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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

MEETING OF THE SUBCOMMITTEE ON POWER UPRATES

BEAVER VALLEY POWER STATION EXTENDED POWER UPRATE

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WEDNESDAY,

APRIL 26, 2006

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The subcommittee meeting convened at the Nuclear Regulatory Commission, Two White Flint North, Room T-2B3, 11545 Rockville Pike, at 8:30 a.m., Richard B. Denning, Chair, presiding,

SUBCOMMITTEE MEMBERS PRESENT:

RICHARD B. DENNING

, Chair

SANJOY BANERJEE

ACRS, Consultant

THOMAS S. KRESS

OTTO L. MAYNARD

JOHN D. SIEBER

GRAHAM B. WALLIS

ACRS STAFF PRESENT:

RALPH CARUSO

FIRSTENERGY STAFF:

BOB BAIN

Stone & Webster

DON DURKOSH

FENOC

BILL ETZEL

FENOC

KEN FREDERICK

FENOC

DAVID GRABSKI

FENOC

JEFF HALL

Westinghouse

NORM HANLEY

Stone & Webster

GREG KAMMERDINER

FENOC

COLIN KELLER

FENOC

JAMES LASH

FENOC

MARK MANOLERAS

FENOC

PETE SENA

FENOC

GEORGE STORLIS

FENOC

MIKE TESTA

FENOC

NRR STAFF PRESENT:

TIMOTHY COLBURN

STEVEN LAUR

GREGORY MAKAR

ROBERT PETTIS

MARK RUBIN

THOMAS SCARBROUGH

ANGELO STUBBS

A-G-E-N-D-A

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

8:33 a.m.

CHAIRMAN DENNING: We are now back in session. And this is Wednesday, April the 26th. And we're going to start off discussing mechanical impacts and Mike Testa.

MR. TESTA: First I'd like to thank the Committee for the opportunity to speak here today. My name is Mike Testa, I'm the extended power uprate Project Manager for Beaver Valley.

A little background on myself. I have 23 years of experience at Beaver Valley Power Station. The last five year I've been the uprate Project Manager and I also was on the full potential project from the beginning.

Today I'll be discussing the mechanical impacts that the uprate has on Beaver Valley Power Station.

Next slide, John.

I'll be discussing the steam generators, balance of plant heat exchangers, vibration monitoring program for the secondary piping systems, cooling water systems and flow accelerated corrosion, of which we'll have our program owner come up and speak on that program.

Today if there's any questions, I have Jeff Hall from Westinghouse to assist me as well as Bob Bain from Stone & Webster.

For steam generator vibration, we looked at the first thing, we used a thermal-hydraulic code Athos that computes the thermal-hydraulic parameters the tubes so the tube bundle would be subjected to.

We looked at the vibration potential in the U-bend and tube bundle entrance region. Out of two vibration mechanisms that were considered, were fluid-elastic instability, vortex shedding and random turbulent excitation.

And we also looked at tube wear. And that's tube wear in the U-bed radio at the antivibration bar interface.

The tube bundles, just the difference between the units now. For Unit 1 we replaced the steam generators. We discussed that yesterday. Model 54. Just installed in fact a few weeks ago here. The model 54 was designed for uprate conditions so the stress report, the design report considered uprate.

For Unit 2 we have the Series 51 steam generator, of course, which now will see increased flow because the uprate.

We reviewed the --

MEMBER WALLIS: I presume the steam generators is plural and you installed three of them?

MR. TESTA: Yes.

MEMBER WALLIS: Not just one?

MR. TESTA: Yes, correct. That's correct. Yes. Three loop PWR 3 steam generators.

We looked at the flow induced vibration effects --

DR. BANERJEE: What's the difference between the two?

MR. TESTA: Between a model 54 and 51?

Jeff?

MR. HALL: Yes. This is Jeff Hall from Westinghouse.

The differences are really many. With respect to the tube material itself the 51M is a 600 mm tubing where the 54F is a 690 thermally treated tubing. So issues such as stress cracking are greatly reduced with the new model generator.

The support plates are stainless for the new model generator versus carbon steel support plates.

The antivibration bars are better

designed for the new unit.

DR. BANERJEE: What does that better design mean?

MR. HALL: The support conditions are more assured. Where for the 51M sometimes you could pick up gaps between AVBs and the tubes, with the newer design with the reduced gaps you have a reduced potential for wear at the AVB sites.

DR. BANERJEE: So are these just gaps or are there actually things holding the tubes in place?

MR. HALL: Well, you could think of it as a bar that's inserted between the tubes in the U-bend region. It's a flat bar. Essentially it provides a support location to prevent the tube from moving in the out of plane direction.

DR. BANERJEE: But they're not broach plates or anything like that?

MR. HALL: Well with respect to the support plates. The support plates are in fact broached.

DR. BANERJEE: Okay.

MR. HALL: Where the 51M is a circular drilled hole.

DR. BANERJEE: And the 54F?

MR. HALL: The 54F is a broached configuration.

MR. KAMMERDINER: Excuse me, Jeff. This is Greg Kammerdiner.

Back on the AVBs, the other difference with the 54Fs, there's an extra set of AVBs. 51s have two sets of AVBs, the 54s have three. So there's more support in the upper bundle because there is an extra set of AVBs in the 54.

DR. BANERJEE: And the number of tubes are the same?

MR. KAMMERDINER: There's approximately 400 tubes more in the 54?

MR. HALL: Yes.

DR. BANERJEE: Four hundred out of how many?

MR. KAMMERDINER: The 51Ms have 3,376. The 54s approximately 400 more.

DR. BANERJEE: Ten percent more?

MR. KAMMERDINER: Yes.

DR. BANERJEE: Thanks.

MR. KAMMERDINER: Fifty-four stands for 54,000 square feet of heat transfer area. The 51, is 51,000 square feet.

DR. BANERJEE: Thank you.

MEMBER WALLIS: So the AVBs limit the amplitude of the oscillation, but they also give the tubes something to rub against, to bang against?

MR. HALL: Yes.

MEMBER WALLIS: Well, they're good and bad at the same time in a way.

MR. HALL: Beg your pardon?

MEMBER WALLIS: They're both and bad?

MR. HALL: Well, yes. No, they're actually all good.

MEMBER WALLIS: Okay. But it says here tube wear at IBBs. There is some rubbing or something going on?

MR. HALL: Yes. And that's primarily a result of the fit up between the tube and the bar itself. If you have the ability to move back and forth, well the tube is going to move back and forth. But if you're holding it sufficiently so that you don't have relative motion, well then you don't get wear.

MEMBER SIEBER: The AVBs go in the U-bend area, not below?

MR. HALL: That's correct.

MEMBER SIEBER: The old ones sometimes they weren't long enough to catch all the tubes. So you would end up with a tube that's not supported.

MR. HALL: Yes. And actually in both cases, the 51 in particular, there are some tubes in the U-bend region that are unsupported.

MR. TESTA: And actually, that's a lead in for the next bullet where we looked at -- go back, John.

Yes for Unit 2 again for the series 51, unsupported U-bends were reviewed for increased fatigue. And because the analysis that was performed, there was six tubes that we had to take out of service. And we did that.

Okay. As far as the next slide here, I just wanted to touch on the steam dryer. Again, look at the comparison between the PWR and the BWR. Just a little description on the secondary steam dryers on the steam generators. Now the main difference is between the 51 and the 54 is that the 51s have a two tier arrangement for the secondary dryers. I have sketch behind this to show that, whereas the model 54 has a single tear arrangement.

It's better illustrated here. Again, with the 51 they have two tiers of secondary steam dryers. You can see the lines that are drawn. The steam comes up and enters into the side region of the secondary dryer and then flows up, comes up through and then has a natural progression up through the secondary dryers.

The flow velocity in that region is on the order of 3½ to 4 feet per second. And you can see the vicinity of the nozzle region there's no structural components within the vicinity of the nozzle.

CHAIRMAN DENNING: I realize that later you're going to talk a little bit about experience. But could you tell us at this point how much experience is there with the 51 at the conditions that you're now going to go to?

MR. HALL: With respect to these conditions there's an immense amount of experience. These steam dryers, this configuration is used in a multitude of steam generator models, not just the 51s. The D models, D2, D3, D4, D5 all have a very similar arrangement. 54F a very similar arrangements. The Fs all have a two tier arrangement.

The velocities coming out of that area are all pretty much of the same order of magnitude. I mean, a couple of feet per second one way or the other, but they're all essentially the same.

Totally different orders of magnitude than some of the boiling water reactor dryers.

MEMBER SIEBER: Well, the one thing you don't have is a 180 degree change of direction.

MR. HALL: And all the consequences of that with respect to the turbulence that you can get, yes. It's all pretty much it comes out of the steam dryers and it continues on right up to the steam nozzle.

MEMBER SIEBER: The velocities are pretty low. They're like --

DR. BANERJEE: Can you stay there. Can you go back to that slide?

MR. TESTA: That one?

DR. BANERJEE: No, no, no.

MEMBER WALLIS: The velocities?

DR. BANERJEE: Yes.

MEMBER WALLIS: The one with the velocities, 107.

DR. BANERJEE: The velocities.

MEMBER WALLIS: That's it.

DR. BANERJEE: That's it.

MEMBER WALLIS: There's no history of problems with these dryers, I understand?

MR. TESTA: That's correct. In fact here

from this slide here it was to compare, again the 51 to the BWR. You can see that they have low velocities up through the dryers at 3½ to 4 feet per second where the BWR was on the order of 100 feet per second. And there have been no operational issues reported in the 51s or the 54s.

We had a backup slide just to show the operating experience.

DR. BANERJEE: Can you, please?

MR. TESTA: Sure. Okay. So for example, you know, well Beaver Valley which is going to operate at 2910. The difference with the model 54 one tier secondary dryer in the Unit 2, with two tier you can see the comparison to the other plants that utilize the similar secondary steam dryer arrangement.

MR. HALL: Yes, but these are not the only plants to have this particular dryer arrangement, too. There's many more.

MEMBER SIEBER: As far as megawatt production, Beaver Valley and North Anna are about the same so the operating experience from North Anna at that power level, it's got a fair amount of time behind it.

MR. TESTA: That's correct.

MEMBER SIEBER: So they aren't really breaking any new ground here.

MR. TESTA: In fact, North Anna is on the list here where they're operating at 2905.

MEMBER SIEBER: Got them beat by five?

MR. TESTA: Yes. Okay. Okay, John. No, go forward.

Now if there's no other questions on the steam generator, we also looked at balance of plant heat exchangers. From the uprate looking at the heat balance and the flow parameters that the equipment would be subjected to. We looked at the feedwater heaters and the feedwater heaters will operate within the design capacity.

The moisture separator reheaters, we went back to the vendor. We had a specific analysis performed to show acceptability under the increased flows.

As we mentioned yesterday, one of the modifications that we're going to do is on the condenser. Now our Unit 1 condenser was retubed a while back. And at that time the condenser was staked. Prior to the power escalation we will be taking the condenser in order to limit the tube vibration.

Vibration monitoring. This is a monitoring program for the secondary side for the balance of plant piping. We're going to monitor the secondary systems pre and post-EPU. This is going to include baseline walkdowns on each of the plants which we've already done. We have documented walkdowns.

Areas of interest where there's level of vibration that causes us to pay particular attention as we escalate power, we've identified those locations.

All this is within the guidance of ASME OM Part 3 that prescribes the walkdowns or the acceptance criteria that could be used and the method of performing this program.

CHAIRMAN DENNING: Could you help me a little bit on a walkdown where you're looking for vibration, what does one do quantitatively there?

MR. TESTA: Okay. What we do there is, for example, we came up with a screening criteria. We're looking at the displacement I'd say on the order of an eighth of an inch. And we'll walk it down to see if there's any signs, any noticeable signs of vibration. And we basically have documented from the plant, basically going from say component to component, basically identifying if we have vibration levels that would exceed that limit.

CHAIRMAN DENNING: Visually?

MR. TESTA: Visually. That's correct.

I have Bob Bain from Stone & Webster. If you'd like to add?

MR. BAIN: Yes. This is Bob Bain from Stone & Webster.

We followed the basic guidance of OM3 as Mike says. The first test criterion we used was visual on displacement of an eighth of an inch, which is within the guidance provided in OM3. They allow for visual measurements using simple devices such as rulers, hand held type mechanical simple devices like pencils, literally. And an eighth of an inch peak to peak displacement is easily visual on a focused walkdown. And as Mike says, these walkdowns were basically focused.

Over the last three or four years, actually, we took a schematics and basically connected the dots from equipment. So from pump to valve, valve to vent or drain, vent or drain to branch lines. So it was a focused walkdown looking at the piping, the components as well as the support hardware.

And any observation, again eighth of an inch was a fairly stringent criteria. Easily visually noted. That would get it onto this list of interest, as Mike identified.

And we followed up that list of interest literally over the last three or four years for both units.

CHAIRMAN DENNING: Is there quantitative stuff that one can do? I mean, are there instruments that you can go and put it up against the machine? I mean, the equipment --

MR. TESTA: Yes, there are.

CHAIRMAN DENNING: -- and have a measure of not only the displacement but the frequency?

MR. TESTA: Yes. There's a portable device, hand held accelerometers. And, again, we conduct these walkdowns. We use the experienced engineers. And if there's any question about the acceptance of the level of vibration, then we will use accelerometers to record the displacement and the frequency.

MR. BAIN: Yes. This is Bob Bain again.

And this hand held equipment that Mike references actually gives you data in displacement or velocity or acceleration. And OM3 allows you to do more detailed evaluations if required using velocity or displacement data. So the hand held is a good device to give you the next level of detail quantitatively.

MR. TESTA: Okay. Just the last mention here, large equipment like the reactor coolant pump and the turbine have continuous monitoring available. So we'll be monitoring that as we escalate power.

Okay, John.

Now the next area we looked at is cooling systems. The bottom line here is that the systems remain capable of dissipating heat for normal shutdown and accident conditions.

WE looked at these following systems, the flows were adequate without modification:

The river water system. Beaver Valley 1 the equivalent system service water for Unit 2;

The component cooling water;

Residual heat removal, and;

The safety injection containment depressurization system which uses the recirc spray heat exchangers.

Next slide.

Spent fuel cooling. We looked at spent

fuel cooling. As part of the project or the overall initiative, which we started we said five to six years ago, we looked at spent fuel cooling. And there was an amendment that we put in where we looked at the offload time. At that time we performed the analysis to incorporate the uprate decay heat loads.

MEMBER KRESS: Do you have dry casks on the site?

MR. TESTA: Not at this point, no. Still use the fuel pool.

MEMBER WALLIS: I think I remember your burnup is the same as it was before essentially, is that right?

MR. TESTA: Yes, I believe so. Yes.

The last area to touch on here is the auxiliary feedwater system. The auxiliary feedwater is fed from the condensate storage tank. The condensate storage tank is sized for 9 hours of hot standby conditions. And with the uprate or the increased decay heat, we've revised the tech specs to require 130,000 gallons useable volume for each of the tanks for both Unit 1 and Unit 2.

The other thing with the aux feedwater system, there were two accidents: The feedline break and loss of normal feed that required us crediting two aux feed pumps.

CHAIRMAN DENNING: I didn't understand with regards to the tech spec limit and the 130,000 gallons. What do you do physically to assure that?

MR. TESTA: Basically we have the calculated tank volume and maintain a level on the tank.

CHAIRMAN DENNING: So it's a level on the tank that has to be assured now that it's slightly higher than it was previously?

MR. TESTA: Yes. Yes.

CHAIRMAN DENNING: Gotcha.

MR. DURKOSH: This is Don Durkosh from Beaver Valley Operations.

Basically we obtained curves that show based on indications available to us what the volume is. And on every shift we have minimum levels that we're required to verify on a shiftly basis. So that's how we maintain our minimum tech spec values.

MEMBER MAYNARD: You didn't make any modifications to the tank. You're just changing the level setpoint there.

MR. TESTA: That's correct. That's correct.

MR. CARUSO: Why would you not normally keep the tank full?

MEMBER SIEBER: It goes up and down. You have to have surge volume.

MR. TESTA: To answer that question we normally do. As part of the review of our L5 logs we typically, our levels are high. What we try to do is basically clear the alarms. We have a low alarm that indicates we're approaching a tech spec limit. And normally we have a high alarm very close to the overflow. So we try to maintain it within that range so we have no alarms in the control room.

MR. TESTA: Okay. Again, just to finish this out here, there are two accidents that required us to credit two pumps. This was already in place for Unit 2. And with the revised analysis Unit 1 will now require two pumps also for these two accidents. It's basically accounting for the increased decay heat plus the addition of the cavitating venturies, which puts a little more system resistance into the system.

CHAIRMAN DENNING: And that's two out of how many?

MR. TESTA: Two out of three.

CHAIRMAN DENNING: And it had been one

out of three?

MR. TESTA: It had been one out of three, just for Unit 1. Unit 2 was already crediting two pumps.

Okay. Well, this completes my part of the discussion. I have Dave Grabski here, which he's our flow accelerated corrosion program owner, and he'll talk about the program.

Thank you.

MR. GRABSKI: As Mike said, I'm Dave Grabski. I am the FAC program owner.

A little background. I'm a FirstEnergy employee. I worked at Beaver Valley and before that Shippingport Atomic Power Station for a combined 26 years.

I've been the FAC program owner since the early '90s.

Next slide.

The first bullet, the EPU effects evaluated using CHECWORKS. So we've taken the revised heat balance diagram parameters and using the CHECWORKS models determined analytically what we'd expect as far as our wear rates. With most uprates, we've seen an increase in velocity and temperature. And those two factors play differently with different systems. Some systems we've seen a decrease in our wear rates, and others we've seen a slight increase.

The feedwater and extraction steam systems, those systems had a decrease. Systems like the feedwater heater drains, condensate have increased. Again, because of the play of those different parameters: Velocity and temperature mainly.

In preparation for the uprate we've actually replaced two extraction steam Ts because of the increase in our SMR relief valve set point that has cut into our margin between our measured wall thickness and our required wall thickness. Extraction steam is one system at Beaver Valley that does wear due to the flow accelerated corrosion mechanism.

CHAIRMAN DENNING: So there wasn't a materials change, it was just a thickness change?

MR. GRABSKI: We have upgraded the material to a chrome-molly. Basically anytime we make piping replacements at Beaver Valley, we'll upgrade to a chrome-molly. Chrome-molly is much more resistent to this particular degradation mechanism.

Based on the engineering evaluation we're going to focus on a few more systems. Well, not more systems, but more components within those systems, on those systems that we expect an increase in velocity. Mainly our moisture -- or I should say the heat drain system from our 4th to 5th point heaters, we had a significant velocity there. So we're going to focus examinations in the next outage there to get a baseline where we're at. And in the future go back to these areas to see how they're doing.

And there's some components at Beaver Valley 1 and 2 in the 4th point heat drain line. It's showing you in the next to the last column there some of the wear rates we saw before the outage. Very low. And heater drains is a low wear system at Beaver Valley. But we do see some increases based on the uprate.

DR. BANERJEE: Do you have a diagram showing where these components are in the steam cycle?

MR. GRABSKI: I don't have --

DR. BANERJEE: I have no idea where the four point heat is or what -- I imagine that it's extraction --

MEMBER WALLIS: This is a preheater.

DR. BANERJEE: Preheater?

MR. GRABSKI: Yes. We have six --

MEMBER WALLIS: Well, these aren't safety concerns anyway. These are just embarrassments for you if you break a pipe, it might be dangerous for anyone who is around the pipe.

MR. GRABSKI: It could be a personnel issue.

MEMBER WALLIS: It's dangerous for your people, but it's not a nuclear --

MR. GRABSKI: That's correct. This is a non-safety related piping systems.

MR. STORLIS: My name is George Storlis. I'm a FENOC employee.

An in Operations I can get a little bit of perspective to what the feed heater string is. The feed heater string is compromised of six feed heaters in line with the condensate feed system to preheat the feed. The fourth point is fourth in line, the sixth point being the lowest energy or lowest pressure system and the first point being an extraction steam of highest pressure off of the turbine cycle. And the fourth point is in route to that.

And we're talking pressures, temperatures that compliment the feedwater heat up that approaches the 440 degrees or so when it ultimately is arriving at the steam generators. So it takes a portion of the energy from the turbine cycle and uses that to preheat the steam and the shelf tube arrangement.

And that's the basics of it. If there's any questions, please ask.

DR. BANERJEE: Is the steam wet at this point?

MR. STORLIS: Yes. Yes.

DR. BANERJEE: What's the quality?

MR. STORLIS: Without having the curves and the diagram in front of me, I can't speak to that, that specific quality.

MR. KAMMERDINER: Probably some in the 90s.

MEMBER WALLIS: Pretty high.

MR. TESTA: This is Mike Testa.

We have a heat balance diagram, maybe that would help.

DR. BANERJEE: Does it show quality at various points, extraction points?

MEMBER SIEBER: That chart would work.

DR. BANERJEE: I can't do it in my head.

MEMBER WALLIS: And the problem is the wetness, presumably.

DR. BANERJEE: Yes, the wetness.

MEMBER WALLIS: But it's a few percent. It's not a humongous amount or is it designed to extract in a way that it separates the wall, and it would be wetter, wouldn't it?

MR. GRABSKI: Actually the steam quality is fairly low.

MEMBER WALLIS: That's in the turbine. But when you extract, don't you sort of have something that's centrifugally separates or anything like that?

MR. GRABSKI: We have steam traps and orifices to pull off the moisture.

MEMBER WALLIS: It's an oxidate or whatever it is that comes out, ends up in some condensate -- where does it go?

MR. GRABSKI: It varies with the system that might be wearing. If you're feedwater's wearing, you're going to get it in the steam generators on secondary side. A lot of the heater drains go to a receiver tank.

MEMBER WALLIS: The crude appears in the

steam generator. Where does the stuff that's worn away from the pipe?

MR. GRABSKI: Again, depending on what system it's in. The heat drains, there's a heat drain receiver tank that it could filter out at. We do have -- do you have something?

MR. HANLEY: Yes. Norm Hanley from Stone & Webster.

All the secondary side condensate and extraction steam heater drains all recovered. Some of it cascades back to the condenser, some of it's pumped forward to the feed pump suction. So it is all recovered.

MEMBER WALLIS: Isn't a lot of it dissolved and then it appears somewhere else in an--

MEMBER SIEBER: Heater drain and steam generator.

MEMBER WALLIS: In these steam generator?

MEMBER SIEBER: Yes. There is a blow down line on the steam generator.

MR. HANLEY: Right. There's a blow down in the steam generator. They also sample the secondary side.

MEMBER MAYNARD: Well, do you have

condensate polishers? Do you run it through --

MEMBER SIEBER: Only on Unit 2.

MEMBER MAYNARD: Only on Unit 2.

CHAIRMAN DENNING: Can you comment on the accuracy of CHECWORKS? I mean, obviously, it's not the four significant figures that's in that table.

MR. GRABSKI: Basically the models will improve with the number of examinations you do on the system. It correlates with the data you have. So without any data, I would take it as just a ranking. And that's what we use it for, as a ranking. But actually in our extraction steam which we examine the heck out of, they actually correlate pretty well once you get enough data in there.

MEMBER MAYNARD: I take it you also use industry experience what's found at other places --

MR. GRABSKI: Oh, absolutely. Our examinations are the backbone. But certainly ops experience, trending of data at our plants and then that's all factored in.

DR. BANERJEE: Is there any increased erosion due to the wet steam, the velocities being somewhat higher or --

MR. GRABSKI: Yes. That's in the

CHECWORKS algorithm higher velocity results in a higher wear rate.

DR. BANERJEE: Due to erosion or is it some erosion/corrosion?

MEMBER WALLIS: I suspect it includes both erosion --

MR. GRABSKI: The FAC takes in the both. That's the mechanism.

DR. BANERJEE: But does it also depend-- does this depend on the wetness as well?

MR. GRABSKI: Absolutely. That's a factor in the algorithm.

DR. BANERJEE: You feed this stuff into CHECWORKS and out comes these numbers?

MR. GRABSKI: Yes.

DR. BANERJEE: Hopefully.

MR. GRABSKI: Hopefully, yes.

DR. BANERJEE: Yes. Who developed this thing?

MR. GRABSKI: EPRI developed CHECWORKS. And it's the industry --

DR. BANERJEE: Probably validated against data?

MR. GRABSKI: They call it an empirical study --

DR. BANERJEE: I see.

MR. GRABSKI: -- based on lab and actual events in the industry.

MEMBER KRESS: There's sort of a Bayesian update. You go in and inspect and you compare the inspection findings, and then you adjust CHECWORKS to better agree with your findings?

MEMBER WALLIS: Learns about your --

MEMBER SIEBER: Putting your own data --

MR. GRABSKI: Exactly. As I said, they call it a pass one without any data. Once you get enough data in there, it correlates itself. And you have a line correlation factor, it's called.

DR. BANERJEE: So the predicative capability is always in question of these types of things? It's only as good as your database?

MEMBER SIEBER: By the time you are ready to decommission the plant, it will be very --

DR. BANERJEE: Yes, it'll be excellent by them.

MEMBER KRESS: Or by the time you're ready for a license extension.

DR. BANERJEE: Extrapolation is always dangers in these sorts of things. There's no theory or model there, right?

MR. GRABSKI: Well though EPRI calls it a model and it certainly does take into consideration velocity, temperature --

MEMBER MAYNARD: And geometry, right?

MR. GRABSKI: And geometry. Exactly. But again, it's as good as the data you're putting into it at the point.

DR. BANERJEE: Let's imagine that we take this today with the data you've got and try to predict what will happen two years from now. Has it ever been tested in this mode to show whether it gives a reasonable prediction?

