Where does the 124 rods come from? Is it something in the regulations? Something in the regulations, is it?

MS. DUVIGNEAUD: No.

MR. PATEL: This is Gopar Patel here.

This 124 rod assembly damage is given by GE analysis. So this is input from GE. And we use in our analysis.

MEMBER ARMIJO: You are dropping an assembly on another assembly?

MR. PATEL: Yes. I think we dropped the assemblies on the coal. And that's damages on the stored fuel assembly, spent fuel assembly in the pool. And some of the assembly from the dropping, dropping material is also damaged. The total is 124 rods.

MEMBER ARMIJO: I don't know where they came up with that number because it is a strange number.

DR. WALLIS: It is a strange number, yes.

MEMBER BANERJEE: We must have done some analysis when using a rod.

MEMBER ARMIJO: It's probably before my

time.

DR. WALLIS: Is this something that's supposed to be conservative?

MS. DUVIGNEAUD: Yes.

DR. WALLIS: Is it?

MS. DUVIGNEAUD: The licensee has adequately accounted for the effects of the proposed EPU. All DBAs meet 10 CFR 50.67 and SRP 15.0.1 dose acceptance criteria for both off site and in the control room.

The staff concludes that the Hope Creek plant site and of those mitigating ESFs remain acceptable with respect to the radiological consequences of the postulated DBAs.

Therefore, the staff finds that the licensee's proposed EPU is acceptable with respect to the radiological consequences of DBAs.

This concludes my presentation. Are there any questions?

CHAIR ABDEL-KHALIK: Are there any questions?

MEMBER BANERJEE: Does the licensee store planned or is already storing, doing dry storage of the source?

MR. DAVISON: Paul Davison.

Yes, we do have interim spent fuel storage on site outside in external casks.

MEMBER BANERJEE: And EPU will increase the rate at which you will keep this secure somewhat. I mean, will you have more storage casks, things like this?

MEMBER ARMIJO: To make energy, you need bundles.

MEMBER BANERJEE: I know.

MR. NOTIGAN: This is Don Notigan, PSEG.

The EPU will not have a direct effect on the dry cask storage because the cask needs a certain decay time on the fuel before it goes in.

MEMBER BANERJEE: So I missed that.

MR. NOTIGAN: The casks require a certain decay time in the pool before they can put in a cask. So implementing EPU does not increase that right away.

MEMBER ARMIJO: But the discharge fuel will be forcing the older stuff out of the pool.

MR. NOTIGAN: Correct.

MEMBER ARMIJO: You don't have room.

MR. NOTIGAN: We have adequate room.

MEMBER ARMIJO: But it still cannot go out until it meets the requirements there.

MEMBER BANERJEE: But eventually you will have to have more new stuff. You are putting more fuel in or are you talking it to a higher burnup, which I don't know, or more even burnup?

MR. NOTIGAN: This is Don.

We have already evaluated the dry cask storage requirements. We are not increasing the number of casks we would need from the original design. The batch sizes are not increasing that large.

MEMBER BANERJEE: How are you doing that? Is it just you are holding it up longer or --

MR. NOTIGAN: The HoldTech casks require a certain decay time in the fuel pool --

MEMBER BANERJEE: Right.

MR. NOTIGAN: -- before they can be placed in the casks.

MEMBER BANERJEE: Right.

MR. NOTIGAN: That decay time does not accelerate because of EPU.

MEMBER BANERJEE: That decay time doesn't. So in order to make this power, you have to burn more fuel, correct, or take the fuel to a higher average burnup, one or the other? If you keep the burnup constant, you're going to have --

DR. WALLIS: You have to be burning it

faster to get more power.

MEMBER BANERJEE: Yes.

MR. NOTIGAN: For long-term storage and multi-cycle studies for Hope Creek, we have determined the number of casks we need long term.

MEMBER BANERJEE: I'm just trying to understand why.

MEMBER ARMIJO: You must make some assumption of by which time the Department of Energy will finally take the fuel.