MR. GRABSKI: Yes, I think it has.

DR. BANERJEE: It does?

MR. GRABSKI: Yes, it does. It certainly. Yes. It'll give you --

MEMBER MAYNARD: Isn't the main purpose of it, though, to predict areas where you may have high wear rates and that you inspect those and that you put those in your trending program? And you're actually using more actual trend data than you are a prediction from the program as to when that line might break?

MR. GRABSKI: Exactly. It gives you the places to look first. The highest susceptible line.

And I think it does a very good job of that. But once you get into a qualitative or quantitative measure, that's when you need to get some data in there to verify what the model is telling you.

You may be right on the money, but again once you get more and more data in there, you correlate the model and then it becomes a very good predictive tool.

MEMBER MAYNARD: Yes. Most of the plants do a lot of measuring of a large number of areas where they measure and periodically do that so they can see what's trending.

MR. GRABSKI: Exactly.

MEMBER MAYNARD: It's not just using a computer program to --

MR. GRABSKI: No. Your data proves it, but it's a great start because it's going to tell you that this T is more susceptible than this T, elbow to elbow.

MEMBER MAYNARD: But again that's the way the nuclear safety issue other than if it could result in an unnecessary plant transient or it may be a personnel safety, but from a nuclear safety accident it's not.

MR. GRABSKI: That's true.

MEMBER SIEBER: And if you take a big fitting like an elbow or a T, a single measurement is inadequate. You have to basically put a grid on that fitting.

MR. GRABSKI: Right.

MEMBER SIEBER: Take a lot of measurements of different positions. Because the wear will be local to someplace where there is an eddy in the flow stream.

MR. GRABSKI: That's correct.

DR. BANERJEE: Have you seen any erosion in the high pressure stages?

MR. GRABSKI: Excuse me?

DR. BANERJEE: Did you see any erosion at all in the high pressure stages?

MEMBER SIEBER: Main feed?

DR. BANERJEE: Yes.

MR. GRABSKI: Some feedwater, we have very low wear rates there. In our main steam coming off the steam generators, we haven't seen any wear--

DR. BANERJEE: What about the turbine plates, any erosion there, high pressure plates?

MR. GRABSKI: I don't know. That's not my expertise on the turbine.

MEMBER SIEBER: But generally speaking--

DR. BANERJEE: You should have any.

MEMBER SIEBER: -- what erosion you see, you see at the very -- the exhaust end of the turbine. And if your moisture separators and everything are working properly, you don't see hardly anything at all.

DR. BANERJEE: Not in nuclear plants, but some fossil plants you do because of the oxide--

MEMBER SIEBER: Well, generally the fossil plants are better than the nukes because they operate at a higher temperature.

MR. GRABSKI: That's true.

DR. BANERJEE: Yes. But the oxide flakes come and hit the high pressure stages sometimes, depending on how you cycle the plant. But you don't see any so the higher velocity doesn't give you a problem?

MR. GRABSKI: Again, I'm not a turbine guy.

DR. BANERJEE: Right.

MEMBER WALLIS: It's not a nuclear problem. It's not a nuclear safety problem. Just expensive if you have to fix the turbine.

CHAIRMAN DENNING: I think we're completed them, yes?

MR. GRABSKI: Yes, unless you have any questions.

CHAIRMAN DENNING: I think we're good. Thank you.

MR. GRABSKI: Thanks.

CHAIRMAN DENNING: And I think NRR now is going to present in the same basic area.

MEMBER WALLIS: They're going to defend CHECWORKS, are they?

CHAIRMAN DENNING: You can go ahead.

MR. SCARBROUGH: Thank you.

Good morning. I'm Tom Scarbrough in the Division of Component Integrity of NRR. And with me today is the Branch Chief in Division Engineering, Kamal Manoly and Dr. John Wu.

We're going to talk about the engineering mechanics aspects of the review. In terms of the components evaluated, they included the reactor vessel, the internals, the nozzles, supports, control rod drive mechanisms, the steam generator, reactor coolant pumps, the pressurizer and the supports, nuclear steam supply system and balance of plant piping systems and supports and safety related pumps and valves. Motor operated valves, air operated valves and safety relief valves.

The scope of the review included the impact of the EPU conditions due to changes in system pressure, temperature and flow rate.

The review of the licensee's evaluations of EPU conditions including the analytical methodology, loads, flow-induced vibration, calculated stressed and cumulative fatigue usage factors, acceptance criteria, ASME codes and addenda, functionality impact of EPU on Generic Letter 89-10 for motor operated valves and Generic Letter 95-07 for pressure locking and thermal binding of power operated valves.

The license's EPU evaluation does incorporate an improved leak before break criterion that allows elimination of postulated primary loop pipe breaks in the original design basis analysis. And after elimination of the primary coolant loop breaks by the application of the leak before break criterion, the existing design bases analysis for NSSS piping and components are bounded for the EPU evaluation considering postulated smaller branch line pipe breaks.

The specific areas where the Staff requested additional information included the main steamline and feedwater line flow-induced vibration due to increased flow rate, quantitative analysis and results for the Beaver Valley Unit 1 replacement steam generator, calculation of cumulative usage factors for the vessel flange closure stubs, considering 10,400 cycles as opposed to the 18,300 cycles of the design bases.

With respect to flow-induced vibration in particular, the main steamline and feedwater piping are instrumented at critical locations to monitor vibration levels at current rate of power and during power ascension up to full authorized EPU power level. The vibration monitoring and the collective data will be evaluated according to ASME Standard and Guide 2003 Part 3.

The flow-induced vibration effect on the steam separators and the steam generators is expected to increase somewhat for EPU conditions. Based on the licensee's response to the request for additional information to the request for additional information, the potential for flow-induced vibration of the steam separator is minimized due to its high stiffness resulting in a high natural frequency combined with a low velocity. And we heard about it, it's about 4 feet per second or so of passing flow. And past inspection performed for steam generator, moisture separators on operating PWR, pressurized water reactor plants have found no indications due to flow-induced vibration fatigue.

The flow-induced vibration on the U-bend tubing and the steam generators is within allowable limits. In other words, the fluid-elastic instability ratio was maintained less than the limit of 1.0. And peak stresses are less than the material endurance limit.

There were some pump and valve modifications to accommodate the EPU operations. These are relatively minor considering the 7 percent EPU power uprate. The charging and safety injection pumps have been modified to improve their high head performance and flow rate.

The tolerance settings for the main steam and safety valves and reactor coolant pressurizer safety valves have been adjusted.

New trim was installed in the feedwater regulating valves in Beaver Valley Unit 1 and those valves were replaced at Beaver Valley Unit 2.

Fast acting main feedwater isolation valves were installed in Beaver Valley Unit 1 similar to those in Unit 2.

And based on the Staff's review our conclusion is that the calculated stresses and accumulate usage factors in the NSSS and balance of plant piping and components are bounded by the original design basis analysis with the application of the leak before break technology, such that the postulated primary loop pipe breaks are eliminated.

The potential for flow-induced vibration is not increased for steam separators and the steam generator tubes at EPU conditions.

The main steamline and feedwater line piping is monitoring to remain within the allowable limits in accordance with ASME OM3 code guidance.

The NRC Staff reviewed the licensee's assessments related to functional performance of safety related valves and pumps at Beaver Valley for EPI conditions and based on that review the licensee has adequately addressed the EPU effects on safety related pumps and valves. And as a result, the Staff concludes that the licensee has demonstrated that the safety related valves and pumps will continue to meet their NRC regulatory requirements during EPU operation at Beaver Valley.

So we'd be happy to answer any questions you might have.

CHAIRMAN DENNING: I think this is pretty clean. Any questions? Okay. Thank you.

MR. SCARBROUGH: Thank you.

MEMBER WALLIS: Are we gaining time here?

CHAIRMAN DENNING: Oh, yes, we're gaining time.

We're going to go ahead with the next presentation.

An NRC presentation. By Gregory Makar.

MR. MAKER: Good morning. I'm Greg Makar. I am in the Division of Component Integrity. And my branch works on issues of steam generator integrity and other chemical engineering topics. And this morning the Staff reviews in five areas: Low accelerate corrosion, steam generator tube integrity, the steam generator blowdown system, chemical and volume control system and finally coatings.

Our review of flow accelerated corrosion begins with determining of the licensee has evaluated the changes due to the extended power uprate on the parameters like temperature, velocity, moisture content that are the keys in controlling flow accelerated corrosion rates. They did this and based on the known effects of this parameters, you see as Mr. Grabski explained, cases where the corrosion rates would be expected to increase and some where it would be expected to decrease.

MEMBER WALLIS: The boron content has no effect on any of this?

MR. MAKER: Excuse me, boron --

MEMBER WALLIS: Boron doesn't seem to be a parameter that comes into this at all?

MR. MAKER: No.

MEMBER WALLIS: This is simply because it's ignored or because it's proven to have no effect?

MR. MAKER: Well, if it changed the pH, say, then if the pH decreased because of it. But as I understand it, the pH does not decrease significantly enough to change the corrosion rate in this case.

So to satisfy that they were scoping things in properly, there's also the question of scoping things out because you want to keep your resources focused where they're needed. And there are criteria. And all of these cases we're going primarily by the EPRI guidelines on flow accelerate corrosion programs. That scoping out components based on things like temperature below 200 degree Fahrenheit, the chromium content being 1 and a quarter percent or higher. And this they're doing according to the EPRI guidelines.

DR. BANERJEE: Does NRC have any programs which independently check EPRI sort of guidelines and things?

MR. MAKER: No. No, computer models or programs.

DR. BANERJEE: Even the research programs or whatever?

MR. MAKER: No.

DR. BANERJEE: How do you know that -- do you audit it in some way other than just take their data or what?

MR. MAKER: The way that we evaluate this is by -- the NRC in the past was involved in developing a response flow accelerate corrosion and understanding the parameters that are the key influences on it. And I think at that time we did have research programs to determine those. I think we were in the lead at that time and helped lead industry toward a resolution and a development of the computer based programs. And followed and participated in research efforts to understand all the parameters and their influence.

DR. BANERJEE: So when did that effort terminate within RES or wherever in NRC it was?

MR. MAKER: I'm sorry. I don't know the answer to that.

DR. BANERJEE: Was it a long time ago or recently?

MR. MAKER: Well, several -- I don't know. And currently we sent -- for example, we send people to training to understand how CHECWORKS is used.

DR. BANERJEE: That's an EPRI training?

MR. MAKER: Yes. But the effect of these parameters on low accelerated corrosion is fairly well understood now. And I think the most value on making sure the licensees are following these programs and using -- skipping ahead a little bit. But the computer models for plants are one factor. But really the key is actually inspecting systems at repeatable locations and developing data so that you can then trend and determine corrosion rates. That allows you to make decisions about future inspections and replacement repairs. And also it improves the quality, the predictive ability of the model.

DR. BANERJEE: Does this apply mainly to components that can be inspected then or there components which inspection is difficult?

MR. MAKER: Yes. It should apply to all. There are cases where it's difficult to inspect components. And in that case what the licensees may do is go to a secondary inspection or a testing technique such a radiography, which isn't as good as ultrasonic testing. Or they may have another similar system behaves, is nearby, say, same type environment which behaves in the same way. And they'll use that --

DR. BANERJEE: So you're talking mainly of the secondary side rather than the primary side?

MR. MAKER: Yes. Yes.

DR. BANERJEE: None of this concerns the primary side then? Okay.

MEMBER WALLIS: Because of the materials that are used there, is that it, really?

MR. MAKER: Well, yes. Once you get to 1 and a quarter.

MEMBER SIEBER: Single phase flow.

MR. MAKER: Yes. And you need moisture fort his to occur.

MEMBER WALLIS: Moisture isn't

necessary. You've got this in the feedwater line.

MR. MAKER: Sorry. Yes.

MEMBER WALLIS: I mean --

MR. MAKER: And there's also a temperature --

MEMBER WALLIS: Okay. I guess --

MR. MAKER: Well, some things like velocity, as you increase velocity you would expect corrosion rate to increase. There are other effects like temperature where there's a peak around 300 degrees fahrenheit and then beyond that then it start decreasing.

MEMBER WALLIS: Well, CHECWORKS is well established, and it's updated from time-to-time. So throughout industry, isn't it? This is why the NRC has stopped --

DR. BANERJEE: Also I suppose from a safety point of view this is not incredibly significant.

MEMBER WALLIS: Right.

MEMBER SIEBER: Not safety related.

MEMBER MAYNARD: The NRC does perform periodic inspections at the site on the flow accelerated corrosion program.

MEMBER SIEBER: Sure.

MEMBER MAYNARD: So it's not something that's just left out.

MR. MAKER: Plant audits, yes.

MEMBER MAYNARD: Yes.

MR. MAKER: So following on that idea, the importance of the inspection, this is really their -- a key to their program is ultrasonic measurements at repeatable locations to develop corrosion trends. And therefore, the combination of the required thickness of the components, the measured thickness and the corrosion rates are the key to future inspections and replacement repair decisions. And the CHECWORKS computer program is one tool in managing this program.

Next slide, please.

So they are updating the models. I've done that for the EPU. It does predict some increases in corrosion rates in some cases, decreases in others.

In cases where there's a large increase, it happened to be a system with a very low corrosion rate to start with. And that was an example Mr. Grabski showed.

So considering all these things, we concluded that their program will continue to manage the flow accelerated corrosion effectively after the extended power uprate.

Next please.

Address steam generator tube inservice inspection. Our guidance here is some -- we have standard review plans on materials and also for inspection we're focused mainly on the NEI 97-06, which also refers to the more detailed EPRI steam generator program guidelines. And as you've heard, the steam generators in Unit 1 were replaced.

There are two key materials upgrades; the thermally treated Alloy 690 tubes and also the stainless steal tube support plates, which these two things have a big effect on types of degradation that are observed and the rates of degradation, initiation and propagation. There are also some additional design factors like the shape of the holes in the tube support plates, the type of the antivibration bar design. And all of these are major improvements in steam generators.

Now the temperature, and the temperature is one of the key parameters in causing degradation. That will remain within the range seen at other plants that have 690 tubes.

There is a possibility, as you

discussed, in tube vibration and wear. And there's been an evaluation that the likelihood for wear is low. But for our purposes we're looking at the fact that if there is wear, that is captured in the tube integrity program. That the inspections will see that they're required to evaluate that and monitor that in their operational assessments and their--

MEMBER MAYNARD: Has Beaver Valley either made their tech spec changes or committed to make the tech spec changes for the Generic Letter 06-01?

MR. MAKER: They have an application in house now that being evaluated.

MR. KAMMERDINER: If I could add something. This is Greg Kammerdiner from FirstEnergy.

We have submitted the license amendment request to adopt TSTF449 for both units.

MR. MAKER: So we're concluded for Unit 1 that their program will continue to manage degradation at uprate conditions.

Next please.

For Unit 2 they have the original steam generators with the milled annealed Alloy 600 tubing and both carbon steel and Alloy 600 tube support structures. The existing degradation mechanisms include several forms or several modes of stress corrosion cracking and also some small amount of antivibration bar where the cracking initiation and growth rates could increase based on the small temperature increase and also increases in flow and potentially sludge accumulation at EPU conditions. However, these changes are relatively small and still will remain within the experience we have at other operating plants. And we don't see this as a -- it will not degrade in anyway their ability to monitor, to detect and monitor degradation at uprate conditions.

And we also note that these steam generators have a couple of design features, improvements over a lot of the Alloy 600 plants, such as the heat treatment to stress relieve small radius U-bends and also shop pinning in the portion of the tube within the tube sheet. And these are things which are shown to retard the initiation of stress corrosion cracking.

The AVB wear rates for Unit 2 are measurable but low. But as with Unit 1, again, there are inspections performed to measure this and evaluate it.

We don't expect with these small changes and conditions any new forms of degradation to emerge as a result of the uprate. But, again, we're satisfied that their program will find them and will continue to be consistent with the guidelines at uprate conditions.

MEMBER SIEBER: I think one of the big factors is the chemistry control of feedwater. And Beaver 2 should do much better than Beaver 1 because it has a polisher, it has 1 years less life even though the capacity factor is better. And generally there's been good careful control of the chemistry. So I would expect to see lower rates of degradation than Unit 1 experienced through its lifetime.

MR. MAKER: Thank you. Yes. The importance of water in chemistry is really important.

MEMBER SIEBER: That's the key factor in my opinion

MR. MAKER: Next, please.

The steam generator blowdown system helps steam generator tube integrity by controlling the quality of the secondary coolant. The blowdown flow rates are not expected to increase as a result of the uprate because they're determined by some parameters that are not going to be effected. There is a repositioning of flow control valves due to decreased pressure. This will reduce the maximum achievable flow rate, but not be require. It will not reduce it below what's required.

So we conclude that this will not have an effect on the ability to remove impurities from the blowdown. And we also note here this is a system with potential for flow accelerated corrosion and it is in their FAC program.

Next please.

Chemical and volume control system. Several functions related to the water inventory and quality for the reactor coolant.

The heat exchange temperatures, heat exchangers are one of the key components. There are some slight changes in temperature increases and decreases, but they stay well within the -- well below the design values. And the heat exchanger pressures are not changing as a result of EPU.

Boration requirements continue to be met. And letdown flow rates, charging rates and nitrogen-16 delay times are not being affected significantly by this.

So, again, according to our Standard

Review Plan we concluded that this will be acceptable at EPU conditions.

Finally on coatings. Unit 1 coatings were specified according to the ANSI standard. We're evaluating compared to -- we have a Reg. Guide 1.54, there are ANSI standards that are called out in that. And we have a Standard Review Plan 6.1.2 on coatings.

Unit 1 coatings were specified according to ANSI N101.2. When Unit 2 coatings were specified, we now have the Reg. Guide which also referred to 101.2 as well as the newer ANSI standard on the quality of coatings.

And the licensee provided us with their uprate environmental parameters compared to the qualification test values for normal and design bases accidents showing that their bounded by those qualification values. And so we expect no effect on the adhesion or the degradation of those.

CHAIRMAN DENNING: I mean if there were any issues here in the painting areas, I don't think they're EPU issues. But I'm just curious, did you talk to management of these units about what the status is of their paints, whether there is observable flaking occurring in areas and potential problems there?

MR. MAKER: I didn't as part of the EPU. And I talked to our GSI-191 team members who are evaluating their coatings. Well, the debris issue which includes coatings. But they were not able to tell me the status of coatings yet.

CHAIRMAN DENNING: Okay.

MEMBER WALLIS: Well, it says coating failures are identified by inspection. I'd be curious to know have there been coating failures.

MR. MANOLERAS: Yes. This is Mark Manoleras, Beaver Valley, FENOC.

I own the coatings program and the coating engineer works for me. Our containment coatings actually have been in very good shape. If we identify a deficiency, it's put in our corrective action system. It's evaluated by that coating system engineer and then it is repaired.

We've had outside people come in and take a look at our coatings in response to the GSI-191 to make sure that what we believe is what the outside experts also believe. And we've gotten very good feedback on that, on our coatings, our containment coatings.

MEMBER WALLIS: Have you actually had to

replace some coatings?

MR. MANOLERAS: We've had to make very minor repairs to some coatings in containment.

MEMBER SIEBER: Those are typically scrapes --

MR. MANOLERAS: That's correct.

MEMBER SIEBER: -- as opposed to force or lack of -- somebody runs a cart into the wall, you can scrape.

MR. MANOLERAS: That's correct.

MEMBER SIEBER: And you have to repair that.

MEMBER WALLIS: So it's that kind of thing rather blistering or --

MEMBER WALLIS: Right.

MR. MANOLERAS: That is correct.

MR. MAKER: Okay. That concludes my presentation unless you have any further questions on these five topics.

CHAIRMAN DENNING: I think we don't. And I think Mr. Stubbs could now continue with the next presentation.

MR. MAKER: Thank you.

MR. STUBBS: Good morning. My name is Angelo Stubbs and I'll be discussing the review of the balance-of-plant systems.

Next slide.

Okay. In conducting our review we utilized Review Standard RS-001, which is a Review Standard for extended power uprates. And in general our review scope covered the balance-of-plant mechanical systems contained in Matrix 5 of the standard.

Scope of the BOP systems included over 20 systems, 6 major areas of review, the first of which internal hazards for which reviews were performed for the EPU impact on flood protection, equipment of floor drains, the circulating water system, missile protection, the turbine generator and pipe failures.

The second area, fission product control included reviews on the fission product controlling systems in the structure, the main condenser evacuation system and the turbine gland seal system.

For the next area, component cooling and decay heat removal we reviewed the spent fuel pool cooling and clean up system, service water system, react water cooling system, ultimate heat sink and auxiliary feedwater system.

Next slide.

The next area of review balance-of-plant included review of the main steam, main condenser, turbine bypass and consondate and feedwater system.

And the final two areas was the waste management system, which included gaseous liquid and solid radwaste and then the emergency diesel fuel oil storage and light loads were also reviewed.

In addition to our review of the systems I just mentioned, the staff also reviewed test considerations for certain BOP systems.

Next slide.

The Staff focused under review of auxiliary systems for which increased heat loads associated with the uprated plant might pose an increased challenge to the systems. The systems included the spent fuel pool coolings, the service water and ultimate heat sinks, auxiliary feedwater system and condensate and feedwater system.

In regards to the spent fuel pool cooling system, the Staff determined that the licensing bases evaluation, that is the current licensing bases evaluation which was performed at the power level of 2918 megawatts will be bounding for the EPU plant. But service water system and increasing the heat loads was not to have a significant increase in fact on the system. And they stable within the design temperatures of the system.

The Ohio River is the alternate heat sink for both of these plants and this capacity far exceeds the shutdown cooling and accident heat load requirements for the Beaver Valley units. And power uprate doesn't effect the temperature in that water for this.

The auxiliary heat water system is a system which required increased flow as a result of EPU at both units. In addition, Unit 1 has undergone a modification to add limiting flow venturies. And I'll discuss the EPU impact on these systems a little later when I address modifications that effected the BOP review.

And the condensate and feedwater system, there was minor modifications of the regulating valves. But the licensee evaluation showed that the condensate pumps had sufficient margin to operate at the EPU power and that sufficient flow could be provided to the system.

In addition to that the parameters of flow, pressure, temperature parameters will be monitored during the startup so that will help verify the performance also.

Next slide.

The modification. The modifications made to the balance-of-plant. These are I'd like to talk a little bit about. Take a few minutes to talk about.

The first was modifications to the high pressure turbine and the second is a modification to auxiliary feedwater system at Beaver Valley 1.

Next slide.

Okay. But in the case of the high pressure turbine in both units, the high pressure turbine is being replaced with an all reaction turbine. The Unit 1 modification has already been completed. They have calculated the maximum overspeed to be 118, which is below the acceptance criteria of 120.

The Unit 2 modification has not been completed yet and will be completed prior to operation at EPU. But at this time they have done the calculations for overspeed the licensee has committed to perform the appropriate overspeed analysis to ensure overspeed protection that's acceptable. Also as part of their operating surveillance tests verifies that the proper operation of the turbine overspeed trip protection system and that -- and they do this by demonstrating that the turbine works at or below the 111 percent at that.

MR. TESTA: Excuse me. This is Mike Testa.

I just wanted to clarify one thing for Unit 2. Now the way we're going to -- we're going to do a staged power increase. The existing turbine has additional capacity to it, around 5 percent. So we're going to elect to increase the power somewhat the existing turbine. But prior to going to the full extended uprate, we will replace the turbine with the reaction turbine.

MR. STUBBS: Okay. The auxiliary feedwater system, for this system in Unit 1 they're adding cavitating venturies. They're installing that as a modification to Unit 1.

At EPU the auxiliary feedwater pumps, which are now being credited for the feedwater line break and the loss of normal feedwater events, which is something that the current plant doesn't do.

Unit 2 licensing bases already credits these to AFW pumps. So this isn't a change to Unit 2. It's only a change to Unit 1. We did look at that. And the total required flow for the auxiliary feedwater system will be able to be met by any of the two pumps available out of the three that services that system. And there will be sufficient capacity for it to perform this intended function.

And the technical specifications, as I just mentioned, requires three alternate auxiliary feed pumps to be operable. And so this allows us to have a single failure and still require it to -- for the two events, the loss of normal feedwater and heat feedwater line break.

Next slide.

Okay. In summary, Staff finds that the proposed EPU to be acceptable with respect to the balance-of-plant areas based on:

The evaluations that was performed that we reviewed;

The commitments made by the licensee, and;

The tests that they will be performing.

So, is there any questions.

CHAIRMAN DENNING: Are there any questions? No.

Thank you very much.

MR. STUBBS: Okay. Thank you.

CHAIRMAN DENNING: Now what we'll do is we'll take a 15 minute break so we can prepare ourselves for the risk assessment presentations. And we'll be back by the clock on the wall at 10:00.

(Whereupon, at 9:49 a.m. off the record until 10:04 a.m.)

CHAIRMAN DENNING: We'll now come back into session. And our first presentation will be on risk analysis and its impact.

MR. KELLER: Good morning. My name is Colin Keller. I'm a supervisor of the PRA Group at Beaver Valley.

With me here today also is Bill Etzel to help answer any questions that the Subcommittee may have.

A little bit about myself. I've been in nuclear power for 24 years now at Beaver Valley, starting at the Shippingport Atomic Power Station and working through other engineering assignments through Unit 2 startup, equipment qualification and the last ten years I've been involved in PRA.

I'm here today to discuss the Beaver Valley EPU PRA models, one for each unit.

Next side.

And I'd like to talk about the elements

of the Beaver Valley model that were reviewed as part for this uprate. And also to talk about the resulting changes in core damage from these reviews.

Next slide.

The first element we reviewed was our initiating events. We found that from the extended power uprate there were no new initiators identified and also there were no significant increases in our initiating event frequencies as a result of the power uprate.

We also did a review of our success criteria. We used the MAAP code to perform these analyses to establish our success criteria. Also included setpoint changes in there due to containment conversion and new pump curves that were put in.

We found that new accident sequences were identified as a result of the power uprate.

We went on to review our component and system reliability. Comprehensive reviews of the equipment were performed. We found that systems will operate within their allowable limits. There was on the PRA failure rates or results. We will continue to use our existing monitoring programs to account for any additional system wear using

Maintenance Rule MSPI, flow accelerate corrosion.

We expect that our future model updates will capture any initiating event or equipment failure rate changes.

We also performed reviews of our operator response times for our human reliability analysis. The MAAP analysis was used to determine operator action times that are available.

Higher decay heat did reduce times for some of these operator actions.

The most important impacts were:

For operators to start aux feedwater given a solid state system protection has failed and no SI signal present;

Operator initiates a bleed and feed, and;

And there was a reduction in time to recover from a loss of shutdown cooling due to reduced inventory.

This is a listing of Unit 1's five most important operator actions. You see there was a reduction in time for two of those actions from the pre-EPU to the post-EPU. And as a result of that, there was also an increase in their human error probability for both of those actions.

The following table --

CHAIRMAN DENNING: No. Let's stick a little bit with this. You were done with this table, let's spend a little bit more time on the table.

MR. KELLER: Certainly.

CHAIRMAN DENNING: So the first item and the last time are the only ones where you have a significant change in your human error rates, is that right?

MR. KELLER: Yes. And as you can see, those are also the ones that saw a reduction in operator action time.

CHAIRMAN DENNING: Now this initiating feed and bleed, there's really a major time, difference in time, isn't there? Between 78 minutes and 29 minutes, is that right?

MR. KELLER: That's correct.

MR. ETZEL: This is Bill Etzel from FENOC.

Yes. In the pre-EPU case that was done with a hand calculation and it was based on steam generator dryout. For post-EPU feed and bleed was based on a 13 percent wide range level in the steam generators.

CHAIRMAN DENNING: So the big difference is really a matter of --

MR. ETZEL: Yes, in setpoint levels.

CHAIRMAN DENNING: Okay. Now I'd like to spend just a little bit of time on each of these, if you would. And give us some -- and that doesn't necessarily have to be a lot. But let's start with the first one here.

The first is starting the auxiliary feedwater system when you have no safety injection. And it does look like the 43 minutes certainly seems a substantial period of time to be available for that. You say the confirmation as it was simulator observation. So tabletop and simulator observations. So you've run through this in the simulator at post-EPU conditions?

MR. KELLER: That's correct. And George Storlis is here. He will speak to that.

MR. STORLIS: Yes, I'll speak. My name is George Storlis. I'm with FENOC.

And operationally we train extensively in the simulator environment. Both Unit 1 and Unit 2 have separate simulators, have a lot of exposure to simulator time.

One of the key elements of any failure

of solid state is manual backup by the operator and the supervisors that stand behind the team as part of the simulation. And 43 minutes is an extensive period of time, as you pointed out, for diagnosing a failure and then ultimately responding to that failure with manual actions. So I'm quite confident that we can make that 43 minutes.

CHAIRMAN DENNING: Okay.

MR. STORLIS: Probably in the realm of 2 minutes or less.

CHAIRMAN DENNING: Although you did have a big change in the human error -- I mean a big change in the human error probability. But I won't get into the details of that. I don't care.

Now let's look at, the second one obviously that's not an issue is the 24 hours.

The next is this portable diesel driven fans to cool the emergency switchgear rooms.

MR. STORLIS: Switchgear ventilation affords a rather large heat sink in that area. The portable ventilation is established to enhance existing cooling. And in the absence of cooling you have a period of time to set up and establish that flow.

MEMBER MAYNARD: Is the equipment pre-staged?

MR. STORLIS: The equipment is available and staged in a brigade area. And it's available.

CHAIRMAN DENNING: What about this, this fourth one? Can you describe that one to me? The reactor coolant pump trip, what's happening here.

MR. ETZEL: This is Bill Etzel from FENOC again.

Yes. That's just a simple reactor coolant pump trip on CCW, which is our component cooling water. And component cooling water supports thermal barrier cooling along with motor and cooling to the motors of the pumps, the reactor cooling pumps. So therefore we assumed that you have five minutes to trip the pumps with that, otherwise you would get an increased RCP seal LOCA due to high vibration.

MR. STORLIS: Again, this is an area where operator training is repeated over and over and over again to identify the absence of cooling water flows to the coolant pumps and the need for the five minute window to shut the pumps off to preserve the pump's condition.

MEMBER SIEBER: It seems to me you actually had an event like that at one time. Is that correct? Where you lost seal coolant?

MR. STORLIS: We did have an event where in loss of an emergency bus did transcend itself into a loss of thermal barrier cooling. And the pump was managed immediate to that and seal injection was reapplied in the pump.

MEMBER SIEBER: You actually didn't trip the pump, you reestablished the flow?

MR. STORLIS: Seal injection, that is correct.

MEMBER MAYNARD: This is I think a pretty common requirement or guideline for all the Westinghouse --

MR. STORLIS: That is a true statement, sir.

MEMBER MAYNARD: -- seals.

CHAIRMAN DENNING: Let's go to the next table them.

MR. KELLER: Okay. The next table is similar and is a listing of the operator actions for the Unit 2.

CHAIRMAN DENNING: Okay. Let's see, are there any here that are particularly -- okay. Well, let's start at the bottom one, the -- let's see. This is manual trip after the solid state protection system fails to automatically actuate reactor trip. So this is --

MR. KELLER: Directly from the bench port.

MR. STORLIS: Again, this is George Storlis.

The operator identifying conditions as displayed on what we call our first op panel. It enables early diagnoses of the need for trip along with a validation with the existing instrumentation. And the operator's license responsibility and legal responsibility to bring that reactor off line on manual action.

CHAIRMAN DENNING: Okay. Let's see --

MEMBER KRESS: Did you use a human error model to get these probabilities?

MR. KELLER: Yes. We were using the HRA Calculator?

MEMBER KRESS: HRA Calculator. That's the EPRI --

MR. KELLER: That is correct.

MR. ETZEL: We just switched to the HRA Calculator.

Bill Etzel, FENOC.

When we did this analysis we used the

SLIM methodology, success likelihood index methodology.

CHAIRMAN DENNING: Let's see --

MEMBER KRESS: And the confirmation with the simulators tabletop was just to show that you did it within that.

MR. KELLER: Ensure that we would be capable of performing those actions with the times that we don't have.

CHAIRMAN DENNING: Now why do you say tabletop there and simulator? Isn't this something that you would have verified with the simulator, validated with the simulator.

MR. ETZEL: This is Bill Etzel from FENOC again.

Yes. We were going through an update on our PRA model at Unit 1. And like Colin said, we were using the HRA Calculator. So we waned to -- since we were changing methodologies, we wanted to validated all our human actions. So we had simulator runs for the Unit 1 PRA model update. Similarly, when we go through the Unit 2 update sometime later this year, we will also do some simulator benchmarks.

MEMBER MAYNARD: But many of these are

things that you're doing as part of normal ops training anyway, aren't you?

MR. STORLIS: That is correct, sir.

MEMBER MAYNARD: This last one in particular, that's one of the first things you do when you have an issue is to check it and there's more than one person doing that, too.

MR. STORLIS: And that is absolutely correct. We're practiced on these in the simulator environment repeatedly.

MR. SENA: Again, this is Pete Sena. The indications available to the operators at Unit 1 to take the actions such as manually tripping the reactor in the event of a first out indication for the need for a trip is virtually identical at Unit 2. So the actions are the same, the training is the same and the indications are the same. So you can translate the simulation walkthrough that we've done at Unit 1 into Unit 2 through the tabletop method and be confident that the times are identical.

CHAIRMAN DENNING: Yes. It is interesting, though, that you seem to have some significant differences between the two units as to what the risk important operator actions are, or am I misinterpreting the similarities here? Is that true?

MR. KELLER: There are some differences between the units, yes.

MEMBER WALLIS: These are all errors of omission where the operator fails to do something?

MR. KELLER: That's the probability that we've failed to accomplish that action.

MEMBER WALLIS: Do you somehow put in potential errors of commission by misdiagnosing something and doing the wrong thing? Does that appear in your PRA at all.

MR. ETZEL: This is Bill Etzel from FENOC.

Mostly they are failures of omission in that he does not perform this action as opposed to doing the wrong action and making things worse.

MEMBER WALLIS: Are there some items of commission that would be affected in some way by the power uprate in that there will be a little more going on or more likelihood to make a mistake or something like that? I don't know you assess that, but conceivably in could be a context which is more likely to produce an error.

MR. ETZEL: Yes. This is Bill Etzel again.

That's a possibility and hopefully through the simulator training and just normal time in the control room will help prevent that.

MEMBER WALLIS: Fix that up during simulated training. You observe and see if as a result of the EPU there's more tendency to make some mistake, and then you correct that in some way? Is that the way you find it? You do it by training in the simulator?

MR. ETZEL: Yes.

MR. STORLIS: And this is George Storlis.

With regards to the structure of the OP, operating procedures, the team concept in the control environment, the identification of a potential error being made is identified and corrected before the committing of the act. So from an operating perspective the confidence in the team, the confidence in the training, the confidence in the practice of simulation and EOP network provide a high level of assuredness of proper actions.

MEMBER MAYNARD: The EOPs are also fairly good that even if a mistake is made or there's multiple things going on, getting you back, prioritizing and taking care of the issues.

MR. STORLIS: That's correct. The response not obtained columns and so forth that structure a pathway to success is very high.

CHAIRMAN DENNING: And I think if you identified in your simulator training a place where people were making errors of commission, then you'd correct something rather than putting it as a probability failure in a PRA.

MR. KELLER: That's correct.

CHAIRMAN DENNING: So it's hard to identify them, Once you do, then presumably you'll fix them.

MR. KELLER: Yes. You want to reenforce the training so we would make sure that we'd meet these times.

MR. STORLIS: Either in robust barriers and the like to assure that if there is a likely error condition that it's remedied either by physical barrier or other means.

CHAIRMAN DENNING: Okay. Proceed.

MR. KELLER: Okay. Thank you.

Next slide.

In regards to the operator response times, we did do a validation of the operator times to complete these actions through combinations of tabletops, discussions of simulator training or observations. And the operator actions with small amounts of time available can be performed within the time that is available.

MEMBER WALLIS: "Can" is a big --

MR. KELLER: I'm sorry?

MEMBER WALLIS: "Can" is a big word. I mean can with probability of zero or one? You think it can be performed with high probability or something.

CHAIRMAN DENNING: Well, he has exactly the probabilities on this table.

MEMBER WALLIS: He does, I know. But --

CHAIRMAN DENNING: These are three significant figures.

MEMBER WALLIS: I know. So it's really it will be performed or likely to be performed.

MR. KELLER: Likely to be performed. That's probably yes.

MEMBER WALLIS: Right. There's some things I can do, but without much probability.

CHAIRMAN DENNING: Likely would be a very PRA term.

MR. KELLER: I understand. Likely to be performed.

Next slide.

We also did a review for shutdown risk conditions. We found the EPU has no unique or significant impacts to the shutdown risk. There'll be no changes to shutdown operations to our safe shutdown risk assessments.

Next slide.

Summary for Unit 1 is shown here for the total core damages from pre-EPU to post-EPU and with a breakdown of internals, externals and fire and also it shows the differences for the total LERF. And the changes in risk are well within the guidance provided by Reg. Guide 1.174.

MEMBER MAYNARD: One new piece of equipment that you put in was the main feed isolation valves, How was that treated? Did that end up with positive credit, negative credit relative to the PRA. Because a new piece of equipment --

MR. KELLER: Yes. You do have some additional failure probabilities with that and also with the cavitating venturies. There is a probability that they could plug. But overall for the sequences, and Bill correct me, where main feedwater was involved there was not a huge impact from those additional failure rates.

MR. ETZEL: That is correct.

MEMBER MAYNARD: On the main feed isolation valves are you using an existing design that's been out there proven or is this --

MR. ETZEL: This is Bill Etzel from FENOC.

We have these similar valves installed at Unit 2, so we use their failure rates and apply them to Unit 1.

CHAIRMAN DENNING: Now let me ask an embarrassing question.

MR. KELLER: Yes, sir.

CHAIRMAN DENNING: Maybe an embarrassing question. And that is, you know, we recognize that there are changes in risks that aren't quantified by the way we treat CDF and LERF, particularly as far as radionuclide inventory is concerned. I mean, the risk is going to increase with no changes in CDF and LEFT, you're going to see there is a true increase in risk of at least a percent associated with --

MEMBER KRESS: Sixteen percent.

CHAIRMAN DENNING: -- this.

MEMBER KRESS: Two plants.

CHAIRMAN DENNING: Two plants. Well, I'm

not sure that that's still eight percent per, Tom. But in any event, we have had other applicants who have said okay, we want to make sure that the risk is not increased, and so we look to see what aspects of our PRA indicate things that we could fix that would actually reduce the risk or maintain the risk.

And I realize, of course, you changed the generator on Unit 1 and there's been probably a decreased risk associated with that. But as far as just looking at the major contributors to risk and recognizing the potential benefit that's associated here that certainly is worth doing, but did you look to see are there things that at this particular time we might change so that indeed we're not increasing the risk?

MR. KELLER: Yes. We have looked and we actually have some recommendations based on that. We've looked at things like potentially going out and adding additional methods for RCP seal injection. There was a recommendation also to, I believe it was restructure an EOP to gain some benefit towards large early release frequency.

And, Bill, there were two other modifications for each unit we were also looking at?

MR. ETZEL: This is Bill Etzel from

FENOC.

Yes. We also looked at increasing seismic ruggedness. We have at Unit 1 block walls on our emergency batteries. So we're looking at increasing seismic readiness of those block walls.

Also putting some fire barriers around our HVAC fans in the cable vault and spreading area.

CHAIRMAN DENNING: And has management agreed to any of these upgrades or made a commitment to these at this time?

MR. KELLER: At this time our plans to take those to our plant health committee at site and to get them evaluated and go forward from there. See if they'd --

CHAIRMAN DENNING: What's the committee you said?

MR. KELLER: Called the plant health committee.

CHAIRMAN DENNING: Plant health committee?

MR. MANOLERAS: Yes. This is Mark Manoleras from FENOC.

Our plant health committee is comprised of basically the management team at the site. Each project is presented to the plant health committee and it's weighed on its benefit and risks to the station and then will be implemented in course; ranked and implemented in course.

CHAIRMAN DENNING: Yes.

MR. ETZEL: And this is Bill Etzel from FENOC.

We did present the alternate RCPC seal injection system to the plant health committee already.

CHAIRMAN DENNING: And has a decision been made on that at this point or is that --

MR. ETZEL: Yes. We have had positive feedback on it.

CHAIRMAN DENNING: Yes.

MR. KELLER: A decision was made whether to go and install it at this time.

MR. ETZEL: Yes. The decision was made was that we were going to take a look at options to actually implement those options and then estimates will be performed on those options. We will go to our next committee, which is our technical oversight committee, which takes a look at the technical robustness of the options and how those will be implemented.

So it's well along in the process to be

targeted.

CHAIRMAN DENNING: What are the criteria that the committee uses to decide whether they would undertake a safety improvement that effectively isn't providing economic benefit?

MR. ETZEL: Yes. We actually have a very detailed rating system. We went out and benchmarked the industry and took a look at basically industry best practice. And actually one of the significant contributors to identify a project selection would be an increase or decrease in risk. We actually have a very large portion of our process will actually look at the change in CDF. So it's actually a big contributor to selecting a project to be implemented.

CHAIRMAN DENNING: You know, that still didn't help me very much. I mean, I'm talking about some things here where there's no economic benefit to the plant, or at least the economic benefit isn't obvious of some of these safety related improvements that could reduce risk. And so the question is under what conditions would the plant management say, well, it really -- I'm willing to invest some money here to reduce the risk even though I'm not going to see an economic payback and there's no regulatory requirements.

MR. ETZEL: Yes. I'm sorry if I didn't answer that clearly. A reduction in that risk is one of the key contributors to ranking a project. It is probably one of the top three contributors to ranking a project.

CHAIRMAN DENNING: Thank you.

MEMBER KRESS: As a bit of a follow on to this question, does your PRA system have the capability to do a level 3 analysis?

MR. ETZEL: This is Bill Etzel again.

Currently we do not. We just have level 1 and level 2.

MEMBER WALLIS: With a follow up question again. I understand that management looks at decreasing risk as a criterion for endorsing a project. Presumably there's something on the other side of the balance which is the cost of implementing this. And I just wonder how much your management is willing to pay? Do they have some sort of a figure that says we're willing to pay so much for so much decrease in risk? Is there some kind of an economic that's understood in the plant or is it not? You don't have to give me the figures, but it seems to me in the end its cost benefit that's got to rule in the decision.

MR. SENA: This is Pete Sena.

When we go through the plant health committee there's a detailed ranking form, as Mark was speaking towards, as far as how we score a particular project. Some of the other criteria may be, for example, does the modification result in in improvement in radiation dose to folks doing work on the station. Other criteria would be, you know, a change in personal safety, a change in equipment reliability. So there are many factors.

Those factors are then accumulated and tabulated. And that is then weighed against all the other modifications that are proposed.

Now, out of a year we will go through and we will pick, perhaps, our top 12 or 15 projects to go implement to look a year ahead. But, again, we do have limited financial means, as every other utility does. So we have a specific set budget. But the ranking criteria does not apply to the initial cost estimate. It would then be categorized against all the other mods. And we have X number of dollars and how many mods do we want to do with that X number of dollars.

MEMBER WALLIS: And so you have to spend

your budget?

MR. SENA: We would spend our budget, correct.

MEMBER WALLIS: So there is no trade-off? It's just a question of which ones do you spend it on, is that it? That was an interesting economic viewpoint.

MR. SENA: Well, again --

MR. MANOLERAS: Well --

MR. SENA: Go ahead.

MR. MANOLERAS: This is Mark.

Again, we want to weigh all the factors for the selection of this modification. We may want to increase equipment reliability in an area, we may want to increase personal safety. So we do weigh all those facets when we select the modification packages.

MEMBER KRESS: Just out of curiosity, how far away is Pittsburgh from Beaver Valley's plant?

MR. MANOLERAS: It's approximately 30 miles.

MEMBER KRESS: Thirty miles?

MR. MANOLERAS: That's correct.

CHAIRMAN DENNING: Proceed.

MR. KELLER: Thank you.

The next slide is a similar summary for Unit 2 showing the same changes. And, again, the changes in risk for both CDF and LERF are below the thresholds for Reg. Guide 1.174.

MEMBER WALLIS: Reg. Guide 1.174 also gives you no incentive decreased risk.

MR. SENA: And, Dr. Wallis, if I may just go back to how we look at various projects we may do. One example to speak towards, for example, is we installed N16 monitors at Unit 2. We had them previously installed at Unit 1. But, again, this was a benefit to the station. Not a production benefit, but a safety benefit so that operators would have a key prompt indication of a potential tube leak. So, again, that is an excellent example of a mod that met our criteria to move forward with.

MEMBER WALLIS: Thank you.

CHAIRMAN DENNING: Yes?

MR. KELLER: Okay. And summary, all the PRA model elements were reviewed for impact and found that the increase in risk due to the EPU for both Unit 1 and Unit 2 does meet the acceptance criteria. There were small changes in operator times that were available for some actions, and additional equipment that was installed had a small impact on overall risk.

CHAIRMAN DENNING: Let me just state for the record, I mean I think it's fine for you to compare with Reg. Guide 1.174, but its applicability to power uprates is somewhat questionable. And I think that the way the risk analysis was used in the review is really in a slightly different way than applies 1.174 to a change in the licensing.

MR. KELLER: Since it's not a risk informed application?

CHAIRMAN DENNING: Right.

MR. KELLER: Okay. I understand.

CHAIRMAN DENNING: Well, not to say that it isn't interesting to look at.

MEMBER SIEBER: It's not a risk informed application. It's nice to have risk information.

CHAIRMAN DENNING: Right.

MEMBER SIEBER: And, for example, the PRAs the state of the art today, does not evaluate and assign risk numbers to how much margin that you're reducing.

CHAIRMAN DENNING: Right.

MEMBER SIEBER: And to me that's a significant thing, but we are not going to easily get to the point to do that. It's a tremendous amount of work. And that's probably off in the future in number of years.

MR. KELLER: That's all I have.

MEMBER WALLIS: Do you have some perspective on what's the effect of these power uprate on risk? I mean, this is a measure of safety and this is what we're here for, so we get some idea what are the consequences of an EPU. And I think that's useful. But it's not as if 1.174 is the rule that you're going to use.

MR. KELLER: Oh, agreed. But it is a measuring stick, yes.

MEMBER WALLIS: Yes.

MR. KELLER: Any other questions?

CHAIRMAN DENNING: Okay. I see no other questions. I think we're ready to move on to the staff.

MR. KELLER: Thank you.

CHAIRMAN DENNING: Thank you.

We're on the Staff's presentation on risk assessment.

MEMBER SIEBER: Risk evaluation.

MR. LAUR: Well, good morning. I'm glad to see it's still morning.

My name is Steve Laur. I'm in the NRR Division of Risk Assessment, Senior Reliability & Risk Analyst. I'm here today to discuss the Staff review of the Beaver Valley EPU risk assessment.

Next slide.

I'll give you the conclusion slide first and if that's all you want to hear, we can make this even shorter.

The licensee assessed the potential risk impacts of the extended power uprate. Our review concluded and agreed with the licensee that special circumstances do not exist that would rebut the presumption of adequate protection. So therefore, we have approved going forward with this proposed power uprate.

Next slide.

Just a reminder, I think you just mentioned this right before I got up here, but they are not risk-informed as defined in Reg. Guide 1.174. However, there is an applicable review standard 001 that basically describes the purpose for the risk information that the licensee provides.

First of all, to determine whether the risk is acceptable. But as I mentioned before, to determine special circumstances exist that would rebut the presumption of adequate protection afforded by compliance with regulations. And this is discussed in the Standard Review Plan, Chapter 19.

This has been said a few times yesterday and today, but I want to reiterate this. This is an 8 percent power uprate. The Staff has approved uprates on PWRs up to 17 percent and on BWRs up to 20 percent. And so far from the risk assessment and from other reviews we have yet to determine special circumstances.

Next slide.

One thing that's important in looking at a risk assessment using a PRA is what is the quality or pedigree of the PRA? Beaver Valley has two separate PRAs because the units were sufficiently different. These are full power seismic fire and internal events including internal flooding PRAs. And they calculate the risk matrix, core damage frequency and larger release frequency.

For other risks including other external events and shutdown risk, the licensee used qualitative risk assessment.

CHAIRMAN DENNING: Unfortunately, George Apostolakis isn't here to say what's a qualitative risk assessment --

MR. LAUR: Yes. I noted that. I appreciate that.

CHAIRMAN DENNING: That's okay.

MR. LAUR: PRA quality, these are uprates of the agency's IPE models, and in the case of the fire and seismic, IPEEE models that were submitted under Generic Letter 88-20.

They had an owners review on the internal events portion in accordance with the industry peer review guidelines in 2002 and they've incorporated the resolutions from those comments.

The seismic fire PRA models, we don't have an equivalent industry peer review process or standards. However, they were reviewed by the consultants that did the work. I take that back. They were reviewed by consultants when the IPEEEs were performed. And the NRC in the staff evaluation report found them acceptable for meeting the Generic Letter 88-20 purpose.

And so the conclusion that I made from all this is that the PRA is of sufficient scope, quality and level of detail to support this application.

We also conducted a very focused onsite

audit of the licensee's PRA last October. There were several purposes. One was to understand the risk of the EPU taken by itself. A second purpose was to check the quality of the PRA and the risk assessment that was done using the PRA and to understand and clarify some of the RAI responses in an onsite manner as opposed to multiple back and forth on the docket.

Let me go to the key findings. The key findings was that the licensee up to that point had not assessed the risk of EPU by itself. There were model enhancements and methodology changes and then modifications to the plant that were unrelated to EPU that were included in the post-EPU model which made the delta risk assessment not apples-to-apples comparison.

Also, as a result of the audit we identified the need to explain some apparently anomalous MAAP results.

Coming out of the audit the licensee actually identified a MAAP error and reperformed and resubmitted quite a bit of the HRA timing analysis. They also submitted a risk assessment that was more of an apples-to-apples comparison pre-EPU to post-EPU.

DR. BANERJEE: Which were the MAAP results that had to be explained? What type of results, do you remember?

MR. LAUR: There was a reactor coolant pump seal LOCA calculation for station blackout. Correct me if I'm wrong, I know it was station blackout. I think it was RCP seal LOCA that in most of the cases from pre-EPU to post-EPU timing decreased as you would expect. In one case it actually increased. And so we questioned that. And then on the audit we pulled the thread a little more, the licensee ended up getting Fauske & Associates involved in explaining how the MAAP code works, et cetera. And it turned out the actual timing increase was due to another change, it had to do with the accumulator setpoints. And therefore, it could be explained in terms of the thermal-hydraulics, which was not my expertise, but it could be explained in the fact that more accumulator water went in during the transient.

However, in the course of researching that they discovered a modeling error in the MAAP model that required redoing.

DR. BANERJEE: Do you recall what the error was?

MR. LAUR: They had the pressurizer surge line going into the top of the loop instead of in the middle of the loop.