(Laughter.)

MEMBER BANERJEE: So I guess I am trying to understand why you don't need more storage casks. As you are producing more power, you are either taking the fuel at a higher average burnup or you are going to --

MR. NOTIGAN: Yes. The design of the ISFSI includes the storage pad as well as the casks. We have a large capacity for additional casks.

MEMBER BANERJEE: Oh, but you'll have additional casks, correct?

MR. NOTIGAN: We have a long-term contract to bring additional casks if needed.

MEMBER BANERJEE: Right.

MEMBER ARMIJO: So they planned ahead.

MR. DAVISON: This is Paul --

CHAIR ABDEL-KHALIK: How many bundles are you going to change every outage at the EPU compared to how many bundles you are replacing every outage as --

MR. NOTIGAN: Just as a rough comparison, the additional fuel for cycle 15 was 216. As we go forward with our multi-cycle analyses, we are only increasing that by 20 assemblies, equilibrium.

MEMBER BANERJEE: So ten percent more?

MR. NOTIGAN: Yes.

MEMBER BANERJEE: Ten percent more. That's the answer.

CHAIR ABDEL-KHALIK: Thank you.

26. PUBLIC COMMENTS

CHAIR ABDEL-KHALIK: At this time the agenda calls for solicitation of public comments. Are there any members of the public who wish to make comments?

(No response.)

CHAIR ABDEL-KHALIK: Hearing none, we will move on to the next item, which is Committee concluding comments.

28. COMMITTEE CONCLUDING COMMENTS

CHAIR ABDEL-KHALIK: At this time we will sort of just go around and see if different members have their main comments, summarize their comments and impressions, et cetera.

But before we end the meeting, we would like to be able to provide feedback to both the applicant and the staff as to how they should proceed with regard to the presentation to the full Committee. Presentation to the full Committee is scheduled for Thursday, April 10th. And it's scheduled for 2 hours and 45 minutes.

So at this time Dr. Banerjee?

MEMBER BANERJEE: I think I probably said more than enough in this. The only real concern I have, which I think the applicant and the staff have probably addressed adequately, is related to the steam dryer.

And the thing that reassures me here is that this is a pretty quiet plant, at least from all of the indications that we have, though we haven't seen the comparisons with Vermont Yankee.

The only guidance again that I could give the staff here is that the story supporting this has to be made more coherent. And it must, in some way, close the loop between these measures which have been made in the steam lines and what we expect to happen to the steam dryer.

The concerns I have are more of a generic nature and shouldn't really be a burden on this applicant, but I think the staff should take seriously trying to go from these steam line measurements to what is happening to the streams in the dryer, at least of the measured systems, like Quad Cities and later on Susquehanna. And they need to close that loop in some form of analysis, which they used, which can be used as confirmatory analysis. So this thing doesn't keep raising its head each time we go into it. That's my main comment.

CHAIR ABDEL-KHALIK: Dr. Pierce?

DR. PIERCE: Just as an ordinary person, I am impressed that they have a quiet plant. And I would think my gut feeling is that they wouldn't have any problems with EPU. However, I am here as an expert on acoustics.

And I guess I might do it. And I have lots of questions about the acoustics which I would like to settle for myself. And I learned a lot in this meeting. I think that what CDI has is innovative and very clever, but I would like to look at more thoroughly. And what I will do is try to put these things in writing in a report to this Committee.

I don't know if I can make it by April 10th, but I presume this is going to be a problem that is going to be going on for a long time. So maybe somebody else should look at it. I guess I am the guy.

CHAIR ABDEL-KHALIK: In order for your comments to have an impact on the Committee's deliberations, we have to receive them before --

DR. PIERCE: I realize that. However, I am guessing that this will not be the first or the last meeting of this type I will have and that steam dryers are going to be a problem for a while.

CHAIR ABDEL-KHALIK: Thank you.

Dr. Armijo?

MEMBER ARMIJO: Yes. I would like to comment on the fuels and then also the materials parts of the presentation. I think the fuel presentation is clear that the plants, the core has been designed very conservatively.