MR. ETZEL: This is Bill Etzel from FENOC.

Yes. on the pressurizer surge line the MAAP code we had a loop sealed model where in reality we do not have one.

DR. BANERJEE: But why didn't it show up in the pre-EPU calculation and the post-EPU. I mean, the error would have been made in both, right?

MR. LAUR: Right. The error was a preexisting error to my understanding.

DR. BANERJEE: So why did it give this anomalous result?

MR. LAUR: I can't answer that. But I know in my review when we're looking at a table of timing changes due to EPU and you see all of them going in the expected duration, a little bit shorter, and one of them going longer, it causes you to question.

But as to why that wasn't caught earlier, I don't know.

MEMBER WALLIS: But the two aren't quite so connected. Maybe the result of this lead to a review of MAAP which showed up this error; I'm not sure the two things are connect.

MR. KELLER: Yes. This is Colin Keller.

That's correct, Dr. Wallis. The two were not related. The error was found in part of the review that we did to the NRC's --

MEMBER WALLIS: You were lead to look further at MAAP and then you found something -- okay.

MR. KELLER: Yes.

MR. LAUR: Right. I didn't mean to imply that this error was causing the anomalous result.

DR. BANERJEE: So why was there an anomalous result? Then we're back to --

MR. LAUR: Well, when I say "anomalous," it's apparently anomalous --

MEMBER WALLIS: But not really?

MR. LAUR: -- but the reason for the time getting longer in this one or two scenarios, I don't remember how many there were, had to do with changing accumulator pressure setpoints and level setpoints that resulted a change in addition to or actually opposite to the change caused by power increase. So that in this particular scenario instead of the timing getting shorter, this additional water from the accumulators actually caused it to be longer.

DR. BANERJEE: So it was a legitimate-- now you accept that as a legitimate finding?

MR. LAUR: Yes. Yes.

DR. BANERJEE: But at the end of it it allowed you to -- well, not allowed it actually initiated this review of MAAP which found an error. But that error had nothing to do with this?

MR. LAUR: That is correct. And the real point I was trying to make here is that they did review the MAAP analyses and resubmit them on the docket.

The other result out of the --

DR. BANERJEE: Was there any independent check of MAAP or audit of MAAP or was this what was done?

MR. LAUR: I don't know. The audit we did was not looking at MAAP. We're looking at very focused on the licensee's configuration control process for MAAP and for risk calculations and on specific areas that we had asked in RAIs that we didn't understand. And this was one of them. But I think there were two MAAP areas, and the one they were able to resolve right away and this one took a little longer.

DR. BANERJEE: What was the other area?

MR. LAUR: I'd have to look it up. I don't recall offhand.

DR. BANERJEE: Okay.

MR. LAUR: The other result, though, we did compare the licensee's procedure for configuration the PRA to the ASME PRA standard Section 5 and concluded it was a good process. They had virtually all the elements met for practicing the configuration control by procedure.

The licensee already covered the fact that the way we tend to assess the risk is to look at the various elements that make up a PRA and say what could be impacted. And I've got these combined in a couple of slides here. But this one talks about initiating events and equipment reliability.

The EPU does not result in any new initiating events. Even in the cases where an initiating event is modeled as a fault tree model of some operating system that fails during its mission time, the equipment reliability is not expected to change either. So therefore, those initiating events would not be impacted.

And for the same reason the systems that are mitigating the accidents are not expected to change because they're still operating within their same design limits.

Next slide.

Accident sequence and success criteria. The general accident progression, accident sequence progression did not change. In other words, the event tree models are the same. Now timing may be different at EPU conditions, but you don't expect to have to ask different questions in the event tree as a result of an 8 percent power uprate. And the licensee concluded that you don't, and I concur.

The success criteria for the most part stays the same. And I just want to talk about a couple of places where it didn't.

Station blackout is impacted slightly. If you have a station blackout and never recover offsite power, you're going to have core damage somewhat earlier. That translates int the time that the operator has to recover offsite power, which translates into a higher operator action failure probability and therefore core damage frequency. The licensee did include that in their post-EPU model.

The ATWS success criteria was impacted.

Addition of the cavitating venturies on Unit 1 means you can no longer mitigate a full ATWS event because you can't get full flow out of three AFW pumps. However, the PRA success criteria didn't change. And the reasons for that is that the licensee had conservatively not credited full flow in the pre-EPU model. And therefore, the success criteria is the same. The licensee reported no change in risk.

I pointed out in my safety evaluation that that's not correct. There is a change in risk. The change in risk would be if you had taken the conservatism out of the initial, the pre-EPU, and you'd actually get a delta. But I also know to looking at the information they submitted that ATWS is less than 1 percent on both units. Therefore, the max that could be would be a 1 percent. It would not change my conclusions.

CHAIRMAN DENNING: That really is interesting, though, in terms of just looking at delta risks where, as you quite properly pointed out, that making the conservative assumptions made it look like there was no change in risk whereas in reality there was a slight increase in risk.

MR. LAUR: That's correct.

CHAIRMAN DENNING: But I agree, it's a

negligible consideration.

MR. LAUR: The design bases loss of feedwater transient was picked up by one of the other branches and brought to my attention resulted in a request for additional information on how the PRA success criteria was impacted. It turned out it was not. And the licensee submitted realistic LOFTRAN and realistic MAAP calculations to show that in a realistic analysis that the success criteria pre and post-EPU does not change.

CHAIRMAN DENNING: Now, is this the success criterion that relates to two out of three aux feedwater pumps?

MR. LAUR: Right. The PRA from a realistic standpoint pre and post-EPU you only need one AFW pump for secondary side decay heat removal. Now in Unit 2 you need two steam generators because you have small atmospheric dump valves but as far as the AFW portion, which is what has been effected by the cavitating venturies, the realistic analysis shows that it does not change.

And then the final bullet here is actually the subject of a whole other slide, which is containment accident pressure credit for ECCS NPSH positive suction head.

Next slide.

This has a potential of impacting success criteria, so that's why I put it under here. I don't know how much you want me to go over this. I thought it was pretty well covered by the Licensee and by Rich Lobel yesterday.

CHAIRMAN DENNING: Yes, I think it was. So if you just want to kind of bottom line, feel free.

MR. LAUR: The bottom line is if you remember the two graphs that were respective of calculations before and after, there's a difference of about 30 seconds to one minute when they cross zero, in which I concluded there was an incalculable risk impact, delta risk impact, from crediting the containment accident pressure.

MEMBER WALLIS: Does all this go into the PRA then? I mean you have an actual evaluation of the change in the PRA as a result of crediting this containment accident pressure?

MR. LAUR: No.

MEMBER WALLIS: You don't?

MR. LAUR: Not to my knowledge. If you look at the absolute value of a contribution to risk, in other words not the change but what it would be, and the licensee indicated that a large LOCA and failure of containment isolation for example would be 1E minus 8. I don't have their model, but what I did look at was a failure on demand. If you use a bounding value for a failure on demand of a containment isolation valve, a typical common cause failure in a bounding LOCA of frequency of ten to the minus four, you're down to ten to the minus seven right there. So you're talking about a very low --

MEMBER WALLIS: No, granting there's containment overpressure is not really something that's necessary in order to bring the risk down. It's necessary in order to meet some other requirement.

MR. LAUR: That is correct.

MR. RUBIN: Dr. Wallis, that's correct. If I could just interject momentarily.

This is Mark Rubin, Branch Chief 1.

The reason this was looked at is because of the issues related to the VY power uprate and some of the concerns on granting NPSH over pressure and the fact that the Reg. Guide -- I'm sure Mr. Lobel talked about that previously. Because the Reg. Guide is under revision, a senior NRR management asked that we reflect on the potential risk impact to see if any existed on the power uprates and that in the future it be sort of looked at quickly, if all that's required, to validate little to no risk impact. And that's why this was looked at specifically.

But the conclusion, you're absolutely correct, has no real impact in this case.

MR. LAUR: And the point was already made yesterday, but we're not granting containment overpressure. That's the existing licensing basis.

MEMBER WALLIS: There's really no change. It's been granted before and there's almost no change in the requirements, so nothing has really happened here?

MR. LAUR: Exactly. That's what we concluded.

Human reliability. I guess in keeping with every other EPU that I've heard about, this is the major impact on risk, on calculated risk. EPU has a tendency to reduce times for operators to act. The change in the HRA due to EPU is not assessed directly by the licensee. What was done instead was a sensitivity study. And the reason for that was their pre-EPU timing was, as I mentioned, based on often grossly conservative hand calculations for the time. Their post-EPU they've upgraded to use MAAP on both units.

Secondly, the method they used cannot translate small changes in timing into realistic human error probabilities.

MEMBER WALLIS: But that's just what they do, isn't it? Isn't that what they do?

MR. LAUR: That's what they do. But that's--

MEMBER WALLIS: You're saying they can't do it meaningfully?

MR. RUBIN: This is Mark Rubin again.

Yes, I think that's what we're saying. Some of the HRA methodologies, especially the earlier ones we'll grant, as Dr. Apostolakis has shown us on many occasions. The small change is in timing. The model will calculate a difference in human performance or success rate, but it's really not a meaningful -- you have no confidence really in those small changes shown.

MEMBER WALLIS: What else are you going to do? If you're asked to calculate the CDF effect, you have to use some sort of HRA?

MR. RUBIN: Yes.

MR. LAUR: Yes.

MR. RUBIN: Certainly.

MEMBER WALLIS: And you're simply saying that this isn't a very good method. I think it's a little extreme to say it's not meaningful. It's maybe the best method available.

MR. RUBIN: What is meaningful -- well, certainly it does give a quantitative result. But what is meaningful is that the techniques allow us to identify the more important actions, look at the timing changes for those and see if they're significant and let us focus in risk case.

All we wanted to point out here is that we're in the areas of uncertainty, almost in the area of noise in the small calculational differences. But we do use the technology to help us focus in on the important human response actions and look at the timing changes on those.

MEMBER WALLIS: I think you ought not to use the word "meaningful" though. That might mean the wrong thing to some people. And you're just saying that there are uncertainties and these are very small changes anyway, and all that sort of thing. But you're still doing the best you can or the licensee is doing the best he can.

MR. LAUR: That's a good comment. When I say the "methodology," as I mentioned I used the success likelihood index method, but I'm not integrating that methodology. If you have a time reliability correlation, which I think is an artifact in some ways, but as Mark said you change time, you're going to get a change. And this method has a method on the performance there's a time. If you look at the SPAR-H model, they have discreet time steps ranging from not enough time to adequate time, to excess time. And the point I'll make on the next slide goes to more with symptom based procedures, it's almost a function of can you get to that step in the procedure and then do you have an error of omission when you get to that step.

So looking at the third major bullet, the way I assessed the risk was looking at the post-EPU core damage frequency and large early release frequency recognizing that the change in those is based on natural plant changes and on a sensitivity analysis for the HRA. Okay.

And I did ask the licensee in an RAI to validate important operator actions with short time frames. You know, demonstrate they can be done. In other words, they are not precluded. I understand you "can" meaning one to zero. What I'm saying is you haven't changed the time to where something that was maybe marginal but you could do it became precluded. And they did that and nothing fell into that category of being precluded.

So my conclusions focused on, like I said, that the actual CDF and LERF and whether or not special circumstances arose.

Next slide.

The licensee showed you a top five operator actions and they gave me whole pages of them, but if you look through them and sort them by importance, I tried to summarize them in two major categories. What shows up are depressurizing the RCS and feed and bleed cooling at both units and then some manual actions to, in the case of Unit 1 start auxiliary river water pumps and align them and Unit 2 solid state protection system failure so you have to start aux feedwater pump.

The licensee, as I said, validated these and all the other ones that could be performed. But just looking at the feed and bleed actions briefly. These are proceduralized, they're routinely practiced, they're performed in the control room with one minor exception. They take a relatively short time from two to ten minutes to actually perform the tasks. And they occur in response to symptom based procedures, not just the EOPs but also the functional restoration procedures.

So the last subbullet under there is what I was trying to say. It's really more of a function of how much time you have until you get to that step in the procedure as opposed to a slight decrease in the amount of time available.

And the other two actions up there are control room actions that are simple actions.

So we concluded that there was a minimal impact on EPU risk on the HRA.

DR. BANERJEE: What about switching to hot leg injection?

MR. LAUR: I don't recall that operator action, and I'd have to defer to the utility. That might be a good one for the utility to comment on.

MR. ETZEL: This is Bill Etzel from FENOC.

We currently do not model hot leg injection.

DR. BANERJEE: But you switch, right, to hot leg injection in the log term cooling scenario, right?

MR. ETZEL: Yes.

MR. DURKOSH: This is Don Durkosh. I'll be addressing that in the next presentation.

DR. BANERJEE: Okay.

MR. LAUR: Okay. External events, we've got seismic fires and other, which include high winds. There's nothing about EPU that would increase any of the initiating event frequencies or types of initiating events from these.

The quantitative assessment, since their PRA handles seismic and fires, demonstrated that a very small impact on the risk from those. And that comes from the fact that their seismic and fire PRA models are integrated with their PRA model. So human reliability increases and plant modification increases translate and propagate through those models.

And for other external events, the successive screening methodology that was used for their IPEEE remains valid and we conclude that would be a minimal impact on risk as well.

Next slide.

I don't have as many as the licensee had, but this shows you the post-EPU core damage frequency and large release frequency using their

HRA methodology with a MAAP realistic timing and that is what I used to conclude that there was no special circumstances. These are very small changes.

The increases include the modifications and the sensitivity analysis. These small. They meet the Reg. Guide 1.174 guidelines for being small, but it's not what I based my conclusion on for adequate protection.

Next slide.

The licensee did a qualitative assessment of shutdown risk using the questions in the Standard Review Plan, Chapter 19. And we agree that the shutdown initiating events aren't impacted. Times to boil times for operator actions are slightly decreased, but minimal impact on risk.

Finally, in conclusion the licensee assessed the potential risk from EPU. We concluded the EPU does not create special circumstances that would rebut the presumption of adequate protection and therefore we found this acceptable.

CHAIRMAN DENNING: Are there any questions?

Thank you. Good job.

MR. LAUR: Thank you.

CHAIRMAN DENNING: Okay. Now we're just going to continue on and we'll get into operations and testing starting off with human factors, I guess.

MR. DURKOSH: Okay. My name is Don Durkosh. I am a senior reactor operator currently licensed at Unit 2 and control room supervisor.

I also have with me George Storlis. George brings over 30 years of operating experience at Shippingport, Beaver Valley Unit 1 and Beaver Valley Unit 2.

A little bit about myself. I have 25 years of experience in the commercial nuclear power industry. I started my career with Westinghouse working in the engineering design analysis services area. I was the Westinghouse site manager at Beaver Valley and was in the unique position of kicking off this project and working with Mike Testa from a management perspective.

And I am licensed at Unit 2 and looking forward to raising power toward the end of this year at Unit 2.

The four areas that I plan to cover are human factors, training, our test plan and overview of our test plan and touch upon large transient testing.

From an overview perspective, the human factors impact of the EPU is minimal. There's a total of eight meter changeouts from a control room perspective. Six of them are related to the fact that we're replacing our accumulator pressure indicators with a digital indicator. And we also are replacing our containment narrow range pressure indicators as part of the containment conversion project. All eight of these meters have been replaced out at Unit 1 and on the Unit 1 simulator and in the process of being changed out at Unit 2.

Coming into the EPU project we were at an advantage in that in late 2002 and early 2003 Beaver Valley Operations staff undertook a major review of our emergency operating procedures. And e have substantially streamlines our EOPs and made them consistent with the Westinghouse ERGs. And, in fact, that's a project that I also worked.

So we had a very solid foundation for coming into the final portion of the EPU project having very streamlined procedures.

In the big picture here, the procedure changes that are coming out of the EPU project are rather minimally. They're primarily: Revise operating parameters, changes in limits and revise setpoints.

One area where the EOPs were directly impacted was the addition of an attachment that will require that the control room initiate a purge following a steam generator tube rupture. However, I do want to point out that that existing attachment already exists for purging the control room for a steamline break scenario. So in a big sense, it's a very minimal impact.

DR. BANERJEE: What are those two little things there? What was that interesting stuff.

MR. DURKOSH: Go back, but don't click on it.

What they are, they are backup slides. What I wanted to do, what I have here are examples of some of the normal operating parameters and some of the EOP setpoint changes. But I looked ahead at the NRC presentation and they have much more than I have, so I don't see any value going there, if that's okay with you.

CHAIRMAN DENNING: Thank you.

MEMBER WALLIS: What we could do is check that you and the NRC have the same presentation or there's no inconsistency.

MR. DURKOSH: All right. Click on it.

CHAIRMAN DENNING: Don't click it. Don't click.

MEMBER WALLIS: We'll trust you on that one.

MR. DURKOSH: All right.

Okay. I was at the Ginna presentation so I heard your feedback, what you really wanted to focus on; those areas that were potentially impacted. So, obviously, our action time, operator action time is a key issue so I wanted to address that.

Obviously with increased decay heat the available time to perform some actions are reduced. However, I do want to point out that the basic operator actions that we have to do remain unchanged. We are not implementing any new modifications that require new operator action times. And that's unlike Ginna where they did actually implement some modifications.

In most cases our action times have either remained the same or actually been extended to improve the overall process. And I do have a couple of slides where the case is actually reduced, and I'll talk about those.

During the course of this review we also identify procedure enhancements and we have incorporated those. Most notably, we did a complete review of our fire related procedures for Unit 1 and we did a major upgrade as part of the EPU project.

And action times are being revalidated. We've already talked about some using the simulator, using walkdowns, using tabletop discussions and field timing of operator actions in the field.

I do want to take a point. Colin had mentioned operator action time relative to the PRA. And for the scenarios that I saw, most of those are beyond design bases. So it gets you pretty deep into the emergency procedures and the contingency procedures. For instance, initiating bleed and feed. There's a loss of heat sink scenario which requires us to lose all of our aux feedwater pumps, not be able to use our main feedwater pumps, our startup feed pumps, our condensate pumps. So we're basically sitting as the steam generators are slowly drying out and getting ready to wait to initiate bleed and feed. So it's a pretty extreme scenario.

Okay. The next slide.

Okay. We talked about ECCS switchover to hot leg recirc. Ken had talked about and this question just came up.

At Unit 1 the existing time is 8 hours and when we go to uprate, that time will get reduced to 6½ hours.

At Unit 2 the current time is 7 hours and that will get reduced to 6 hours.

And in addition, at Unit 2 our design bases has us switch from straight cold leg recirc to hot leg recirc and back to cold leg recirc on a periodic frequency. That time rate now is 11½ hours and that'll be reduced to 9½ hours.

I think the question came up as to what the burden or impact is. Through our simulations generally within an hour or two of a large break LOCA scenario we are back into the emergency mainstream procedure called E1. And basically we are doing our preparations looking down the road and doing our preparations.

As was mentioned, approximately one hour before we will start taking steps to make sure we have AC power to the valves in questions. If we have any jumpers that require, we have those jumpers in position. And we're briefing on what actions have to occur.

And the time frame for actually

initiating switchover, at least I looked at the Unit 1 validation efforts on the simulator to initiate hot leg recirc. Coming into the procedure we're talking a matter of minutes. So those hot leg recirc procedures are relatively streamline. You're able to get in and get out very quickly.

DR. BANERJEE: I guess the impact would be if one was wrong in determining where the switchover time should be? If it was, say, three hours instead of 6½ h ours, there's no direct measure you have here. But it's not related to the uprate, it's in general this issue of not having a direct measure for the boron?

MR. DURKOSH: I agree. It's not directly impacted by the project.

DR. BANERJEE: Yes. The amount of time difference is not significant. All right.

MR. DURKOSH: Two areas that I would like to talk about is the tube rupture and isolating aux feedwater flow and the post trip fire scenario where if we did lose aux feedwater, we would want to restore it.

Relative to the tube rupture, one of the key operator actions is to isolate aux feedwater flow. I do want to point out that all of the EPU analyses that were performed were actually based on crew simulation data collected in 2002. So we had a solid footing for the analyses going forward.

And then as part of the EPU project in late last year we ran on the simulator with the new procedures that are being proposed, we had the Unit 1 crew go through and then we validated the fact that what we had done before we were able to meet.

For Unit 2 this EOP changes are in the final stages of being identified. There were tabletops that were performed and we are planning to do simulator validation later this year.

Next slide.

Relative to the fire scenarios, key action would be if you lost aux feedwater you'd need to reestablish it. I wanted to give you a positive message here. Relative to the Beaver Valley Unit 1 the EPU project established all of the critical operator action times. The entire set of fire related procedures were revised, streamlined and the walkdowns have been completed. So that validation effort is complete.

Relative to Unit 2, about 3 years ago our fire related procedures were updated. And it turns out that because that occurred in the midst of this EPU project, the aux feedwater critical times have already been incorporated in the procedures. So there's basically minimal work to do on Unit 2. Possible that any of the lessons learned from the Unit 1 procedures may get back to Unit 2. But we're not anticipating any major changes to our procedures; they're already there. And they've already included the operator action times that are appropriate for EPU.

The next slide.

Okay. Moving on to operator training. Basically we use classroom training of our design change packages. We'll go over our tech spec and licensing requirement manual changes. We'll go over any physical changes, procedure and setpoint changes. And then also we'll do simulator focus areas where if there is a change warning, a demonstration or hands-on training, we would do that. And for instance, the Unit 1 crews had a chance on the simulator to operate the new steam generator level control program following steam generator replacement. So the crews have time to basically get accustomed to the new control setpoint.

And then we always will continue our

transient response and EOP execution training.

And for startup and shutdown, we also use just-in-time training to get the crews focused in prebrief so that those activities go smoothly.

As we discussed over the last day and a half many of the modifications have been incorporated. So crew training has been going on here for the last couple of years as modifications have been made. And they'll continue up to our EPU uprate.

We do have plant specific simulators that we use, separate ones for Unit 1 and Unit 2. And the changes that we're talking about are primarily model and initial conditions. So there's no issue about going from current plant to EPU plant other than a matter of a couple of minutes to switch over the model. I know that question was raised at Ginna. So we do not have any issues being able to switch back and forth.

Moving on test plan. This is an overview of our test plan. Primarily consists of post modifications tests which, as I mentioned, many of them have already been performed and we'll continue doing them as the mods are made.

Our low power physics testing program

remains the same. There's no change there. What we are doing is we are collecting baseline data and then using that baseline data to support our power ascension testing. And in the power ascension testing we're planning on small increments. I have a couple of slides to show you of what our current plan is.

But basically we'll use the baseline data to make data projections. We'll collect data at steady state conditions and then we'll review that day and if we have any anomalies, we'll evaluate that and identify through our corrective action program what our next step would be.

So what I wanted to do here is here's kind of a profile of Unit 1 power ascension profile. As we discussed, we just completed our 1R17 refueling outage which involved replacing the steam generators. We have started up and we are operating at a 100 percent power currently. And during the startup process we did collect baseline data at roughly 90 percent and 95 percent. So we now have the data that we can use to predict where we expect to be. Following receipt of the safety evaluation report, we plan to uprate approximately a nominal 3 percent power uprate and we'll be using the baseline data to predict where the parameters should be so that we have a method to compare.

And we expect to operate the rest of the cycle at approximately 2770 megawatt thermal.

And then coming out of the new refueling outage, we expect to return to that power level and make two small moves approximately 2.5 percent each time collecting data, evaluating the data making sure that we're comfortable and then moving up to the ultimate power level of 2900 megawatts.

I have a similar slide for Unit 2. We are currently in cycle 12 with a 2R12 refueling outage plan for the fall. Our plans here is to come out of the outage, collect our baseline data at roughly 95 percent. Come up to our current license power of 2689, which is 100 percent power and then initiate shortly thereafter a nominal increase of 3 percent up to 2770. And our plan is to operate for the rest of basically the full cycle at 3 percent uprate. And then at the following refueling outage would be the next opportunity to go ahead and incorporate the high pressure upgrade at Unit 2 and basically come out of the outage at the referenced power level and again make two small moves up to the ultimate 2900 megawatt for core license power.

DR. BANERJEE: When do you have it all with robust fuel or whatever this new RFA? I don't remember.

MR. DURKOSH: I didn't understand the question.

DR. BANERJEE: When is the core completely peopled with this robust fuel?

MR. DURKOSH: We're there already.

DR. BANERJEE: Both units?

MR. DURKOSH: That's correct. As part of our extensive planning process for this phased implementation we started five or six years ago when we began to transition to RFA fuel. So both units today as we speak are 100 percent RFA fuel.

DR. BANERJEE: Okay. Thanks.

MR. DURKOSH: The next topic, I'd like to move on, is the topic of transient testing. So what should be considered when you evaluate the need for transient testing?

One thing that is very important is to evaluate the modifications and also to evaluate the NSSS control changes. And then based on that in your test plan ensure that you have adequate coverage for testing.

So there was a detailed evaluation that

was performed as part of the license amendment and follow up RAIs. As we indicated, each of the modifications will be fully tested. And as I've already mentioned, many of the modifications have already been incorporated and we're gaining operating experience with those modifications.

In addition, design engineering did an extensive owners review of the NSSS control supporting analyses. These are the operational transients to make sure that we would not have a reactor trip during selected design bases events.

And I think the key point that came out of that is there are no controller functional or logic changes. I know Vermont Yankee had somewhat of a fundamental logic change and transient testing may have been appropriate in that case.

We have no new control schemes. And our changes are primarily limited to setpoint changes that have been optimized for EPU conditions.

The conclusion from our earlier work is the aggregate impact does not adversely affect plant dynamic response.

Next slide.

Now Beaver Valley Unit 1 given the replacement steam generators, it was important that we did monitor control systems during startup. And I believe Pete mentioned yesterday that the feedback from the operators was very positive. So our control system operated as expected and in addition we did perform, and this was an area where we thought transient testing was important, we change our valve trims out, we did change our control operating setpoints and we had new steam generators. So there was a transient test performed, and actually it was completed over the last weekend. Basically we imputed a step change and we were monitoring the controller response.

If you can go to the backup slide. I had this data provided to me over the weekend. But basically this is the new control point, a nominal 65 percent. They imputed a signal that drove the controller down 5 percent and we had minimal overshoot. And then they initiated a similar transient up with minimal overshoot. So overall the control system worked just as planned. We easily met all the acceptance criteria. And this all happened within the last few days over the weekend. So very positive feedback on the test. The test and the control modeling worked just as expected.

As mentioned, large transient testing is normally a test that involves reactor trip at some high power. At Beaver Valley any turbine trip greater than 49 percent will result in a reactor trip. As I mentioned, there are no functional changes in the NSSS controls and the supporting reactor trip functions. So we do not believe large transient testing is necessary.

In addition, the simulation code, which was LOFTRAN, that we use supported the original plant. LOFTRAN has been around a long time. So my message here is the computer code and the model basically supported the original plant design and basically all Westinghouse plant designs. The startup testing confirmed that the plant matches the model, that computer code and model supports our current operational analyses, we have used it to benchmark our simulators, we use it in our non-LOCA analysis and we use it to optimize the EPU conditions. So no further benchmark testing was deemed necessary.

And again, my conclusion is based on the technical changes there's no large transient testing that will be necessary.

Slide.

So my overall conclusions in the

operations and testing area, the key take aways are:

Our procedure changes primarily involve operating parameters, limits and setpoint changes;

The power ascension process will ensure a controlled, closely monitored, very conservative approach to our new licensed power level;

And the modification in the NSSS control changes do not alter the basic design function of those systems, nor introduce a first-of-a-kind type change that will warrant large transient testing.

CHAIRMAN DENNING: How is the auxiliary feedwater flow test did following the changes that have occurred with the venturies?

MR. DURKOSH: Actually, those venturies were replaced I think in the previous outage. But generally what we do is we have an aux feedwater flow test, an operations surveillance test. And there were predictions on what the flow requirements are. And then we have tested the system.

CHAIRMAN DENNING: Yes. And actually test it and add water to the steam generator within those tests?

MR. DURKOSH: Yes. We normally will do that in the last stages of plant startup.

MR. HANLEY: Yes. This is Norm Hanley

from Stone & Webster.

And, again, when we implemented the modifications to add the venturies, we did use the OSTs to monitor the flow to the -- we also did a very detailed calibration with the venturie itself with the vendor. We did extensive tests to make sure the calibration and the predicted flows would match. We did an OST test where we did pump water to the generator and verify those conditions. And we also did an OST on the pump to verify the pump curve was matching what we used in the analysis.

MEMBER MAYNARD: And you do this test coming out of each outage, don't you?

MR. DURKOSH: That is correct.

MEMBER MAYNARD: I mean as far as the flow test, the calibration?

MR. HANLEY: That's correct.

MR. DURKOSH: That's correct.

Any additional questions? All right. Thank you very much.

CHAIRMAN DENNING: Okay. We will go ahead and continue to hear from the Staff.

You may proceed.

MS. MARTIN: Good morning. I'm Kamishan Martin. I'm a human factors engineer in branch of

Operator Licensing.

For our evaluation we reviews procedures, training in human factors, interface --

CHAIRMAN DENNING: I think you're going to have to speak louder. And is that mike working for sure.

The room's been all changed around and so we're having some trouble with the mikes. And you really have to get right up to this mike, too, I know from experience here.

MS. MARTIN: Okay. Can you hear me?

CHAIRMAN DENNING: Okay.

MS. MARTIN: The areas we reviewed include the training and human factors interfaces between the operator and the control room and in the plant related to performance.

These are the regulatory guidelines that I use in the evaluation.

The main areas that we use that we evaluated include the EOPs and the AOPs, the operator actions that are sensitive to the power uprate, the control room alarms, the SPDS and the training program and simulator.

As the licensee stated, the changes were slight modifications for parameter thresholds and the elimination to references to the BIT tech spec. This was eliminated because it's no longer credited as a source of boron -- borated water. Sorry.

There was one new operator action that was introduced due to the EPU and that includes the control room purge. And the one change was a change to another purge of the control room dealing with the steam generator tube rupture. I'm sorry. That's a new action.

The time reductions, some of the time reductions for operator actions were due to decay heat, but as the licensee stated, most of them stayed the same. There were only a couple that were reduced due to the EPU.

In Unit 1 all of the action times were validated through the simulator and through the walkthrough in the plant.

For Unit 2 the in plant operator action times were validated, but because the procedures aren't finalized at this time they only did a tabletop review. But the licensee has committed to validating the times on the simulator once the procedures are finalized. We determined this to be acceptable because of their commitment to validated operator action times on the simulator.

This is just a table with the operator action times that were most sensitive to the EPU.

In Unit 1, as I stated, all of them were validated. But in Unit 2 there was in particular that didn't have a margin between the time available and the time it would take the operator to actually perform this. But it hasn't been validated at this time because the procedures aren't finalized.

CHAIRMAN DENNING: Now let me see if I understand. Whose evaluation of action performance time was this, the 9.7 minutes for example in this first action? That's the plant says it can be done in 9.7 minutes or somehow you guys did it?

MS. MARTIN: No, the plant said that it could be done.

CHAIRMAN DENNING: Yes.

MS. MARTIN: And they performed a validation of this because it's in Unit 1 that it could be finished in 9.7 minutes.

MR. DURKOSH: Okay. This is Don Durkosh from Beaver Valley.

The Unit 1 operator action times were validated last fall on the simulator.

CHAIRMAN DENNING: Now, why don't you stay there just a second. And that is this action performance time versus time available, I mean obviously there's extremely small margin between 9.7 minutes and 10 minutes. Is that just a conservative value as to we're 99 percent confident that it can be done within 9.7 minutes or what's the difference between the 9.7 minutes and the 10 minutes there? Can you respond to that?

MR. DURKOSH: Sure. As was discussed in the non-LOCAs presentation from yesterday, the 10 minutes was the assumed operator action time for basically terminating an inadvertent SI basically precluding additional safety injection flow into the pressurizer. And they made an assumption of 10 minutes that operator action could be accomplished. And we confirmed that we were able to do it within 10 minutes.

MEMBER WALLIS: How much time is available?

CHAIRMAN DENNING: Ten minutes. And the 10 minutes is the rough criterion that you have of you have to do it within 10 minutes, right?

MR. DURKOSH: That is correct. And where it says "Time Available/Times used in the analysis," that's the specified time, that's the target time that we're aiming at reaching.

MEMBER WALLIS: I'm assuming the time available is longer than 10 minutes.

CHAIRMAN DENNING: Well, let me put a hypothesis down and then you can tell me why I'm wrong. Suppose this action in performance time if that was the mean time that it took staff to do this, then the probability of successfully doing it within this time would be about 50 percent. And I'm sure you're not telling me that. What is that 9.7 minutes telling me? That's not the mean time to perform it. What is it?

MR. SENA: This is Pete Sena again.

Dr. Denning, if I can back up slightly. If you recall during the non-LOCA transients for the inadvertent SI, the way we went through that transient was for the design bases assumptions we bias steam generator or correct in pressurizer level an additional 7 percent high from the norm and you put in these various conservatisms.

When we go through the design bases transient, the design folks that 10 minute window to get it done. So the operating crews go through the EOPs E zero, ES1.1 for inadvertent SI and all simulator crews went through the scenario and were able to perform that action within the 10 minute time period.

CHAIRMAN DENNING: So are you saying the conservatism is within the 10 minutes?

MR. SENA: Yes. That's correct. But again when we went through the analysis the way we qualified the acceptability of the analysis was through the qualifications of the downstream piping and the PORVs and not relying on the operator action time. That's how we precluded the event from going from a condition II event to a condition III event.

MEMBER WALLIS: Well, what does the 9.7 minutes mean?

MR. SENA: Well, that is the actual time that the operating crews completed the performance in.

CHAIRMAN DENNING: All of them or --

MEMBER SIEBER: The slowest one or the average?

CHAIRMAN DENNING: -- the slowest one? Yes.

MR. SENA: I cannot recall. I believe that might have been the maximum time, but let me get back to you. Let me phone call.

MEMBER WALLIS: The average, it isn't very good.

CHAIRMAN DENNING: Right. Other than the fact there's conservatism in 10 minutes, but then we don't have a real good feeling as to how much conservatisms.

MR. CARUSO: And let's ask once again if the operators don't get it done until 11 minutes, what does that mean?

MR. FREDERICK: This is Ken Frederick.

In a realistic sense it probably means that they will be closer to overfill. In the safety analysis world that means that we'll cycle the safety valve a couple of more times.

MR. DURKOSH: So Ken gave you the analysis impact. From a simulator perspective and all the training that we have received, I cannot recall ever challenging an overfill condition on this kind of transient. We have streamlined our procedures. We can get to SI termination very quickly within 10 minutes. And normally when we would stop the simulator at that point, we're nowhere close to being overwhelmed.

MEMBER MAYNARD: I think the importance of this is whether it ends up being classified as a condition II or condition III event. In reality if they don't get it done at all, you're still covered but your safety analysis just goes into a different wonder. But it's whether this is considered a condition II or condition III event.

CHAIRMAN DENNING: In this particular case.

MEMBER MAYNARD: Right.

MEMBER WALLIS: Does this chart come from a FENOC submittal? Is this something that you put together.

MS. MARTIN: I'm sorry, what was the question?

MEMBER WALLIS: Is this chart taken from the FENOC submittal or is it taken from--

MS. MARTIN: I put this chart together from information that was in a chart that they submitted that had more --

MEMBER WALLIS: I was wondering why we hadn't seen something like this before.

MEMBER MAYNARD: I thought this was discussed a little bit yesterday.

MEMBER WALLIS: Yes, I think it was. But we seem to be seeing it a different way now than we did yesterday.

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: Now it doesn't look so

good.

MEMBER MAYNARD: Well, again, I think we had a similar discussion yesterday, though, in that what happens if the operator doesn't get the action done.

MEMBER WALLIS: Yes.

MEMBER MAYNARD: And you're still covered with your small break LOCA or whatever other analysis is covered. It's whether or not this ends up being a condition II or condition III event. And that's what was discussed with one of the NRC presenters --

CHAIRMAN DENNING: Well, that certainly is true in that first one. I'm not sure that that's true for everyone of these.

MR. DURKOSH: Well, I can address the other ones if you'd like.

CHAIRMAN DENNING: Well, why don't you go ahead and do that?

MR. DURKOSH: Okay. Sure.

So in the case of Unit 2, as I mentioned, an isolating aux feedwater on a tube rupture is a key operator action. Previously the previous analyses used 9.1 minutes. Based on the extensive simulator crew evaluations from, I think

2002, they came up with 5.5 minutes as being a very representative time to perform that action. And that was prior to our streamlining of our EOPs.

And the action performance time was tabletopped at 5 minute.

I do have some data available to me from Unit 1 which I believe it was of the order of less than 5 minutes for Unit 1 on the actual simulator.

MEMBER WALLIS: So the now column here is the time used before, pre EPU, is it?

MR. DURKOSH: That's correct. It's in the current.

MEMBER WALLIS: Okay. So the word "EPU" should disappear from the title.

CHAIRMAN DENNING: Yes. And "isolate" is that just an implication as far as offsite doses from the steam generator tube rupture or does it have more dire implications?

MR. FREDERICK: This is Ken Frederick.

Yes. Each individual action in the tube rupture procedure and the analysis associated with that is trying to minimize overfill of the generator. So for these particular cases --

CHAIRMAN DENNING: Overfill.

MR. FREDERICK: -- the goal is not to

fill up the steam generator.

CHAIRMAN DENNING: Okay.

MEMBER MAYNARD: Okay. Some of this also is to keep you from wasting water to the ruptured steam generator there?

MR. FREDERICK: Right.

MR. CARUSO: And what are the consequences of overfilling the generator?

MR. FREDERICK: If you overfill the generator, then you lose iodine partitioning, which makes the offsite doses go up.

CHAIRMAN DENNING: Okay. I think we're content with this figure.

MEMBER WALLIS: I suppose we are. And just a little bit mystified.

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: If we're just comparing columns and you say you need 2 minutes and you got 2 minutes, that doesn't really help me much.

CHAIRMAN DENNING: Now, I don't think any of these are identified as important human actions from a risk assessment. Is that a true statement? Do we still have risk people here? Are they --

MEMBER WALLIS: I think we do.

MR. LAUR: This is Steve Laur again, NRR Division of Risk Assessment.

I don't know what the relationship between the design bases accident and the PRA is. But certainly cool down -- the action to cool down is one of the risk important operator actions.

I would point out that this a design bases discussion looking at the inputs from Chapter 15 and not a risk assessment.

CHAIRMAN DENNING: Yes.

MR. LAUR: And as I understand it, what the human factors are doing is verifying or validating that basically a go/no go criteria that you can meet the time whereas in the PRA risk assessment they use realistic timing and realistic scenarios and calculated the frequency of core damage sequences. So really it's not a comparable set of information.

CHAIRMAN DENNING: Yes. It does, however, give us a feeling as to what significance of margin in the design bases. But I think you're absolutely right, that that's probably the context that we ought to be interpreting this in rather than risk.

And I'm ready to move on to the next

viewgraph.

MS. MARTIN: These are the times that the licensee provided, the data that will be changed due to the EPU setpoints. This is a representation of the data that will change.

In the control room there will be no new displays except for as the licensee mentioned earlier, the SI accumulator should be upgraded to a digital display.

And all of the setpoints and displays will be normalized so that 100 percent remains a 100 percent and the actions don't change due to the renormalization.

For the SPDS, these are just the representation of the changes that will come. Nothing major. And this describes the change process that will be implementing the changes that we'll have.

For the simulator, as they mentioned previously, both the simulators have been benchmarked with engineering models. And they will be using the systematic approach training to train the operators for the --

CHAIRMAN DENNING: Thank you.

MS. MARTIN: This is just more general

information on the simulator changes and how they will cover the training for the simulator changes.

Our conclusion is that the licensee addressed the effects of the EPU on human factors and they have taken the appropriate actions to assure that the EPU does not adversely affect the operator actions. And we find these proposed changes to be acceptable because of their commitment to validation on Unit 2 and because of the issues that they've addressed.

CHAIRMAN DENNING: Very good. And I think we see no other questions.

Thank you very much.

And we'll move on to what is the last technical presentation, I think.

MR. PETTIS: Good morning. My name is Bob Pettis. I'm with the Division of Engineering. I'm filling in for Greg Galletti who was the technical reviewer for the Beaver Valley EPU. At present he's currently at Vermont Yankee and the license renewal inspection. So I'll do the best I can with what was the basis of his review.

As you're aware, the power ascension and testing program is covered under the SRP 14.2.1 and which we've had many discussions over the last several months.

The EPU test program should include sufficient testing to demonstrate that the SSCs will perform satisfactorily at the request power level. The Staff guidance considers the original power ascension test program that was done under the Reg. Guide 1.68 process and the EPU related plant modification, which most of the modifications fall into the area of plant systems branch which they probably have already provided their evaluation to you folks earlier today.

Staff guidance acknowledges that licensees may proposal alternative approaches to testing without adequate justification. We've centered around the large transient testing issue, but it's basically any departure from the original test program is reviewed as part of the technical justification for allowing those exceptions.

The Staff basis for requiring performance of testing including the large transient testing fell into the Reg. Guide 1.68 document which was basically established to ensure that there was a suitable test program at the original plant licensing phase that covered both the steady state and anticipated transients.

The objectives of Reg. Guide 1.68 were to familiarize operators with training, confirmation of design and installation of equipment, benchmark of analyses and codes and also to confirm the adequacy of EOPs.

One of the main objectives with 1.68 was also to provide necessary assurance that the facility could ge operated in accordance with the design requirements and validate any analytical models.

Under the Reg. Guide 168 there were a series of tests that were recommended back in the appendix. And two of those tests that were in the original 1.68 guidance were the so called large transient tests which are under discussion for the new plants today. And both of those tests that were required at original plant construction, again to validate analytical models in performance of a brand new plant.

Beaver Valley is planning on performing additional startup tests which were originally not part of the initial startup test program to maintain consistency with that of Unit 2. And I believe from what I could look at the SE, it had to do with the fact of the vintages of Unit 1 versus Unit 2 in order to have both plants be somewhat the same, the additional tests were included to make that happen.

Some of those examples included the secondary system vibration frequency and amplitude test, system expansion and restraint test, turbine plant system tests.

Beaver Valley will perform a series of post mod tests for plant design changes associated with the power uprate. A few of those are listed here. Replacement of main instrumentation, modification of HB turbine.

With respect to the transient testing issue, Beaver Valley like most others that have come before the agency, have elected not to perform the two large transient tests which are the MSIV closure and the generator load reject. Some of the accepted justification for not performing these tests for some of the previous plants were that the licensee's test program will monitor the important parameters during the power ascension test phase. And most of that occurs within 2½ to 5 percent increments where the licensee monitors the power ascension.

Tech surveillance and post mods will confirm the performance and capability of the modified components through tech spec testing, through normal QA and Appendix B type testing.

Operating history is a big factor that quite a few applications take credit for, which is listed in the SRP. And they've cited North Anna, Summer and Harris as similar plants that have undergone the uprates.

CHAIRMAN DENNING: Normally we tend to challenge the Staff in this particular area. But in all honesty, I don't think that there's any real serious concerns about large transient testing in this particular uprate.

MR. PETTIS: Okay.

MEMBER SIEBER: Percentage of power increase is really pretty small.

MR. PETTIS: I believe this 108 percent on Beaver Valley.

MEMBER SIEBER: Yes.

MR. PETTIS: But just to maybe reenforce that--

CHAIRMAN DENNING: And also looking at the lack of major modifications in --

MR. PETTIS: Yes. I was just going to mention that the technical staff in the balance-of-plant section identified that the balance-of-plant modifications don't warrant the need for the transient testing.

So based upon that part of the Staff's review, the Staff concludes that the EPU is satisfactory.

CHAIRMAN DENNING: Are there any questions? Thank you very much.

MR. PETTIS: Okay. Thank you.

CHAIRMAN DENNING: Well you never thought you were going to get away that easy, did you?

MR. PETTIS: No.

CHAIRMAN DENNING: Okay. Well, I don't hear anybody saying we ought to go to lunch. Let's finish out.

MEMBER SIEBER: If you want me to.

CHAIRMAN DENNING: Yes. Okay. So, first we'll hear from FENOC management and their wrapup.

MR. LASH: Again, I'm Jim Lash, Site Vice President. And I will be brief. I know I'm us and lunch.

The past two days I think our team as well as the NRC the presentations have concluded that the reviews have been detailed and there have been no safety issues identified and the Beaver

Valley approach is a conservative approach both from an analysis as well as a power escalation that we plan to employ at the station. And I assure you that the implementation of the power uprate will be performed safety and reliability using our plant modification process, our operator training program, our plant procedure modification processes and our adherence to the operating conditions.

That completes our presentation unless there are questions from myself.

CHAIRMAN DENNING: I don't see any questions. I would like to thank you and your staff for a very good presentation.

And as far as the full Committee meeting, we'll give you some more guidance as to what our expectations there. We have two hours there.

There was a little bit of duplication between some of the regulatory Staff's presentations and some of your presentation. I think that our guidance will be largely that we're going to focus more on your presentations in a few areas, and some of them are obvious.

MR. LASH: Sure.

CHAIRMAN DENNING: We're going to want

to certainly focus on the results of the accident analyses. But some other areas that aren't necessarily problems, but which ones has to look at like potential for vibrations and stuff like that. I think your story today was quite good on that. We'll have to abbreviate those.

And we'll give you some more guidance as to what the presentations.

MR. LASH: I appreciate that. I was going to ask you for that guidance. And I appreciate that.

CHAIRMAN DENNING: Yes. I think that rather than attempting to really lay it out at this meeting, Ralph will send you a message that kind of indicates how much time to figure on.

MR. LASH: Okay. Good.

CHAIRMAN DENNING: And in which areas.

MR. LASH: Very good.

CHAIRMAN DENNING: But there's nothing missing that I see, you know, that we're going to have to have additional things. It's really a matter of compressing and perhaps eliminating in some areas. And from the Staff's side, I think it's going to be an elimination in a lot of areas of some of the reviews that were of value to us to make sure that we saw that they had been comprehensive in their reviews and to see what their considerations were, but as far as the full Committee is concerned I think would be unnecessarily duplicative.

MR. LASH: Okay. Thank you.

CHAIRMAN DENNING: Okay?

MR. LASH: I do have another question, though.

CHAIRMAN DENNING: Yes.

MR. LASH: And that is just to confirm I think we've been checking all along. I don't believe we owe the Subcommittee anything?

CHAIRMAN DENNING: Let me just see if Ralph agrees.

MR. CARUSO: That's correct.

CHAIRMAN DENNING: Although it looked at some points like there might be, everything has been provided that we had asked for.

MR. LASH: Okay.

MEMBER SIEBER: Well, if Ralph has some of this typical --

MR. CARUSO: I'll be getting a copy of the WRP-2M. I'll send you off that today or tomorrow.

MR. LASH: Okay. Good.

CHAIRMAN DENNING: Okay?

DR. BANERJEE: And ATWS, I guess, but you have that.

MR. CARUSO: And I'll give you a copy of BACCHUS, too.

CHAIRMAN DENNING: Yes. Yes.

MR. LASH: Very good. I would like to thank the Subcommittee for allowing us to make this presentation of our power uprate proposal.

I'd also in your presence like to thank my team, which includes the subcontractors from Westinghouse and Stone & Webster for supporting us. The folks worked very hard. Their preparations were very thorough and I think that bore itself out in their presentations. So I thank the team as well.

That's it.

CHAIRMAN DENNING: Thank you.

MR. LASH: Thank you.

CHAIRMAN DENNING: And wrapping up for the Staff?

MR. COLBURN: I don't have any slides, so I can do that from here.

My name is Tim Colburn again.

And I'd just like to thank the Subcommittee also for allowing the Staff to make its presentation.

We reviewed the licensee's submittal against all of the areas in the Review Standard RS-001. We had a challenging review. There were numerous requests for additional information we provided to the licensee, but they stepped up and provided information every time we asked them questions that resolved all of our issues.

The Staff believes that the licensee has done a very good job in resolving the open items that we have along the review path and also in ultimately demonstrating that they can adequately and safely implement the power uprate of 8 percent for Beaver Valley Units 1 and 2.

And, again, look forward to whatever guidance the Committee would like to provide us on preparing for the full Committee.

CHAIRMAN DENNING: Very good. Thank you.

Any questions or comments from the Subcommittee?

Anything else we want to discuss before we --

MEMBER WALLIS: Well I think we should establish that we don't have any sort of outstanding questions or anything.

CHAIRMAN DENNING: Absolutely. Jack, do you want to start off?

MEMBER SIEBER: I would indicate that I worked at Beaver Valley for many years. So I don't have a bias one way or another.

When I read the application and through the SER, I found the application pretty easy to read, it was straightforward, easy to follow, legible, made sense. On the other hand, that was your second shot at it, I think.

In the SER it indicates a lot of requests for additional information that tell me that maybe the first application wasn't real complete.

On the other hand, all of that has been remedied and I think the document is in good shape. And I think the modifications that you intend to make on the plant are reasonable. The EPU level that you chose is reasonable because you still remain sort of in the middle of the pack as far experience is concerned. There are a number of plants like yours that operate basically with the same parameters. So you're not blazing ground in that area.

I was impressed with the presentations. I think that they demonstrated a good knowledge of analytical methods that were used and what they meant. And I congratulate your staff for that.

We had a discussion with some of your folks at the Ginna EPU and I noted that you've been sending people out to see what goes on in these meetings as a way to prepare for this meeting. And, obviously, you learned a lot because this meeting in my opinion went very well. The questions that we asked and that were important were answered well and with the analytical backup and operating experience backup. And I think those factors are important.

As far as issues are concerned, I don't see any issues that arise from this application. And I agree with the Staff's conclusions. And when we get an opportunity to vote on Rich's letter which he'll write, hopefully --

CHAIRMAN DENNING: I'd better. They don't pay me otherwise.

MEMBER SIEBER: -- I personally feel in the affirmative at this time with regard to granting the uprate.

So that would be my conclusion.

CHAIRMAN DENNING: Thank you.

Sanjoy, do you want to comment?

DR. BANERJEE: I think that the approach taken is quite conservative and lies within the bound of what has been done before. So I have no particular concerns.

I think I'd like to follow up a little bit more on the fate of the boron, which I will do when I look at the BACCHUS report. And a little bit more on the refluxing mod. But other than that, I have no major points. But the applicant doesn't really have to supply any more information at this time.

CHAIRMAN DENNING: Let me interject that with regards to the boron, I think there is more work that has to be done here. But not within the context of this EPU. And I have some recommendations that I will to the Staff about how I think that ought to be done there.

DR. BANERJEE: Far more generic issues which --

CHAIRMAN DENNING: Yes.

DR. BANERJEE: -- should not necessarily be a burden on the applicant.

CHAIRMAN DENNING: Yes.

MEMBER SIEBER: Yes, I agree with that.

CHAIRMAN DENNING: Graham?

MEMBER WALLIS: Well, I'm glad Jack made the speech, now I don't have to make it. I'm pretty satisfied with what I've heard.