And I think partly they might make their presentation a little bit easier on the full Committee if they just show the actual core map where they have got a 216 SVEA assemblies, but based on the enrichment, the burnup, and the loading of those assemblies, I am sure they are putting out far less than 28 percent of the core thermal power the way they are loaded.

That would help get across to other Committee members that this is really very conservatively designed. And so the issues related to applicability of GE methods to the SVEA fuel would be not very hard to sell. I don't see any problems with the fuel.

I think the presentation on plant materials and water chemistry and all the things that the licensee is doing to protect the plant materials is right on target, particularly paying very good attention to their hydrogen water chemistry and noble metal additions. So I think that that will -- you know, all of this has to be a bridge, but I think that will be very good.

And then an area that I don't know anything about -- and that's the dryer and these acoustics -- I guess I would start with showing these limit curves and explain how you got there and how you are going to use them without -- there's no way that the full Committee can possibly go through an understanding of how this was developed. I just think it's just too long.

CHAIR ABDEL-KHALIK: Thank you.

Dr. Wallis?

DR. WALLIS: Well, when I was coming down here, I thought that my report would be that Hope Creek made a very credible and open and persuasive presentation. And so did the staff. And everything is okay.

I think that Hope Creek did make a very good presentation. And but I do feel like I probably have to write something about the dryer.

And if I were to go back over all those CDI reports that I looked at and comment on all of them, I would write a book. That wouldn't really help the full Committee at all.

So I would hope that by the time this gets to the full Committee, that what Sanjoy Banerjee is looking for will happen, that someone can make very clear the link between what is measured in the steam line, what is predicted in the steam dryer, and what has been measured in various steam dryers, and show how this validates an approach which is believable and reliable and can form the basis for our decision-making.

That's what I wanted to see. And, really, I have to restrain myself about writing a text about the various other reports that I have read. I think if that can be done well, that is really all that is needed.

CHAIR ABDEL-KHALIK: That coupled with the start-up testing?

DR. WALLIS: Yes, with the start-up testing, which, of course, is coupled to that, yes. Exactly. And you cannot divorce one from the other because how sure you feel about your ability to validate and predict influences how careful you are in your start-up testing.

And if it's fatigue failure you're looking for, you've got to wait for years before it happens. That is not a good approach at all.

MEMBER ARMIJO: IGSCC isn't fast either.

DR. WALLIS: Right. So I think that's enough on that. Thank you.

CHAIR ABDEL-KHALIK: Thank you.

Mr. Maynard?

MEMBER MAYNARD: Well, overall I think both the applicant's and the staff's presentations were very good and very informative. I was especially impressed with the applicant's ability to get the answers to look-up questions very quickly, rapidly, and get back to us on those. I think that was very helpful.

From the staff, the one area that gave me a little bit of concern was on the human performance discussion. I didn't get the level of confidence that the review was a real in-depth review there.

I don't have any real concerns or issues in that area from what I heard from the applicant and from what changes are being made, but that was one area from the staff's perspective that you might want to just make sure that there is a good review in that area.

Relative to the dryer, as far as for the presentation, I don't think we should try to focus on the details of the methodology. There's no way to bring everybody up to speed in all of that.

I agree with Dr. Wallis that I think the real key is tieing the links together as to what items are there relative to scale model testing, relative to the other plant data that really ties a link that says this is a reasonable approach to take.

I believe it's a reasonable approach. First of all, I think it's far better than the alternatives. The only alternatives that you really have are either to instrument the existing dryer or replace it. Either one of those I think is pretty extreme options that are bad overall.

To instrument a current one, you pick up a lot of radiation exposure. And it is very difficult to do good attacks on the strain gages and other instrumentation on a used piece of equipment in a high-radiation area. Putting a new dryer in definitely unnecessarily you have created a lot of unnecessary radioactive waste besides the expense and stuff.