I think in front of the full Committee you just have to present the key things and what are the main effects of the EPU as they effect the criteria for reactor safety; how do you meet those criteria. That's really the main issue.

Try to avoid a long discussion on PRA because, you know, the changes are so very small they don't effect the ultimate decision.

CHAIRMAN DENNING: Okay.

MEMBER WALLIS: I think there are some of these questions like the boron thing that we keep coming up with need to be resolved better at some time. But that's not something we should hang on this particular licensee.

Thank you.

CHAIRMAN DENNING: Tom?

MEMBER KRESS: I think it's all been said.

CHAIRMAN DENNING: Otto?

MEMBER MAYNARD: I think it's all been said, too.

CHAIRMAN DENNING: I think it's all been said, too.

We're adjourned.

(Whereupon, at 12:01 p.m. the meeting was adjourned.)

Official Transcript of Proceedings

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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

MEETING OF THE SUBCOMMITTEE ON POWER UPRATES

BEAVER VALLEY POWER STATION EXTENDED POWER UPRATE

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WEDNESDAY,

APRIL 26, 2006

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The subcommittee meeting convened at the Nuclear Regulatory Commission, Two White Flint North, Room T-2B3, 11545 Rockville Pike, at 8:30 a.m., Richard B. Denning, Chair, presiding,

SUBCOMMITTEE MEMBERS PRESENT:

RICHARD B. DENNING

, Chair

SANJOY BANERJEE

ACRS, Consultant

THOMAS S. KRESS

OTTO L. MAYNARD

JOHN D. SIEBER

GRAHAM B. WALLIS

ACRS STAFF PRESENT:

RALPH CARUSO

FIRSTENERGY STAFF:

BOB BAIN

Stone & Webster

DON DURKOSH

FENOC

BILL ETZEL

FENOC

KEN FREDERICK

FENOC

DAVID GRABSKI

FENOC

JEFF HALL

Westinghouse

NORM HANLEY

Stone & Webster

GREG KAMMERDINER

FENOC

COLIN KELLER

FENOC

JAMES LASH

FENOC

MARK MANOLERAS

FENOC

PETE SENA

FENOC

GEORGE STORLIS

FENOC

MIKE TESTA

FENOC

NRR STAFF PRESENT:

TIMOTHY COLBURN

STEVEN LAUR

GREGORY MAKAR

ROBERT PETTIS

MARK RUBIN

THOMAS SCARBROUGH

ANGELO STUBBS

A-G-E-N-D-A

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

8:33 a.m.

CHAIRMAN DENNING: We are now back in session. And this is Wednesday, April the 26th. And we're going to start off discussing mechanical impacts and Mike Testa.

MR. TESTA: First I'd like to thank the Committee for the opportunity to speak here today. My name is Mike Testa, I'm the extended power uprate Project Manager for Beaver Valley.

A little background on myself. I have 23 years of experience at Beaver Valley Power Station. The last five year I've been the uprate Project Manager and I also was on the full potential project from the beginning.

Today I'll be discussing the mechanical impacts that the uprate has on Beaver Valley Power Station.

Next slide, John.

I'll be discussing the steam generators, balance of plant heat exchangers, vibration monitoring program for the secondary piping systems, cooling water systems and flow accelerated corrosion, of which we'll have our program owner come up and speak on that program.

Today if there's any questions, I have Jeff Hall from Westinghouse to assist me as well as Bob Bain from Stone & Webster.

For steam generator vibration, we looked at the first thing, we used a thermal-hydraulic code Athos that computes the thermal-hydraulic parameters the tubes so the tube bundle would be subjected to.

We looked at the vibration potential in the U-bend and tube bundle entrance region. Out of two vibration mechanisms that were considered, were fluid-elastic instability, vortex shedding and random turbulent excitation.

And we also looked at tube wear. And that's tube wear in the U-bed radio at the antivibration bar interface.

The tube bundles, just the difference between the units now. For Unit 1 we replaced the steam generators. We discussed that yesterday. Model 54. Just installed in fact a few weeks ago here. The model 54 was designed for uprate conditions so the stress report, the design report considered uprate.

For Unit 2 we have the Series 51 steam generator, of course, which now will see increased flow because the uprate.

We reviewed the --

MEMBER WALLIS: I presume the steam generators is plural and you installed three of them?

MR. TESTA: Yes.

MEMBER WALLIS: Not just one?

MR. TESTA: Yes, correct. That's correct. Yes. Three loop PWR 3 steam generators.

We looked at the flow induced vibration effects --

DR. BANERJEE: What's the difference between the two?

MR. TESTA: Between a model 54 and 51?

Jeff?

MR. HALL: Yes. This is Jeff Hall from Westinghouse.

The differences are really many. With respect to the tube material itself the 51M is a 600 mm tubing where the 54F is a 690 thermally treated tubing. So issues such as stress cracking are greatly reduced with the new model generator.

The support plates are stainless for the new model generator versus carbon steel support plates.

The antivibration bars are better

designed for the new unit.

DR. BANERJEE: What does that better design mean?

MR. HALL: The support conditions are more assured. Where for the 51M sometimes you could pick up gaps between AVBs and the tubes, with the newer design with the reduced gaps you have a reduced potential for wear at the AVB sites.

DR. BANERJEE: So are these just gaps or are there actually things holding the tubes in place?

MR. HALL: Well, you could think of it as a bar that's inserted between the tubes in the U-bend region. It's a flat bar. Essentially it provides a support location to prevent the tube from moving in the out of plane direction.

DR. BANERJEE: But they're not broach plates or anything like that?

MR. HALL: Well with respect to the support plates. The support plates are in fact broached.

DR. BANERJEE: Okay.

MR. HALL: Where the 51M is a circular drilled hole.

DR. BANERJEE: And the 54F?

MR. HALL: The 54F is a broached configuration.

MR. KAMMERDINER: Excuse me, Jeff. This is Greg Kammerdiner.

Back on the AVBs, the other difference with the 54Fs, there's an extra set of AVBs. 51s have two sets of AVBs, the 54s have three. So there's more support in the upper bundle because there is an extra set of AVBs in the 54.

DR. BANERJEE: And the number of tubes are the same?

MR. KAMMERDINER: There's approximately 400 tubes more in the 54?

MR. HALL: Yes.

DR. BANERJEE: Four hundred out of how many?

MR. KAMMERDINER: The 51Ms have 3,376. The 54s approximately 400 more.

DR. BANERJEE: Ten percent more?

MR. KAMMERDINER: Yes.

DR. BANERJEE: Thanks.

MR. KAMMERDINER: Fifty-four stands for 54,000 square feet of heat transfer area. The 51, is 51,000 square feet.

DR. BANERJEE: Thank you.

MEMBER WALLIS: So the AVBs limit the amplitude of the oscillation, but they also give the tubes something to rub against, to bang against?

MR. HALL: Yes.

MEMBER WALLIS: Well, they're good and bad at the same time in a way.

MR. HALL: Beg your pardon?

MEMBER WALLIS: They're both and bad?

MR. HALL: Well, yes. No, they're actually all good.

MEMBER WALLIS: Okay. But it says here tube wear at IBBs. There is some rubbing or something going on?

MR. HALL: Yes. And that's primarily a result of the fit up between the tube and the bar itself. If you have the ability to move back and forth, well the tube is going to move back and forth. But if you're holding it sufficiently so that you don't have relative motion, well then you don't get wear.

MEMBER SIEBER: The AVBs go in the U-bend area, not below?

MR. HALL: That's correct.

MEMBER SIEBER: The old ones sometimes they weren't long enough to catch all the tubes. So you would end up with a tube that's not supported.

MR. HALL: Yes. And actually in both cases, the 51 in particular, there are some tubes in the U-bend region that are unsupported.

MR. TESTA: And actually, that's a lead in for the next bullet where we looked at -- go back, John.

Yes for Unit 2 again for the series 51, unsupported U-bends were reviewed for increased fatigue. And because the analysis that was performed, there was six tubes that we had to take out of service. And we did that.

Okay. As far as the next slide here, I just wanted to touch on the steam dryer. Again, look at the comparison between the PWR and the BWR. Just a little description on the secondary steam dryers on the steam generators. Now the main difference is between the 51 and the 54 is that the 51s have a two tier arrangement for the secondary dryers. I have sketch behind this to show that, whereas the model 54 has a single tear arrangement.

It's better illustrated here. Again, with the 51 they have two tiers of secondary steam dryers. You can see the lines that are drawn. The steam comes up and enters into the side region of the secondary dryer and then flows up, comes up through and then has a natural progression up through the secondary dryers.

The flow velocity in that region is on the order of 3½ to 4 feet per second. And you can see the vicinity of the nozzle region there's no structural components within the vicinity of the nozzle.

CHAIRMAN DENNING: I realize that later you're going to talk a little bit about experience. But could you tell us at this point how much experience is there with the 51 at the conditions that you're now going to go to?

MR. HALL: With respect to these conditions there's an immense amount of experience. These steam dryers, this configuration is used in a multitude of steam generator models, not just the 51s. The D models, D2, D3, D4, D5 all have a very similar arrangement. 54F a very similar arrangements. The Fs all have a two tier arrangement.

The velocities coming out of that area are all pretty much of the same order of magnitude. I mean, a couple of feet per second one way or the other, but they're all essentially the same.

Totally different orders of magnitude than some of the boiling water reactor dryers.

MEMBER SIEBER: Well, the one thing you don't have is a 180 degree change of direction.

MR. HALL: And all the consequences of that with respect to the turbulence that you can get, yes. It's all pretty much it comes out of the steam dryers and it continues on right up to the steam nozzle.

MEMBER SIEBER: The velocities are pretty low. They're like --

DR. BANERJEE: Can you stay there. Can you go back to that slide?

MR. TESTA: That one?

DR. BANERJEE: No, no, no.

MEMBER WALLIS: The velocities?

DR. BANERJEE: Yes.

MEMBER WALLIS: The one with the velocities, 107.

DR. BANERJEE: The velocities.

MEMBER WALLIS: That's it.

DR. BANERJEE: That's it.

MEMBER WALLIS: There's no history of problems with these dryers, I understand?

MR. TESTA: That's correct. In fact here

from this slide here it was to compare, again the 51 to the BWR. You can see that they have low velocities up through the dryers at 3½ to 4 feet per second where the BWR was on the order of 100 feet per second. And there have been no operational issues reported in the 51s or the 54s.

We had a backup slide just to show the operating experience.

DR. BANERJEE: Can you, please?

MR. TESTA: Sure. Okay. So for example, you know, well Beaver Valley which is going to operate at 2910. The difference with the model 54 one tier secondary dryer in the Unit 2, with two tier you can see the comparison to the other plants that utilize the similar secondary steam dryer arrangement.

MR. HALL: Yes, but these are not the only plants to have this particular dryer arrangement, too. There's many more.

MEMBER SIEBER: As far as megawatt production, Beaver Valley and North Anna are about the same so the operating experience from North Anna at that power level, it's got a fair amount of time behind it.

MR. TESTA: That's correct.

MEMBER SIEBER: So they aren't really breaking any new ground here.

MR. TESTA: In fact, North Anna is on the list here where they're operating at 2905.

MEMBER SIEBER: Got them beat by five?

MR. TESTA: Yes. Okay. Okay, John. No, go forward.

Now if there's no other questions on the steam generator, we also looked at balance of plant heat exchangers. From the uprate looking at the heat balance and the flow parameters that the equipment would be subjected to. We looked at the feedwater heaters and the feedwater heaters will operate within the design capacity.

The moisture separator reheaters, we went back to the vendor. We had a specific analysis performed to show acceptability under the increased flows.

As we mentioned yesterday, one of the modifications that we're going to do is on the condenser. Now our Unit 1 condenser was retubed a while back. And at that time the condenser was staked. Prior to the power escalation we will be taking the condenser in order to limit the tube vibration.

Vibration monitoring. This is a monitoring program for the secondary side for the balance of plant piping. We're going to monitor the secondary systems pre and post-EPU. This is going to include baseline walkdowns on each of the plants which we've already done. We have documented walkdowns.

Areas of interest where there's level of vibration that causes us to pay particular attention as we escalate power, we've identified those locations.

All this is within the guidance of ASME OM Part 3 that prescribes the walkdowns or the acceptance criteria that could be used and the method of performing this program.

CHAIRMAN DENNING: Could you help me a little bit on a walkdown where you're looking for vibration, what does one do quantitatively there?

MR. TESTA: Okay. What we do there is, for example, we came up with a screening criteria. We're looking at the displacement I'd say on the order of an eighth of an inch. And we'll walk it down to see if there's any signs, any noticeable signs of vibration. And we basically have documented from the plant, basically going from say component to component, basically identifying if we have vibration levels that would exceed that limit.

CHAIRMAN DENNING: Visually?

MR. TESTA: Visually. That's correct.

I have Bob Bain from Stone & Webster. If you'd like to add?

MR. BAIN: Yes. This is Bob Bain from Stone & Webster.

We followed the basic guidance of OM3 as Mike says. The first test criterion we used was visual on displacement of an eighth of an inch, which is within the guidance provided in OM3. They allow for visual measurements using simple devices such as rulers, hand held type mechanical simple devices like pencils, literally. And an eighth of an inch peak to peak displacement is easily visual on a focused walkdown. And as Mike says, these walkdowns were basically focused.

Over the last three or four years, actually, we took a schematics and basically connected the dots from equipment. So from pump to valve, valve to vent or drain, vent or drain to branch lines. So it was a focused walkdown looking at the piping, the components as well as the support hardware.

And any observation, again eighth of an inch was a fairly stringent criteria. Easily visually noted. That would get it onto this list of interest, as Mike identified.

And we followed up that list of interest literally over the last three or four years for both units.

CHAIRMAN DENNING: Is there quantitative stuff that one can do? I mean, are there instruments that you can go and put it up against the machine? I mean, the equipment --

MR. TESTA: Yes, there are.

CHAIRMAN DENNING: -- and have a measure of not only the displacement but the frequency?

MR. TESTA: Yes. There's a portable device, hand held accelerometers. And, again, we conduct these walkdowns. We use the experienced engineers. And if there's any question about the acceptance of the level of vibration, then we will use accelerometers to record the displacement and the frequency.

MR. BAIN: Yes. This is Bob Bain again.

And this hand held equipment that Mike references actually gives you data in displacement or velocity or acceleration. And OM3 allows you to do more detailed evaluations if required using velocity or displacement data. So the hand held is a good device to give you the next level of detail quantitatively.

MR. TESTA: Okay. Just the last mention here, large equipment like the reactor coolant pump and the turbine have continuous monitoring available. So we'll be monitoring that as we escalate power.

Okay, John.

Now the next area we looked at is cooling systems. The bottom line here is that the systems remain capable of dissipating heat for normal shutdown and accident conditions.

WE looked at these following systems, the flows were adequate without modification:

The river water system. Beaver Valley 1 the equivalent system service water for Unit 2;

The component cooling water;

Residual heat removal, and;

The safety injection containment depressurization system which uses the recirc spray heat exchangers.

Next slide.

Spent fuel cooling. We looked at spent

fuel cooling. As part of the project or the overall initiative, which we started we said five to six years ago, we looked at spent fuel cooling. And there was an amendment that we put in where we looked at the offload time. At that time we performed the analysis to incorporate the uprate decay heat loads.

MEMBER KRESS: Do you have dry casks on the site?

MR. TESTA: Not at this point, no. Still use the fuel pool.

MEMBER WALLIS: I think I remember your burnup is the same as it was before essentially, is that right?

MR. TESTA: Yes, I believe so. Yes.

The last area to touch on here is the auxiliary feedwater system. The auxiliary feedwater is fed from the condensate storage tank. The condensate storage tank is sized for 9 hours of hot standby conditions. And with the uprate or the increased decay heat, we've revised the tech specs to require 130,000 gallons useable volume for each of the tanks for both Unit 1 and Unit 2.

The other thing with the aux feedwater system, there were two accidents: The feedline break and loss of normal feed that required us crediting two aux feed pumps.

CHAIRMAN DENNING: I didn't understand with regards to the tech spec limit and the 130,000 gallons. What do you do physically to assure that?

MR. TESTA: Basically we have the calculated tank volume and maintain a level on the tank.

CHAIRMAN DENNING: So it's a level on the tank that has to be assured now that it's slightly higher than it was previously?

MR. TESTA: Yes. Yes.

CHAIRMAN DENNING: Gotcha.

MR. DURKOSH: This is Don Durkosh from Beaver Valley Operations.

Basically we obtained curves that show based on indications available to us what the volume is. And on every shift we have minimum levels that we're required to verify on a shiftly basis. So that's how we maintain our minimum tech spec values.

MEMBER MAYNARD: You didn't make any modifications to the tank. You're just changing the level setpoint there.

MR. TESTA: That's correct. That's correct.

MR. CARUSO: Why would you not normally keep the tank full?

MEMBER SIEBER: It goes up and down. You have to have surge volume.

MR. TESTA: To answer that question we normally do. As part of the review of our L5 logs we typically, our levels are high. What we try to do is basically clear the alarms. We have a low alarm that indicates we're approaching a tech spec limit. And normally we have a high alarm very close to the overflow. So we try to maintain it within that range so we have no alarms in the control room.

MR. TESTA: Okay. Again, just to finish this out here, there are two accidents that required us to credit two pumps. This was already in place for Unit 2. And with the revised analysis Unit 1 will now require two pumps also for these two accidents. It's basically accounting for the increased decay heat plus the addition of the cavitating venturies, which puts a little more system resistance into the system.

CHAIRMAN DENNING: And that's two out of how many?

MR. TESTA: Two out of three.

CHAIRMAN DENNING: And it had been one

out of three?

MR. TESTA: It had been one out of three, just for Unit 1. Unit 2 was already crediting two pumps.

Okay. Well, this completes my part of the discussion. I have Dave Grabski here, which he's our flow accelerated corrosion program owner, and he'll talk about the program.

Thank you.

MR. GRABSKI: As Mike said, I'm Dave Grabski. I am the FAC program owner.

A little background. I'm a FirstEnergy employee. I worked at Beaver Valley and before that Shippingport Atomic Power Station for a combined 26 years.

I've been the FAC program owner since the early '90s.

Next slide.

The first bullet, the EPU effects evaluated using CHECWORKS. So we've taken the revised heat balance diagram parameters and using the CHECWORKS models determined analytically what we'd expect as far as our wear rates. With most uprates, we've seen an increase in velocity and temperature. And those two factors play differently with different systems. Some systems we've seen a decrease in our wear rates, and others we've seen a slight increase.

The feedwater and extraction steam systems, those systems had a decrease. Systems like the feedwater heater drains, condensate have increased. Again, because of the play of those different parameters: Velocity and temperature mainly.

In preparation for the uprate we've actually replaced two extraction steam Ts because of the increase in our SMR relief valve set point that has cut into our margin between our measured wall thickness and our required wall thickness. Extraction steam is one system at Beaver Valley that does wear due to the flow accelerated corrosion mechanism.

CHAIRMAN DENNING: So there wasn't a materials change, it was just a thickness change?

MR. GRABSKI: We have upgraded the material to a chrome-molly. Basically anytime we make piping replacements at Beaver Valley, we'll upgrade to a chrome-molly. Chrome-molly is much more resistent to this particular degradation mechanism.

Based on the engineering evaluation we're going to focus on a few more systems. Well, not more systems, but more components within those systems, on those systems that we expect an increase in velocity. Mainly our moisture -- or I should say the heat drain system from our 4th to 5th point heaters, we had a significant velocity there. So we're going to focus examinations in the next outage there to get a baseline where we're at. And in the future go back to these areas to see how they're doing.

And there's some components at Beaver Valley 1 and 2 in the 4th point heat drain line. It's showing you in the next to the last column there some of the wear rates we saw before the outage. Very low. And heater drains is a low wear system at Beaver Valley. But we do see some increases based on the uprate.

DR. BANERJEE: Do you have a diagram showing where these components are in the steam cycle?

MR. GRABSKI: I don't have --

DR. BANERJEE: I have no idea where the four point heat is or what -- I imagine that it's extraction --

MEMBER WALLIS: This is a preheater.

DR. BANERJEE: Preheater?

MR. GRABSKI: Yes. We have six --

MEMBER WALLIS: Well, these aren't safety concerns anyway. These are just embarrassments for you if you break a pipe, it might be dangerous for anyone who is around the pipe.

MR. GRABSKI: It could be a personnel issue.

MEMBER WALLIS: It's dangerous for your people, but it's not a nuclear --

MR. GRABSKI: That's correct. This is a non-safety related piping systems.

MR. STORLIS: My name is George Storlis. I'm a FENOC employee.

An in Operations I can get a little bit of perspective to what the feed heater string is. The feed heater string is compromised of six feed heaters in line with the condensate feed system to preheat the feed. The fourth point is fourth in line, the sixth point being the lowest energy or lowest pressure system and the first point being an extraction steam of highest pressure off of the turbine cycle. And the fourth point is in route to that.

And we're talking pressures, temperatures that compliment the feedwater heat up that approaches the 440 degrees or so when it ultimately is arriving at the steam generators. So it takes a portion of the energy from the turbine cycle and uses that to preheat the steam and the shelf tube arrangement.

And that's the basics of it. If there's any questions, please ask.

DR. BANERJEE: Is the steam wet at this point?

MR. STORLIS: Yes. Yes.

DR. BANERJEE: What's the quality?

MR. STORLIS: Without having the curves and the diagram in front of me, I can't speak to that, that specific quality.

MR. KAMMERDINER: Probably some in the 90s.

MEMBER WALLIS: Pretty high.

MR. TESTA: This is Mike Testa.

We have a heat balance diagram, maybe that would help.

DR. BANERJEE: Does it show quality at various points, extraction points?

MEMBER SIEBER: That chart would work.

DR. BANERJEE: I can't do it in my head.

MEMBER WALLIS: And the problem is the wetness, presumably.

DR. BANERJEE: Yes, the wetness.

MEMBER WALLIS: But it's a few percent. It's not a humongous amount or is it designed to extract in a way that it separates the wall, and it would be wetter, wouldn't it?

MR. GRABSKI: Actually the steam quality is fairly low.

MEMBER WALLIS: That's in the turbine. But when you extract, don't you sort of have something that's centrifugally separates or anything like that?

MR. GRABSKI: We have steam traps and orifices to pull off the moisture.

MEMBER WALLIS: It's an oxidate or whatever it is that comes out, ends up in some condensate -- where does it go?

MR. GRABSKI: It varies with the system that might be wearing. If you're feedwater's wearing, you're going to get it in the steam generators on secondary side. A lot of the heater drains go to a receiver tank.

MEMBER WALLIS: The crude appears in the

steam generator. Where does the stuff that's worn away from the pipe?

MR. GRABSKI: Again, depending on what system it's in. The heat drains, there's a heat drain receiver tank that it could filter out at. We do have -- do you have something?

MR. HANLEY: Yes. Norm Hanley from Stone & Webster.

All the secondary side condensate and extraction steam heater drains all recovered. Some of it cascades back to the condenser, some of it's pumped forward to the feed pump suction. So it is all recovered.

MEMBER WALLIS: Isn't a lot of it dissolved and then it appears somewhere else in an--

MEMBER SIEBER: Heater drain and steam generator.

MEMBER WALLIS: In these steam generator?

MEMBER SIEBER: Yes. There is a blow down line on the steam generator.

MR. HANLEY: Right. There's a blow down in the steam generator. They also sample the secondary side.

MEMBER MAYNARD: Well, do you have

condensate polishers? Do you run it through --

MEMBER SIEBER: Only on Unit 2.

MEMBER MAYNARD: Only on Unit 2.

CHAIRMAN DENNING: Can you comment on the accuracy of CHECWORKS? I mean, obviously, it's not the four significant figures that's in that table.

MR. GRABSKI: Basically the models will improve with the number of examinations you do on the system. It correlates with the data you have. So without any data, I would take it as just a ranking. And that's what we use it for, as a ranking. But actually in our extraction steam which we examine the heck out of, they actually correlate pretty well once you get enough data in there.

MEMBER MAYNARD: I take it you also use industry experience what's found at other places --

MR. GRABSKI: Oh, absolutely. Our examinations are the backbone. But certainly ops experience, trending of data at our plants and then that's all factored in.

DR. BANERJEE: Is there any increased erosion due to the wet steam, the velocities being somewhat higher or --

MR. GRABSKI: Yes. That's in the

CHECWORKS algorithm higher velocity results in a higher wear rate.

DR. BANERJEE: Due to erosion or is it some erosion/corrosion?

MEMBER WALLIS: I suspect it includes both erosion --

MR. GRABSKI: The FAC takes in the both. That's the mechanism.

DR. BANERJEE: But does it also depend-- does this depend on the wetness as well?

MR. GRABSKI: Absolutely. That's a factor in the algorithm.

DR. BANERJEE: You feed this stuff into CHECWORKS and out comes these numbers?

MR. GRABSKI: Yes.

DR. BANERJEE: Hopefully.

MR. GRABSKI: Hopefully, yes.

DR. BANERJEE: Yes. Who developed this thing?

MR. GRABSKI: EPRI developed CHECWORKS. And it's the industry --

DR. BANERJEE: Probably validated against data?

MR. GRABSKI: They call it an empirical study --

DR. BANERJEE: I see.

MR. GRABSKI: -- based on lab and actual events in the industry.

MEMBER KRESS: There's sort of a Bayesian update. You go in and inspect and you compare the inspection findings, and then you adjust CHECWORKS to better agree with your findings?

MEMBER WALLIS: Learns about your --

MEMBER SIEBER: Putting your own data --

MR. GRABSKI: Exactly. As I said, they call it a pass one without any data. Once you get enough data in there, it correlates itself. And you have a line correlation factor, it's called.