And so from an overall public health and safety and what is right, I think those are two very poor alternatives in this case. So we get back to the methodology.

I find it acceptable because, again, the dryer mods that were made prior I think put this in a substantially better situation than some of the other dryers that have been evaluated, the current dryer performance and the load noise levels in there.

The methodology itself, while we may still have some questions, it has received an awful lot of scrutiny from the staff and from I believe credible consultants in this area that have taken a good, hard look at it. And, again, I think it probably is as good as what is available at this time.

I don't think we should ever rely totally on a method like this. I think that there are other things that give me the confidence. Quad Cities data that was reviewed after the failure occurred demonstrated that you can when looking at the various parameters outside the steam dryer, you can see things occurring that could indicate significant failure and things. So I think that provides confidence. And you don't necessarily have to have instrumentation on the dryer to get that kind of data.

And, again, the methodology isn't really being totally relied upon and shouldn't be. You have the testing approach that is monitoring certain parameters and things as you go up. You have stop points. And I believe that a combination of all of those things will identify potentially significant problems from occurring before they become catastrophic or real problematic.

And I also don't think just because some time in the future a small fatigue crack or something might be identified doesn't mean that this thing or that a decision has been made that is contrary to the health and safety of the public.

I believe that we need to avoid the things that are the catastrophic, the large things that could result in a release. And I believe that this provides an adequate level of assurance that with regard to the public health and safety that are going to identify the problem before it becomes a real big problem.

So those are my comments.

CHAIR ABDEL-KHALIK: Thank you.

Dr. Kress?

DR. KRESS: I guess it's unanimous on the steam dryer. I am fully in agreement with Sanjoy. I don't think it's a particular issue with this power uprate for Hope Creek. I do think it would be nice to close that loop. There may be issues with it on future plant upgrades. So I think it's not a thing for Hope Creek but something for the staff to do. And I would fully support that that gets closed.

I see no real stoppers in terms of granting the power uprate. I do have some thoughts about the way the staff reviews the risk assessment part. I don't want to comment on those at this time because I want to get my thoughts together on it. I will put them in writing in my consultant's report.

CHAIR ABDEL-KHALIK: Thank you.

Mr. Stetkar?

MEMBER STETKAR: Yes. Despite my rather critical comments on some parts of the risk assessment, I have to say that I was quite impressed with most of the licensee's efforts to demonstrate the risk implications from transitioning from the pre-EPU to the post-EPU conditions.

As you probably picked up by my comments, I would hope that in the full Committee presentation, there is some better, more coherent justification for how the internal fire, in particular, and to a lesser extent the seismic risk translates; in particular, because that may be a larger contribution to the total risk than the very good job that was done on the internal events.

Granted, we don't know the total contribution from internal fires due to a lot of the things that were discussed today, but there should be a way to estimate the differential contribution in a better method than has been done so far. So that's something to think about in terms of the full Committee presentation, at least in that topic.

CHAIR ABDEL-KHALIK: Mr. Sieber?

MEMBER SIEBER: I think overall there are good presentations, both from the applicant and the staff. And in general I thought they were very professional and covered all the issues that I would have that are matters of concerns in the EPU.

Yesterday I was in another subcommittee meeting. So I didn't have the benefit of the presentations from yesterday. I did get a briefing by other members on one of my interests, which is the fuel management aspects of this, and came away from that conversation impressed by the fact that the licensee in my opinion is probably spending a little bit of extra money in order to come up with a conservative fuel design. And having done that for about ten years in my own career, I can see what they did. And that was to make sure that they had plenty of margin for all of the fuel assemblies. And I think that that is good engineering intent as far as that aspect is concerned.

The dryer I think is another issue. I, like some others, don't fully understand all the implications of the calculations that have been performed.

And so I can't say with 100 percent certainty that acoustic measurements and various instrumentation on steam lines is going to tell you everything there is to know about dryers during start-up.

And it's not clear that because of the complex geometry of the dryers that you can do a good enough design to look at each and every weld and know all the dynamic forces inside the reactor vessel that will have an influence on particularly fatigue strength of the vessel.

What is important to me is enough assurance that the dryer won't come apart in the first few months of operation. And I think the analysis that has been done so far and past operating experience, this kind of dryer has been put to more severe service, I think, in a couple of other plants than it is being put to here, just by the size of the power uprate.

So I have the kind of confidence that at least it will make it through the cycle. And I think I compare in my own mind to power piping as an example. The code tells you how to design and erect piping systems. And manufacturers of pipe put some margin in the thickness and so forth.

And that doesn't say that that piece of pipe is going to be in service for 60 years and provide adequate service. And that's why we have programs like CHECWORKS and concerns about chemistry and so forth, but the key to that is inspections, the in-service inspection program, and management of the transients that you put on the device, the piping for the reactor and the dryer.

The fact that the approach to the extended power phase to me appears to be very careful, very deliberate with lots of whole points and so forth gives me some pretty good amount of confidence that the applicant will identify a significant failure in the dryer during the start-up phase.

And what we're concerned about is fatigue cracks that would lead to the failure of significant parts of the dryer. And so with the analysis that's been done and the slow start-up and all of the data that's going to be taken, I have some confidence that the dryer will last at least one cycle, at which time we have the first of three cycle inspections.

Now, I compare that to the same thing we do with piping and other pressure vessels and other components in the plant. You erect them according to the code. The code has safety margins built into them. And it is built to a certain amount of standards.

And if you really look at the history of the code, not all the factors are always in there. There's margin after margin after margin to make it easier for the field engineers to design and erect this stuff.

And so I think there's margin in this particular dryer also. And I rely on the careful start-up and the inspection program to give the amount of assurance that's necessary to say that it's okay.

Okay. So that's how I arrived at that because otherwise I don't think there's quite enough to unequivocally say that the dryer isn't going to fail after quite a number of years of operation.

You have to keep watching it, do inspections, and so forth. And I think that's what the applicant plans to do. At least that's what he stated he is going to do.

CHAIR ABDEL-KHALIK: Thank you.

I think, based on the comments, there is general consensus that this application should move forward to the full Committee. Is that the general consensus? We should be able to write a letter following the full Committee deliberations.

The question then remains as to which topics should be included in the full Committee presentation. Obviously we can't go through the entire -- and I have a list of four. And we may add or remove some of those. And that list of four is the steam dryer, the safety analysis, the containment analysis, and the PRA.

MEMBER MAYNARD: What about the fuel?

CHAIR ABDEL-KHALIK: I think that's part

of safety analysis.

MEMBER MAYNARD: Is that part of safety analysis? I think it's important because it is a mixed fuel.

CHAIR ABDEL-KHALIK: Right.

MEMBER MAYNARD: We have to include it in that.

MEMBER SIEBER: And we have a recent history that we still need to deal with on fuel. So I think that it should be there, too.

MEMBER BANERJEE: Perhaps with the fuel, in particular, it would be useful to clarify that GE methods and GE penalties that we put in the past wouldn't be adequate. And the reasons for this are clear, but it should be brought home very quickly that SVEA fuels don't necessarily require a whole new evaluation and all that sort of thing. That case must be made pretty succinctly and quickly.

CHAIR ABDEL-KHALIK: Right.

MEMBER BANERJEE: And the sort of incorrect fuel loading pattern that we had to begin with probably wasted one hour of the meeting.

MEMBER MAYNARD: We do need to be a little careful on the fuel analysis. There may be parts of that that's proprietary as with the dryer that we've got to be careful on when we start talking penalties and things there.

DR. WALLIS: That's what the designated letter --

MEMBER BANERJEE: One thing is to put the SVEA bundles right in the center and the others in the periphery so --

CHAIR ABDEL-KHALIK: I just want to make sure that you are not complying that the licensee should justify the appropriateness of the penalties that have already been imposed by the staff on GE methods.

MEMBER BANERJEE: I think the staff outside the scope of this application.