DR. BANERJEE: So the predicative capability is always in question of these types of things? It's only as good as your database?

MEMBER SIEBER: By the time you are ready to decommission the plant, it will be very --

DR. BANERJEE: Yes, it'll be excellent by them.

MEMBER KRESS: Or by the time you're ready for a license extension.

DR. BANERJEE: Extrapolation is always dangers in these sorts of things. There's no theory or model there, right?

MR. GRABSKI: Well though EPRI calls it a model and it certainly does take into consideration velocity, temperature --

MEMBER MAYNARD: And geometry, right?

MR. GRABSKI: And geometry. Exactly. But again, it's as good as the data you're putting into it at the point.

DR. BANERJEE: Let's imagine that we take this today with the data you've got and try to predict what will happen two years from now. Has it ever been tested in this mode to show whether it gives a reasonable prediction?

MR. GRABSKI: Yes, I think it has.

DR. BANERJEE: It does?

MR. GRABSKI: Yes, it does. It certainly. Yes. It'll give you --

MEMBER MAYNARD: Isn't the main purpose of it, though, to predict areas where you may have high wear rates and that you inspect those and that you put those in your trending program? And you're actually using more actual trend data than you are a prediction from the program as to when that line might break?

MR. GRABSKI: Exactly. It gives you the places to look first. The highest susceptible line.

And I think it does a very good job of that. But once you get into a qualitative or quantitative measure, that's when you need to get some data in there to verify what the model is telling you.

You may be right on the money, but again once you get more and more data in there, you correlate the model and then it becomes a very good predictive tool.

MEMBER MAYNARD: Yes. Most of the plants do a lot of measuring of a large number of areas where they measure and periodically do that so they can see what's trending.

MR. GRABSKI: Exactly.

MEMBER MAYNARD: It's not just using a computer program to --

MR. GRABSKI: No. Your data proves it, but it's a great start because it's going to tell you that this T is more susceptible than this T, elbow to elbow.

MEMBER MAYNARD: But again that's the way the nuclear safety issue other than if it could result in an unnecessary plant transient or it may be a personnel safety, but from a nuclear safety accident it's not.

MR. GRABSKI: That's true.

MEMBER SIEBER: And if you take a big fitting like an elbow or a T, a single measurement is inadequate. You have to basically put a grid on that fitting.

MR. GRABSKI: Right.

MEMBER SIEBER: Take a lot of measurements of different positions. Because the wear will be local to someplace where there is an eddy in the flow stream.

MR. GRABSKI: That's correct.

DR. BANERJEE: Have you seen any erosion in the high pressure stages?

MR. GRABSKI: Excuse me?

DR. BANERJEE: Did you see any erosion at all in the high pressure stages?

MEMBER SIEBER: Main feed?

DR. BANERJEE: Yes.

MR. GRABSKI: Some feedwater, we have very low wear rates there. In our main steam coming off the steam generators, we haven't seen any wear--

DR. BANERJEE: What about the turbine plates, any erosion there, high pressure plates?

MR. GRABSKI: I don't know. That's not my expertise on the turbine.

MEMBER SIEBER: But generally speaking--

DR. BANERJEE: You should have any.

MEMBER SIEBER: -- what erosion you see, you see at the very -- the exhaust end of the turbine. And if your moisture separators and everything are working properly, you don't see hardly anything at all.

DR. BANERJEE: Not in nuclear plants, but some fossil plants you do because of the oxide--

MEMBER SIEBER: Well, generally the fossil plants are better than the nukes because they operate at a higher temperature.

MR. GRABSKI: That's true.

DR. BANERJEE: Yes. But the oxide flakes come and hit the high pressure stages sometimes, depending on how you cycle the plant. But you don't see any so the higher velocity doesn't give you a problem?

MR. GRABSKI: Again, I'm not a turbine guy.

DR. BANERJEE: Right.

MEMBER WALLIS: It's not a nuclear problem. It's not a nuclear safety problem. Just expensive if you have to fix the turbine.

CHAIRMAN DENNING: I think we're completed them, yes?

MR. GRABSKI: Yes, unless you have any questions.

CHAIRMAN DENNING: I think we're good. Thank you.

MR. GRABSKI: Thanks.

CHAIRMAN DENNING: And I think NRR now is going to present in the same basic area.

MEMBER WALLIS: They're going to defend CHECWORKS, are they?

CHAIRMAN DENNING: You can go ahead.

MR. SCARBROUGH: Thank you.

Good morning. I'm Tom Scarbrough in the Division of Component Integrity of NRR. And with me today is the Branch Chief in Division Engineering, Kamal Manoly and Dr. John Wu.

We're going to talk about the engineering mechanics aspects of the review. In terms of the components evaluated, they included the reactor vessel, the internals, the nozzles, supports, control rod drive mechanisms, the steam generator, reactor coolant pumps, the pressurizer and the supports, nuclear steam supply system and balance of plant piping systems and supports and safety related pumps and valves. Motor operated valves, air operated valves and safety relief valves.

The scope of the review included the impact of the EPU conditions due to changes in system pressure, temperature and flow rate.

The review of the licensee's evaluations of EPU conditions including the analytical methodology, loads, flow-induced vibration, calculated stressed and cumulative fatigue usage factors, acceptance criteria, ASME codes and addenda, functionality impact of EPU on Generic Letter 89-10 for motor operated valves and Generic Letter 95-07 for pressure locking and thermal binding of power operated valves.

The license's EPU evaluation does incorporate an improved leak before break criterion that allows elimination of postulated primary loop pipe breaks in the original design basis analysis. And after elimination of the primary coolant loop breaks by the application of the leak before break criterion, the existing design bases analysis for NSSS piping and components are bounded for the EPU evaluation considering postulated smaller branch line pipe breaks.

The specific areas where the Staff requested additional information included the main steamline and feedwater line flow-induced vibration due to increased flow rate, quantitative analysis and results for the Beaver Valley Unit 1 replacement steam generator, calculation of cumulative usage factors for the vessel flange closure stubs, considering 10,400 cycles as opposed to the 18,300 cycles of the design bases.

With respect to flow-induced vibration in particular, the main steamline and feedwater piping are instrumented at critical locations to monitor vibration levels at current rate of power and during power ascension up to full authorized EPU power level. The vibration monitoring and the collective data will be evaluated according to ASME Standard and Guide 2003 Part 3.

The flow-induced vibration effect on the steam separators and the steam generators is expected to increase somewhat for EPU conditions. Based on the licensee's response to the request for additional information to the request for additional information, the potential for flow-induced vibration of the steam separator is minimized due to its high stiffness resulting in a high natural frequency combined with a low velocity. And we heard about it, it's about 4 feet per second or so of passing flow. And past inspection performed for steam generator, moisture separators on operating PWR, pressurized water reactor plants have found no indications due to flow-induced vibration fatigue.

The flow-induced vibration on the U-bend tubing and the steam generators is within allowable limits. In other words, the fluid-elastic instability ratio was maintained less than the limit of 1.0. And peak stresses are less than the material endurance limit.

There were some pump and valve modifications to accommodate the EPU operations. These are relatively minor considering the 7 percent EPU power uprate. The charging and safety injection pumps have been modified to improve their high head performance and flow rate.

The tolerance settings for the main steam and safety valves and reactor coolant pressurizer safety valves have been adjusted.

New trim was installed in the feedwater regulating valves in Beaver Valley Unit 1 and those valves were replaced at Beaver Valley Unit 2.

Fast acting main feedwater isolation valves were installed in Beaver Valley Unit 1 similar to those in Unit 2.

And based on the Staff's review our conclusion is that the calculated stresses and accumulate usage factors in the NSSS and balance of plant piping and components are bounded by the original design basis analysis with the application of the leak before break technology, such that the postulated primary loop pipe breaks are eliminated.

The potential for flow-induced vibration is not increased for steam separators and the steam generator tubes at EPU conditions.

The main steamline and feedwater line piping is monitoring to remain within the allowable limits in accordance with ASME OM3 code guidance.

The NRC Staff reviewed the licensee's assessments related to functional performance of safety related valves and pumps at Beaver Valley for EPI conditions and based on that review the licensee has adequately addressed the EPU effects on safety related pumps and valves. And as a result, the Staff concludes that the licensee has demonstrated that the safety related valves and pumps will continue to meet their NRC regulatory requirements during EPU operation at Beaver Valley.

So we'd be happy to answer any questions you might have.

CHAIRMAN DENNING: I think this is pretty clean. Any questions? Okay. Thank you.

MR. SCARBROUGH: Thank you.

MEMBER WALLIS: Are we gaining time here?

CHAIRMAN DENNING: Oh, yes, we're gaining time.

We're going to go ahead with the next presentation.

An NRC presentation. By Gregory Makar.

MR. MAKER: Good morning. I'm Greg Makar. I am in the Division of Component Integrity. And my branch works on issues of steam generator integrity and other chemical engineering topics. And this morning the Staff reviews in five areas: Low accelerate corrosion, steam generator tube integrity, the steam generator blowdown system, chemical and volume control system and finally coatings.

Our review of flow accelerated corrosion begins with determining of the licensee has evaluated the changes due to the extended power uprate on the parameters like temperature, velocity, moisture content that are the keys in controlling flow accelerated corrosion rates. They did this and based on the known effects of this parameters, you see as Mr. Grabski explained, cases where the corrosion rates would be expected to increase and some where it would be expected to decrease.

MEMBER WALLIS: The boron content has no effect on any of this?

MR. MAKER: Excuse me, boron --

MEMBER WALLIS: Boron doesn't seem to be a parameter that comes into this at all?

MR. MAKER: No.

MEMBER WALLIS: This is simply because it's ignored or because it's proven to have no effect?

MR. MAKER: Well, if it changed the pH, say, then if the pH decreased because of it. But as I understand it, the pH does not decrease significantly enough to change the corrosion rate in this case.

So to satisfy that they were scoping things in properly, there's also the question of scoping things out because you want to keep your resources focused where they're needed. And there are criteria. And all of these cases we're going primarily by the EPRI guidelines on flow accelerate corrosion programs. That scoping out components based on things like temperature below 200 degree Fahrenheit, the chromium content being 1 and a quarter percent or higher. And this they're doing according to the EPRI guidelines.

DR. BANERJEE: Does NRC have any programs which independently check EPRI sort of guidelines and things?

MR. MAKER: No. No, computer models or programs.

DR. BANERJEE: Even the research programs or whatever?

MR. MAKER: No.

DR. BANERJEE: How do you know that -- do you audit it in some way other than just take their data or what?

MR. MAKER: The way that we evaluate this is by -- the NRC in the past was involved in developing a response flow accelerate corrosion and understanding the parameters that are the key influences on it. And I think at that time we did have research programs to determine those. I think we were in the lead at that time and helped lead industry toward a resolution and a development of the computer based programs. And followed and participated in research efforts to understand all the parameters and their influence.

DR. BANERJEE: So when did that effort terminate within RES or wherever in NRC it was?

MR. MAKER: I'm sorry. I don't know the answer to that.

DR. BANERJEE: Was it a long time ago or recently?

MR. MAKER: Well, several -- I don't know. And currently we sent -- for example, we send people to training to understand how CHECWORKS is used.

DR. BANERJEE: That's an EPRI training?

MR. MAKER: Yes. But the effect of these parameters on low accelerated corrosion is fairly well understood now. And I think the most value on making sure the licensees are following these programs and using -- skipping ahead a little bit. But the computer models for plants are one factor. But really the key is actually inspecting systems at repeatable locations and developing data so that you can then trend and determine corrosion rates. That allows you to make decisions about future inspections and replacement repairs. And also it improves the quality, the predictive ability of the model.

DR. BANERJEE: Does this apply mainly to components that can be inspected then or there components which inspection is difficult?

MR. MAKER: Yes. It should apply to all. There are cases where it's difficult to inspect components. And in that case what the licensees may do is go to a secondary inspection or a testing technique such a radiography, which isn't as good as ultrasonic testing. Or they may have another similar system behaves, is nearby, say, same type environment which behaves in the same way. And they'll use that --

DR. BANERJEE: So you're talking mainly of the secondary side rather than the primary side?

MR. MAKER: Yes. Yes.

DR. BANERJEE: None of this concerns the primary side then? Okay.

MEMBER WALLIS: Because of the materials that are used there, is that it, really?

MR. MAKER: Well, yes. Once you get to 1 and a quarter.

MEMBER SIEBER: Single phase flow.

MR. MAKER: Yes. And you need moisture fort his to occur.

MEMBER WALLIS: Moisture isn't

necessary. You've got this in the feedwater line.

MR. MAKER: Sorry. Yes.

MEMBER WALLIS: I mean --

MR. MAKER: And there's also a temperature --

MEMBER WALLIS: Okay. I guess --

MR. MAKER: Well, some things like velocity, as you increase velocity you would expect corrosion rate to increase. There are other effects like temperature where there's a peak around 300 degrees fahrenheit and then beyond that then it start decreasing.

MEMBER WALLIS: Well, CHECWORKS is well established, and it's updated from time-to-time. So throughout industry, isn't it? This is why the NRC has stopped --

DR. BANERJEE: Also I suppose from a safety point of view this is not incredibly significant.

MEMBER WALLIS: Right.

MEMBER SIEBER: Not safety related.

MEMBER MAYNARD: The NRC does perform periodic inspections at the site on the flow accelerated corrosion program.

MEMBER SIEBER: Sure.

MEMBER MAYNARD: So it's not something that's just left out.

MR. MAKER: Plant audits, yes.

MEMBER MAYNARD: Yes.

MR. MAKER: So following on that idea, the importance of the inspection, this is really their -- a key to their program is ultrasonic measurements at repeatable locations to develop corrosion trends. And therefore, the combination of the required thickness of the components, the measured thickness and the corrosion rates are the key to future inspections and replacement repair decisions. And the CHECWORKS computer program is one tool in managing this program.

Next slide, please.

So they are updating the models. I've done that for the EPU. It does predict some increases in corrosion rates in some cases, decreases in others.

In cases where there's a large increase, it happened to be a system with a very low corrosion rate to start with. And that was an example Mr. Grabski showed.

So considering all these things, we concluded that their program will continue to manage the flow accelerated corrosion effectively after the extended power uprate.

Next please.

Address steam generator tube inservice inspection. Our guidance here is some -- we have standard review plans on materials and also for inspection we're focused mainly on the NEI 97-06, which also refers to the more detailed EPRI steam generator program guidelines. And as you've heard, the steam generators in Unit 1 were replaced.

There are two key materials upgrades; the thermally treated Alloy 690 tubes and also the stainless steal tube support plates, which these two things have a big effect on types of degradation that are observed and the rates of degradation, initiation and propagation. There are also some additional design factors like the shape of the holes in the tube support plates, the type of the antivibration bar design. And all of these are major improvements in steam generators.

Now the temperature, and the temperature is one of the key parameters in causing degradation. That will remain within the range seen at other plants that have 690 tubes.

There is a possibility, as you

discussed, in tube vibration and wear. And there's been an evaluation that the likelihood for wear is low. But for our purposes we're looking at the fact that if there is wear, that is captured in the tube integrity program. That the inspections will see that they're required to evaluate that and monitor that in their operational assessments and their--

MEMBER MAYNARD: Has Beaver Valley either made their tech spec changes or committed to make the tech spec changes for the Generic Letter 06-01?

MR. MAKER: They have an application in house now that being evaluated.

MR. KAMMERDINER: If I could add something. This is Greg Kammerdiner from FirstEnergy.

We have submitted the license amendment request to adopt TSTF449 for both units.

MR. MAKER: So we're concluded for Unit 1 that their program will continue to manage degradation at uprate conditions.

Next please.

For Unit 2 they have the original steam generators with the milled annealed Alloy 600 tubing and both carbon steel and Alloy 600 tube support structures. The existing degradation mechanisms include several forms or several modes of stress corrosion cracking and also some small amount of antivibration bar where the cracking initiation and growth rates could increase based on the small temperature increase and also increases in flow and potentially sludge accumulation at EPU conditions. However, these changes are relatively small and still will remain within the experience we have at other operating plants. And we don't see this as a -- it will not degrade in anyway their ability to monitor, to detect and monitor degradation at uprate conditions.

And we also note that these steam generators have a couple of design features, improvements over a lot of the Alloy 600 plants, such as the heat treatment to stress relieve small radius U-bends and also shop pinning in the portion of the tube within the tube sheet. And these are things which are shown to retard the initiation of stress corrosion cracking.

The AVB wear rates for Unit 2 are measurable but low. But as with Unit 1, again, there are inspections performed to measure this and evaluate it.

We don't expect with these small changes and conditions any new forms of degradation to emerge as a result of the uprate. But, again, we're satisfied that their program will find them and will continue to be consistent with the guidelines at uprate conditions.

MEMBER SIEBER: I think one of the big factors is the chemistry control of feedwater. And Beaver 2 should do much better than Beaver 1 because it has a polisher, it has 1 years less life even though the capacity factor is better. And generally there's been good careful control of the chemistry. So I would expect to see lower rates of degradation than Unit 1 experienced through its lifetime.

MR. MAKER: Thank you. Yes. The importance of water in chemistry is really important.

MEMBER SIEBER: That's the key factor in my opinion

MR. MAKER: Next, please.

The steam generator blowdown system helps steam generator tube integrity by controlling the quality of the secondary coolant. The blowdown flow rates are not expected to increase as a result of the uprate because they're determined by some parameters that are not going to be effected. There is a repositioning of flow control valves due to decreased pressure. This will reduce the maximum achievable flow rate, but not be require. It will not reduce it below what's required.

So we conclude that this will not have an effect on the ability to remove impurities from the blowdown. And we also note here this is a system with potential for flow accelerated corrosion and it is in their FAC program.

Next please.

Chemical and volume control system. Several functions related to the water inventory and quality for the reactor coolant.

The heat exchange temperatures, heat exchangers are one of the key components. There are some slight changes in temperature increases and decreases, but they stay well within the -- well below the design values. And the heat exchanger pressures are not changing as a result of EPU.

Boration requirements continue to be met. And letdown flow rates, charging rates and nitrogen-16 delay times are not being affected significantly by this.

So, again, according to our Standard

Review Plan we concluded that this will be acceptable at EPU conditions.

Finally on coatings. Unit 1 coatings were specified according to the ANSI standard. We're evaluating compared to -- we have a Reg. Guide 1.54, there are ANSI standards that are called out in that. And we have a Standard Review Plan 6.1.2 on coatings.

Unit 1 coatings were specified according to ANSI N101.2. When Unit 2 coatings were specified, we now have the Reg. Guide which also referred to 101.2 as well as the newer ANSI standard on the quality of coatings.

And the licensee provided us with their uprate environmental parameters compared to the qualification test values for normal and design bases accidents showing that their bounded by those qualification values. And so we expect no effect on the adhesion or the degradation of those.

CHAIRMAN DENNING: I mean if there were any issues here in the painting areas, I don't think they're EPU issues. But I'm just curious, did you talk to management of these units about what the status is of their paints, whether there is observable flaking occurring in areas and potential problems there?

MR. MAKER: I didn't as part of the EPU. And I talked to our GSI-191 team members who are evaluating their coatings. Well, the debris issue which includes coatings. But they were not able to tell me the status of coatings yet.

CHAIRMAN DENNING: Okay.

MEMBER WALLIS: Well, it says coating failures are identified by inspection. I'd be curious to know have there been coating failures.

MR. MANOLERAS: Yes. This is Mark Manoleras, Beaver Valley, FENOC.

I own the coatings program and the coating engineer works for me. Our containment coatings actually have been in very good shape. If we identify a deficiency, it's put in our corrective action system. It's evaluated by that coating system engineer and then it is repaired.

We've had outside people come in and take a look at our coatings in response to the GSI-191 to make sure that what we believe is what the outside experts also believe. And we've gotten very good feedback on that, on our coatings, our containment coatings.

MEMBER WALLIS: Have you actually had to

replace some coatings?

MR. MANOLERAS: We've had to make very minor repairs to some coatings in containment.

MEMBER SIEBER: Those are typically scrapes --

MR. MANOLERAS: That's correct.

MEMBER SIEBER: -- as opposed to force or lack of -- somebody runs a cart into the wall, you can scrape.

MR. MANOLERAS: That's correct.

MEMBER SIEBER: And you have to repair that.

MEMBER WALLIS: So it's that kind of thing rather blistering or --

MEMBER WALLIS: Right.

MR. MANOLERAS: That is correct.

MR. MAKER: Okay. That concludes my presentation unless you have any further questions on these five topics.

CHAIRMAN DENNING: I think we don't. And I think Mr. Stubbs could now continue with the next presentation.

MR. MAKER: Thank you.

MR. STUBBS: Good morning. My name is Angelo Stubbs and I'll be discussing the review of the balance-of-plant systems.

Next slide.

Okay. In conducting our review we utilized Review Standard RS-001, which is a Review Standard for extended power uprates. And in general our review scope covered the balance-of-plant mechanical systems contained in Matrix 5 of the standard.

Scope of the BOP systems included over 20 systems, 6 major areas of review, the first of which internal hazards for which reviews were performed for the EPU impact on flood protection, equipment of floor drains, the circulating water system, missile protection, the turbine generator and pipe failures.

The second area, fission product control included reviews on the fission product controlling systems in the structure, the main condenser evacuation system and the turbine gland seal system.

For the next area, component cooling and decay heat removal we reviewed the spent fuel pool cooling and clean up system, service water system, react water cooling system, ultimate heat sink and auxiliary feedwater system.

Next slide.

The next area of review balance-of-plant included review of the main steam, main condenser, turbine bypass and consondate and feedwater system.

And the final two areas was the waste management system, which included gaseous liquid and solid radwaste and then the emergency diesel fuel oil storage and light loads were also reviewed.

In addition to our review of the systems I just mentioned, the staff also reviewed test considerations for certain BOP systems.

Next slide.

The Staff focused under review of auxiliary systems for which increased heat loads associated with the uprated plant might pose an increased challenge to the systems. The systems included the spent fuel pool coolings, the service water and ultimate heat sinks, auxiliary feedwater system and condensate and feedwater system.

In regards to the spent fuel pool cooling system, the Staff determined that the licensing bases evaluation, that is the current licensing bases evaluation which was performed at the power level of 2918 megawatts will be bounding for the EPU plant. But service water system and increasing the heat loads was not to have a significant increase in fact on the system. And they stable within the design temperatures of the system.

The Ohio River is the alternate heat sink for both of these plants and this capacity far exceeds the shutdown cooling and accident heat load requirements for the Beaver Valley units. And power uprate doesn't effect the temperature in that water for this.

The auxiliary heat water system is a system which required increased flow as a result of EPU at both units. In addition, Unit 1 has undergone a modification to add limiting flow venturies. And I'll discuss the EPU impact on these systems a little later when I address modifications that effected the BOP review.

And the condensate and feedwater system, there was minor modifications of the regulating valves. But the licensee evaluation showed that the condensate pumps had sufficient margin to operate at the EPU power and that sufficient flow could be provided to the system.

In addition to that the parameters of flow, pressure, temperature parameters will be monitored during the startup so that will help verify the performance also.

Next slide.

The modification. The modifications made to the balance-of-plant. These are I'd like to talk a little bit about. Take a few minutes to talk about.

The first was modifications to the high pressure turbine and the second is a modification to auxiliary feedwater system at Beaver Valley 1.

Next slide.

Okay. But in the case of the high pressure turbine in both units, the high pressure turbine is being replaced with an all reaction turbine. The Unit 1 modification has already been completed. They have calculated the maximum overspeed to be 118, which is below the acceptance criteria of 120.

The Unit 2 modification has not been completed yet and will be completed prior to operation at EPU. But at this time they have done the calculations for overspeed the licensee has committed to perform the appropriate overspeed analysis to ensure overspeed protection that's acceptable. Also as part of their operating surveillance tests verifies that the proper operation of the turbine overspeed trip protection system and that -- and they do this by demonstrating that the turbine works at or below the 111 percent at that.

MR. TESTA: Excuse me. This is Mike Testa.

I just wanted to clarify one thing for Unit 2. Now the way we're going to -- we're going to do a staged power increase. The existing turbine has additional capacity to it, around 5 percent. So we're going to elect to increase the power somewhat the existing turbine. But prior to going to the full extended uprate, we will replace the turbine with the reaction turbine.

MR. STUBBS: Okay. The auxiliary feedwater system, for this system in Unit 1 they're adding cavitating venturies. They're installing that as a modification to Unit 1.

At EPU the auxiliary feedwater pumps, which are now being credited for the feedwater line break and the loss of normal feedwater events, which is something that the current plant doesn't do.

Unit 2 licensing bases already credits these to AFW pumps. So this isn't a change to Unit 2. It's only a change to Unit 1. We did look at that. And the total required flow for the auxiliary feedwater system will be able to be met by any of the two pumps available out of the three that services that system. And there will be sufficient capacity for it to perform this intended function.

And the technical specifications, as I just mentioned, requires three alternate auxiliary feed pumps to be operable. And so this allows us to have a single failure and still require it to -- for the two events, the loss of normal feedwater and heat feedwater line break.

Next slide.

Okay. In summary, Staff finds that the proposed EPU to be acceptable with respect to the balance-of-plant areas based on:

The evaluations that was performed that we reviewed;

The commitments made by the licensee, and;

The tests that they will be performing.

So, is there any questions.

CHAIRMAN DENNING: Are there any questions? No.

Thank you very much.

MR. STUBBS: Okay. Thank you.

CHAIRMAN DENNING: Now what we'll do is we'll take a 15 minute break so we can prepare ourselves for the risk assessment presentations. And we'll be back by the clock on the wall at 10:00.