DR. WALLIS: Right.

MEMBER BANERJEE: I think the staff should --

CHAIR ABDEL-KHALIK: I think those four topics. Are there any additional topics that any of the members feel should be included in that list?

MEMBER ARMIJO: It doesn't have to take a lot of time. The work that's done on the water chemistry and IGSCC, IASCC of vessel internals, that's well-covered. Put it to bed.

MEMBER MAYNARD: I think it is included in one of those, but make sure the power ascension testing and monitoring is going to be adequate.

CHAIR ABDEL-KHALIK: Right. That's part of the steam dryer presentation ascension.

MEMBER MAYNARD: That's part of that.

MEMBER STETKAR: I think in the area of PRA, I don't think it requires a very lengthy presentation. And I would again emphasize not all the details about qualifying the PRA and things like that. Just focus on what was done to evaluate the difference pre-EPU/post-EPU. That shouldn't take much time.

DR. KRESS: And I would include in that interpretation with respect to whether or not it puts into question the adequate protection.

CHAIR ABDEL-KHALIK: The rationale.

DR. KRESS: That's the title. That's the title, the verdict.

MEMBER BANERJEE: If based on the discussions the staff decided to clarify some of the conditions that there was some discussion of that, then that probably should be done at the full Committee meeting, too.

MEMBER MAYNARD: I think the staff has to cover the license conditions, at least briefly, in the discussion there.

CHAIR ABDEL-KHALIK: I think he's referring to the GE methods.

MEMBER BANERJEE: No, no, not to the GE methods. I was talking about the dryer.

CHAIR ABDEL-KHALIK: Okay. Okay.

MEMBER BANERJEE: Not the GE methods. I think we don't want to get into OLMCPR, SLMCP. It would take the whole day.

CHAIR ABDEL-KHALIK: So you are talking about the dryer?

MEMBER BANERJEE: Right. Of course. That's part of the process. Because there was some discussion by the staff that they would do that.

CHAIR ABDEL-KHALIK: I hope that both the applicant and the staff are taking notes of this discussion.

MEMBER MAYNARD: If you give us long enough, we are going to have you cover all the items that the --

(Laughter.)

DR. WALLIS: The real safety and regulatory issues don't involve the steam dryer. I think that they should be covered first, and they should restrict the discussion of the steam dryer because it has risks getting blown out of all proportion.

CHAIR ABDEL-KHALIK: Right.

DR. WALLIS: So I think the applicant and the staff have to be very careful to focus on the essentials. It sends a message with the steam dryer.

CHAIR ABDEL-KHALIK: We have discussed focusing on the big picture, --

DR. WALLIS: Right.

CHAIR ABDEL-KHALIK: -- rather than getting into the details of the model so that --

DR. WALLIS: Well, if the big picture is clear, yes.

CHAIR ABDEL-KHALIK: Right.

MEMBER MAYNARD: I think we're going to have to help a little bit with that, with the other members. The staff and the applicant have some limitations on how they can control that. I think for some of the things that we beat to death in the Subcommittee meeting, we need to --

DR. WALLIS: I think you just hope that no other members read all the reports on the steam dryer as well.

CHAIR ABDEL-KHALIK: Are there any additional comments for information that we would like to convey to either the staff or the applicant?

(No response.)

CHAIR ABDEL-KHALIK: Well, on behalf of my colleagues, I would like to thank both the applicants and the staff for very information and well-prepared presentations. Thank you.

MEMBER SIEBER: Could you go over the items again?

CHAIR ABDEL-KHALIK: The items are steam dryer; power ascension testing; safety analysis, including core design; containment analysis; a short presentation on PRA; and a short presentation on water chemistry.

MEMBER ARMIJO: As part of the materials?

CHAIR ABDEL-KHALIK: Right. The meeting is adjourned.

(Whereupon, the foregoing matter was concluded at 5:34 p.m.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards

Docket Number: n/a

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Charles Morrison
Official Reporter
Neal R. Gross & Co., Inc.