(Whereupon, at 9:49 a.m. off the record until 10:04 a.m.)

CHAIRMAN DENNING: We'll now come back into session. And our first presentation will be on risk analysis and its impact.

MR. KELLER: Good morning. My name is Colin Keller. I'm a supervisor of the PRA Group at Beaver Valley.

With me here today also is Bill Etzel to help answer any questions that the Subcommittee may have.

A little bit about myself. I've been in nuclear power for 24 years now at Beaver Valley, starting at the Shippingport Atomic Power Station and working through other engineering assignments through Unit 2 startup, equipment qualification and the last ten years I've been involved in PRA.

I'm here today to discuss the Beaver Valley EPU PRA models, one for each unit.

Next side.

And I'd like to talk about the elements

of the Beaver Valley model that were reviewed as part for this uprate. And also to talk about the resulting changes in core damage from these reviews.

Next slide.

The first element we reviewed was our initiating events. We found that from the extended power uprate there were no new initiators identified and also there were no significant increases in our initiating event frequencies as a result of the power uprate.

We also did a review of our success criteria. We used the MAAP code to perform these analyses to establish our success criteria. Also included setpoint changes in there due to containment conversion and new pump curves that were put in.

We found that new accident sequences were identified as a result of the power uprate.

We went on to review our component and system reliability. Comprehensive reviews of the equipment were performed. We found that systems will operate within their allowable limits. There was on the PRA failure rates or results. We will continue to use our existing monitoring programs to account for any additional system wear using

Maintenance Rule MSPI, flow accelerate corrosion.

We expect that our future model updates will capture any initiating event or equipment failure rate changes.

We also performed reviews of our operator response times for our human reliability analysis. The MAAP analysis was used to determine operator action times that are available.

Higher decay heat did reduce times for some of these operator actions.

The most important impacts were:

For operators to start aux feedwater given a solid state system protection has failed and no SI signal present;

Operator initiates a bleed and feed, and;

And there was a reduction in time to recover from a loss of shutdown cooling due to reduced inventory.

This is a listing of Unit 1's five most important operator actions. You see there was a reduction in time for two of those actions from the pre-EPU to the post-EPU. And as a result of that, there was also an increase in their human error probability for both of those actions.

The following table --

CHAIRMAN DENNING: No. Let's stick a little bit with this. You were done with this table, let's spend a little bit more time on the table.

MR. KELLER: Certainly.

CHAIRMAN DENNING: So the first item and the last time are the only ones where you have a significant change in your human error rates, is that right?

MR. KELLER: Yes. And as you can see, those are also the ones that saw a reduction in operator action time.

CHAIRMAN DENNING: Now this initiating feed and bleed, there's really a major time, difference in time, isn't there? Between 78 minutes and 29 minutes, is that right?

MR. KELLER: That's correct.

MR. ETZEL: This is Bill Etzel from FENOC.

Yes. In the pre-EPU case that was done with a hand calculation and it was based on steam generator dryout. For post-EPU feed and bleed was based on a 13 percent wide range level in the steam generators.

CHAIRMAN DENNING: So the big difference is really a matter of --

MR. ETZEL: Yes, in setpoint levels.

CHAIRMAN DENNING: Okay. Now I'd like to spend just a little bit of time on each of these, if you would. And give us some -- and that doesn't necessarily have to be a lot. But let's start with the first one here.

The first is starting the auxiliary feedwater system when you have no safety injection. And it does look like the 43 minutes certainly seems a substantial period of time to be available for that. You say the confirmation as it was simulator observation. So tabletop and simulator observations. So you've run through this in the simulator at post-EPU conditions?

MR. KELLER: That's correct. And George Storlis is here. He will speak to that.

MR. STORLIS: Yes, I'll speak. My name is George Storlis. I'm with FENOC.

And operationally we train extensively in the simulator environment. Both Unit 1 and Unit 2 have separate simulators, have a lot of exposure to simulator time.

One of the key elements of any failure

of solid state is manual backup by the operator and the supervisors that stand behind the team as part of the simulation. And 43 minutes is an extensive period of time, as you pointed out, for diagnosing a failure and then ultimately responding to that failure with manual actions. So I'm quite confident that we can make that 43 minutes.

CHAIRMAN DENNING: Okay.

MR. STORLIS: Probably in the realm of 2 minutes or less.

CHAIRMAN DENNING: Although you did have a big change in the human error -- I mean a big change in the human error probability. But I won't get into the details of that. I don't care.

Now let's look at, the second one obviously that's not an issue is the 24 hours.

The next is this portable diesel driven fans to cool the emergency switchgear rooms.

MR. STORLIS: Switchgear ventilation affords a rather large heat sink in that area. The portable ventilation is established to enhance existing cooling. And in the absence of cooling you have a period of time to set up and establish that flow.

MEMBER MAYNARD: Is the equipment pre-staged?

MR. STORLIS: The equipment is available and staged in a brigade area. And it's available.

CHAIRMAN DENNING: What about this, this fourth one? Can you describe that one to me? The reactor coolant pump trip, what's happening here.

MR. ETZEL: This is Bill Etzel from FENOC again.

Yes. That's just a simple reactor coolant pump trip on CCW, which is our component cooling water. And component cooling water supports thermal barrier cooling along with motor and cooling to the motors of the pumps, the reactor cooling pumps. So therefore we assumed that you have five minutes to trip the pumps with that, otherwise you would get an increased RCP seal LOCA due to high vibration.

MR. STORLIS: Again, this is an area where operator training is repeated over and over and over again to identify the absence of cooling water flows to the coolant pumps and the need for the five minute window to shut the pumps off to preserve the pump's condition.

MEMBER SIEBER: It seems to me you actually had an event like that at one time. Is that correct? Where you lost seal coolant?

MR. STORLIS: We did have an event where in loss of an emergency bus did transcend itself into a loss of thermal barrier cooling. And the pump was managed immediate to that and seal injection was reapplied in the pump.

MEMBER SIEBER: You actually didn't trip the pump, you reestablished the flow?

MR. STORLIS: Seal injection, that is correct.

MEMBER MAYNARD: This is I think a pretty common requirement or guideline for all the Westinghouse --

MR. STORLIS: That is a true statement, sir.

MEMBER MAYNARD: -- seals.

CHAIRMAN DENNING: Let's go to the next table them.

MR. KELLER: Okay. The next table is similar and is a listing of the operator actions for the Unit 2.

CHAIRMAN DENNING: Okay. Let's see, are there any here that are particularly -- okay. Well, let's start at the bottom one, the -- let's see. This is manual trip after the solid state protection system fails to automatically actuate reactor trip. So this is --

MR. KELLER: Directly from the bench port.

MR. STORLIS: Again, this is George Storlis.

The operator identifying conditions as displayed on what we call our first op panel. It enables early diagnoses of the need for trip along with a validation with the existing instrumentation. And the operator's license responsibility and legal responsibility to bring that reactor off line on manual action.

CHAIRMAN DENNING: Okay. Let's see --

MEMBER KRESS: Did you use a human error model to get these probabilities?

MR. KELLER: Yes. We were using the HRA Calculator?

MEMBER KRESS: HRA Calculator. That's the EPRI --

MR. KELLER: That is correct.

MR. ETZEL: We just switched to the HRA Calculator.

Bill Etzel, FENOC.

When we did this analysis we used the

SLIM methodology, success likelihood index methodology.

CHAIRMAN DENNING: Let's see --

MEMBER KRESS: And the confirmation with the simulators tabletop was just to show that you did it within that.

MR. KELLER: Ensure that we would be capable of performing those actions with the times that we don't have.

CHAIRMAN DENNING: Now why do you say tabletop there and simulator? Isn't this something that you would have verified with the simulator, validated with the simulator.

MR. ETZEL: This is Bill Etzel from FENOC again.

Yes. We were going through an update on our PRA model at Unit 1. And like Colin said, we were using the HRA Calculator. So we waned to -- since we were changing methodologies, we wanted to validated all our human actions. So we had simulator runs for the Unit 1 PRA model update. Similarly, when we go through the Unit 2 update sometime later this year, we will also do some simulator benchmarks.

MEMBER MAYNARD: But many of these are

things that you're doing as part of normal ops training anyway, aren't you?

MR. STORLIS: That is correct, sir.

MEMBER MAYNARD: This last one in particular, that's one of the first things you do when you have an issue is to check it and there's more than one person doing that, too.

MR. STORLIS: And that is absolutely correct. We're practiced on these in the simulator environment repeatedly.

MR. SENA: Again, this is Pete Sena. The indications available to the operators at Unit 1 to take the actions such as manually tripping the reactor in the event of a first out indication for the need for a trip is virtually identical at Unit 2. So the actions are the same, the training is the same and the indications are the same. So you can translate the simulation walkthrough that we've done at Unit 1 into Unit 2 through the tabletop method and be confident that the times are identical.

CHAIRMAN DENNING: Yes. It is interesting, though, that you seem to have some significant differences between the two units as to what the risk important operator actions are, or am I misinterpreting the similarities here? Is that true?

MR. KELLER: There are some differences between the units, yes.

MEMBER WALLIS: These are all errors of omission where the operator fails to do something?

MR. KELLER: That's the probability that we've failed to accomplish that action.

MEMBER WALLIS: Do you somehow put in potential errors of commission by misdiagnosing something and doing the wrong thing? Does that appear in your PRA at all.

MR. ETZEL: This is Bill Etzel from FENOC.

Mostly they are failures of omission in that he does not perform this action as opposed to doing the wrong action and making things worse.

MEMBER WALLIS: Are there some items of commission that would be affected in some way by the power uprate in that there will be a little more going on or more likelihood to make a mistake or something like that? I don't know you assess that, but conceivably in could be a context which is more likely to produce an error.

MR. ETZEL: Yes. This is Bill Etzel again.

That's a possibility and hopefully through the simulator training and just normal time in the control room will help prevent that.

MEMBER WALLIS: Fix that up during simulated training. You observe and see if as a result of the EPU there's more tendency to make some mistake, and then you correct that in some way? Is that the way you find it? You do it by training in the simulator?

MR. ETZEL: Yes.

MR. STORLIS: And this is George Storlis.

With regards to the structure of the OP, operating procedures, the team concept in the control environment, the identification of a potential error being made is identified and corrected before the committing of the act. So from an operating perspective the confidence in the team, the confidence in the training, the confidence in the practice of simulation and EOP network provide a high level of assuredness of proper actions.

MEMBER MAYNARD: The EOPs are also fairly good that even if a mistake is made or there's multiple things going on, getting you back, prioritizing and taking care of the issues.

MR. STORLIS: That's correct. The response not obtained columns and so forth that structure a pathway to success is very high.

CHAIRMAN DENNING: And I think if you identified in your simulator training a place where people were making errors of commission, then you'd correct something rather than putting it as a probability failure in a PRA.

MR. KELLER: That's correct.

CHAIRMAN DENNING: So it's hard to identify them, Once you do, then presumably you'll fix them.

MR. KELLER: Yes. You want to reenforce the training so we would make sure that we'd meet these times.

MR. STORLIS: Either in robust barriers and the like to assure that if there is a likely error condition that it's remedied either by physical barrier or other means.

CHAIRMAN DENNING: Okay. Proceed.

MR. KELLER: Okay. Thank you.

Next slide.

In regards to the operator response times, we did do a validation of the operator times to complete these actions through combinations of tabletops, discussions of simulator training or observations. And the operator actions with small amounts of time available can be performed within the time that is available.

MEMBER WALLIS: "Can" is a big --

MR. KELLER: I'm sorry?

MEMBER WALLIS: "Can" is a big word. I mean can with probability of zero or one? You think it can be performed with high probability or something.

CHAIRMAN DENNING: Well, he has exactly the probabilities on this table.

MEMBER WALLIS: He does, I know. But --

CHAIRMAN DENNING: These are three significant figures.

MEMBER WALLIS: I know. So it's really it will be performed or likely to be performed.

MR. KELLER: Likely to be performed. That's probably yes.

MEMBER WALLIS: Right. There's some things I can do, but without much probability.

CHAIRMAN DENNING: Likely would be a very PRA term.

MR. KELLER: I understand. Likely to be performed.

Next slide.

We also did a review for shutdown risk conditions. We found the EPU has no unique or significant impacts to the shutdown risk. There'll be no changes to shutdown operations to our safe shutdown risk assessments.

Next slide.

Summary for Unit 1 is shown here for the total core damages from pre-EPU to post-EPU and with a breakdown of internals, externals and fire and also it shows the differences for the total LERF. And the changes in risk are well within the guidance provided by Reg. Guide 1.174.

MEMBER MAYNARD: One new piece of equipment that you put in was the main feed isolation valves, How was that treated? Did that end up with positive credit, negative credit relative to the PRA. Because a new piece of equipment --

MR. KELLER: Yes. You do have some additional failure probabilities with that and also with the cavitating venturies. There is a probability that they could plug. But overall for the sequences, and Bill correct me, where main feedwater was involved there was not a huge impact from those additional failure rates.

MR. ETZEL: That is correct.

MEMBER MAYNARD: On the main feed isolation valves are you using an existing design that's been out there proven or is this --

MR. ETZEL: This is Bill Etzel from FENOC.

We have these similar valves installed at Unit 2, so we use their failure rates and apply them to Unit 1.

CHAIRMAN DENNING: Now let me ask an embarrassing question.

MR. KELLER: Yes, sir.

CHAIRMAN DENNING: Maybe an embarrassing question. And that is, you know, we recognize that there are changes in risks that aren't quantified by the way we treat CDF and LERF, particularly as far as radionuclide inventory is concerned. I mean, the risk is going to increase with no changes in CDF and LEFT, you're going to see there is a true increase in risk of at least a percent associated with --

MEMBER KRESS: Sixteen percent.

CHAIRMAN DENNING: -- this.

MEMBER KRESS: Two plants.

CHAIRMAN DENNING: Two plants. Well, I'm

not sure that that's still eight percent per, Tom. But in any event, we have had other applicants who have said okay, we want to make sure that the risk is not increased, and so we look to see what aspects of our PRA indicate things that we could fix that would actually reduce the risk or maintain the risk.

And I realize, of course, you changed the generator on Unit 1 and there's been probably a decreased risk associated with that. But as far as just looking at the major contributors to risk and recognizing the potential benefit that's associated here that certainly is worth doing, but did you look to see are there things that at this particular time we might change so that indeed we're not increasing the risk?

MR. KELLER: Yes. We have looked and we actually have some recommendations based on that. We've looked at things like potentially going out and adding additional methods for RCP seal injection. There was a recommendation also to, I believe it was restructure an EOP to gain some benefit towards large early release frequency.

And, Bill, there were two other modifications for each unit we were also looking at?

MR. ETZEL: This is Bill Etzel from

FENOC.

Yes. We also looked at increasing seismic ruggedness. We have at Unit 1 block walls on our emergency batteries. So we're looking at increasing seismic readiness of those block walls.

Also putting some fire barriers around our HVAC fans in the cable vault and spreading area.

CHAIRMAN DENNING: And has management agreed to any of these upgrades or made a commitment to these at this time?

MR. KELLER: At this time our plans to take those to our plant health committee at site and to get them evaluated and go forward from there. See if they'd --

CHAIRMAN DENNING: What's the committee you said?

MR. KELLER: Called the plant health committee.

CHAIRMAN DENNING: Plant health committee?

MR. MANOLERAS: Yes. This is Mark Manoleras from FENOC.

Our plant health committee is comprised of basically the management team at the site. Each project is presented to the plant health committee and it's weighed on its benefit and risks to the station and then will be implemented in course; ranked and implemented in course.

CHAIRMAN DENNING: Yes.

MR. ETZEL: And this is Bill Etzel from FENOC.

We did present the alternate RCPC seal injection system to the plant health committee already.

CHAIRMAN DENNING: And has a decision been made on that at this point or is that --

MR. ETZEL: Yes. We have had positive feedback on it.

CHAIRMAN DENNING: Yes.

MR. KELLER: A decision was made whether to go and install it at this time.

MR. ETZEL: Yes. The decision was made was that we were going to take a look at options to actually implement those options and then estimates will be performed on those options. We will go to our next committee, which is our technical oversight committee, which takes a look at the technical robustness of the options and how those will be implemented.

So it's well along in the process to be

targeted.

CHAIRMAN DENNING: What are the criteria that the committee uses to decide whether they would undertake a safety improvement that effectively isn't providing economic benefit?

MR. ETZEL: Yes. We actually have a very detailed rating system. We went out and benchmarked the industry and took a look at basically industry best practice. And actually one of the significant contributors to identify a project selection would be an increase or decrease in risk. We actually have a very large portion of our process will actually look at the change in CDF. So it's actually a big contributor to selecting a project to be implemented.

CHAIRMAN DENNING: You know, that still didn't help me very much. I mean, I'm talking about some things here where there's no economic benefit to the plant, or at least the economic benefit isn't obvious of some of these safety related improvements that could reduce risk. And so the question is under what conditions would the plant management say, well, it really -- I'm willing to invest some money here to reduce the risk even though I'm not going to see an economic payback and there's no regulatory requirements.

MR. ETZEL: Yes. I'm sorry if I didn't answer that clearly. A reduction in that risk is one of the key contributors to ranking a project. It is probably one of the top three contributors to ranking a project.

CHAIRMAN DENNING: Thank you.

MEMBER KRESS: As a bit of a follow on to this question, does your PRA system have the capability to do a level 3 analysis?

MR. ETZEL: This is Bill Etzel again.

Currently we do not. We just have level 1 and level 2.

MEMBER WALLIS: With a follow up question again. I understand that management looks at decreasing risk as a criterion for endorsing a project. Presumably there's something on the other side of the balance which is the cost of implementing this. And I just wonder how much your management is willing to pay? Do they have some sort of a figure that says we're willing to pay so much for so much decrease in risk? Is there some kind of an economic that's understood in the plant or is it not? You don't have to give me the figures, but it seems to me in the end its cost benefit that's got to rule in the decision.

MR. SENA: This is Pete Sena.

When we go through the plant health committee there's a detailed ranking form, as Mark was speaking towards, as far as how we score a particular project. Some of the other criteria may be, for example, does the modification result in in improvement in radiation dose to folks doing work on the station. Other criteria would be, you know, a change in personal safety, a change in equipment reliability. So there are many factors.

Those factors are then accumulated and tabulated. And that is then weighed against all the other modifications that are proposed.

Now, out of a year we will go through and we will pick, perhaps, our top 12 or 15 projects to go implement to look a year ahead. But, again, we do have limited financial means, as every other utility does. So we have a specific set budget. But the ranking criteria does not apply to the initial cost estimate. It would then be categorized against all the other mods. And we have X number of dollars and how many mods do we want to do with that X number of dollars.

MEMBER WALLIS: And so you have to spend

your budget?

MR. SENA: We would spend our budget, correct.

MEMBER WALLIS: So there is no trade-off? It's just a question of which ones do you spend it on, is that it? That was an interesting economic viewpoint.

MR. SENA: Well, again --

MR. MANOLERAS: Well --

MR. SENA: Go ahead.

MR. MANOLERAS: This is Mark.

Again, we want to weigh all the factors for the selection of this modification. We may want to increase equipment reliability in an area, we may want to increase personal safety. So we do weigh all those facets when we select the modification packages.

MEMBER KRESS: Just out of curiosity, how far away is Pittsburgh from Beaver Valley's plant?

MR. MANOLERAS: It's approximately 30 miles.

MEMBER KRESS: Thirty miles?

MR. MANOLERAS: That's correct.

CHAIRMAN DENNING: Proceed.

MR. KELLER: Thank you.

The next slide is a similar summary for Unit 2 showing the same changes. And, again, the changes in risk for both CDF and LERF are below the thresholds for Reg. Guide 1.174.

MEMBER WALLIS: Reg. Guide 1.174 also gives you no incentive decreased risk.

MR. SENA: And, Dr. Wallis, if I may just go back to how we look at various projects we may do. One example to speak towards, for example, is we installed N16 monitors at Unit 2. We had them previously installed at Unit 1. But, again, this was a benefit to the station. Not a production benefit, but a safety benefit so that operators would have a key prompt indication of a potential tube leak. So, again, that is an excellent example of a mod that met our criteria to move forward with.

MEMBER WALLIS: Thank you.

CHAIRMAN DENNING: Yes?

MR. KELLER: Okay. And summary, all the PRA model elements were reviewed for impact and found that the increase in risk due to the EPU for both Unit 1 and Unit 2 does meet the acceptance criteria. There were small changes in operator times that were available for some actions, and additional equipment that was installed had a small impact on overall risk.

CHAIRMAN DENNING: Let me just state for the record, I mean I think it's fine for you to compare with Reg. Guide 1.174, but its applicability to power uprates is somewhat questionable. And I think that the way the risk analysis was used in the review is really in a slightly different way than applies 1.174 to a change in the licensing.

MR. KELLER: Since it's not a risk informed application?

CHAIRMAN DENNING: Right.

MR. KELLER: Okay. I understand.

CHAIRMAN DENNING: Well, not to say that it isn't interesting to look at.

MEMBER SIEBER: It's not a risk informed application. It's nice to have risk information.

CHAIRMAN DENNING: Right.

MEMBER SIEBER: And, for example, the PRAs the state of the art today, does not evaluate and assign risk numbers to how much margin that you're reducing.

CHAIRMAN DENNING: Right.

MEMBER SIEBER: And to me that's a significant thing, but we are not going to easily get to the point to do that. It's a tremendous amount of work. And that's probably off in the future in number of years.

MR. KELLER: That's all I have.

MEMBER WALLIS: Do you have some perspective on what's the effect of these power uprate on risk? I mean, this is a measure of safety and this is what we're here for, so we get some idea what are the consequences of an EPU. And I think that's useful. But it's not as if 1.174 is the rule that you're going to use.

MR. KELLER: Oh, agreed. But it is a measuring stick, yes.

MEMBER WALLIS: Yes.

MR. KELLER: Any other questions?

CHAIRMAN DENNING: Okay. I see no other questions. I think we're ready to move on to the staff.

MR. KELLER: Thank you.

CHAIRMAN DENNING: Thank you.

We're on the Staff's presentation on risk assessment.

MEMBER SIEBER: Risk evaluation.

MR. LAUR: Well, good morning. I'm glad to see it's still morning.

My name is Steve Laur. I'm in the NRR Division of Risk Assessment, Senior Reliability & Risk Analyst. I'm here today to discuss the Staff review of the Beaver Valley EPU risk assessment.

Next slide.

I'll give you the conclusion slide first and if that's all you want to hear, we can make this even shorter.

The licensee assessed the potential risk impacts of the extended power uprate. Our review concluded and agreed with the licensee that special circumstances do not exist that would rebut the presumption of adequate protection. So therefore, we have approved going forward with this proposed power uprate.

Next slide.

Just a reminder, I think you just mentioned this right before I got up here, but they are not risk-informed as defined in Reg. Guide 1.174. However, there is an applicable review standard 001 that basically describes the purpose for the risk information that the licensee provides.

First of all, to determine whether the risk is acceptable. But as I mentioned before, to determine special circumstances exist that would rebut the presumption of adequate protection afforded by compliance with regulations. And this is discussed in the Standard Review Plan, Chapter 19.

This has been said a few times yesterday and today, but I want to reiterate this. This is an 8 percent power uprate. The Staff has approved uprates on PWRs up to 17 percent and on BWRs up to 20 percent. And so far from the risk assessment and from other reviews we have yet to determine special circumstances.

Next slide.

One thing that's important in looking at a risk assessment using a PRA is what is the quality or pedigree of the PRA? Beaver Valley has two separate PRAs because the units were sufficiently different. These are full power seismic fire and internal events including internal flooding PRAs. And they calculate the risk matrix, core damage frequency and larger release frequency.

For other risks including other external events and shutdown risk, the licensee used qualitative risk assessment.

CHAIRMAN DENNING: Unfortunately, George Apostolakis isn't here to say what's a qualitative risk assessment --

MR. LAUR: Yes. I noted that. I appreciate that.

CHAIRMAN DENNING: That's okay.

MR. LAUR: PRA quality, these are uprates of the agency's IPE models, and in the case of the fire and seismic, IPEEE models that were submitted under Generic Letter 88-20.

They had an owners review on the internal events portion in accordance with the industry peer review guidelines in 2002 and they've incorporated the resolutions from those comments.

The seismic fire PRA models, we don't have an equivalent industry peer review process or standards. However, they were reviewed by the consultants that did the work. I take that back. They were reviewed by consultants when the IPEEEs were performed. And the NRC in the staff evaluation report found them acceptable for meeting the Generic Letter 88-20 purpose.

And so the conclusion that I made from all this is that the PRA is of sufficient scope, quality and level of detail to support this application.

We also conducted a very focused onsite

audit of the licensee's PRA last October. There were several purposes. One was to understand the risk of the EPU taken by itself. A second purpose was to check the quality of the PRA and the risk assessment that was done using the PRA and to understand and clarify some of the RAI responses in an onsite manner as opposed to multiple back and forth on the docket.

Let me go to the key findings. The key findings was that the licensee up to that point had not assessed the risk of EPU by itself. There were model enhancements and methodology changes and then modifications to the plant that were unrelated to EPU that were included in the post-EPU model which made the delta risk assessment not apples-to-apples comparison.

Also, as a result of the audit we identified the need to explain some apparently anomalous MAAP results.

Coming out of the audit the licensee actually identified a MAAP error and reperformed and resubmitted quite a bit of the HRA timing analysis. They also submitted a risk assessment that was more of an apples-to-apples comparison pre-EPU to post-EPU.

DR. BANERJEE: Which were the MAAP results that had to be explained? What type of results, do you remember?

MR. LAUR: There was a reactor coolant pump seal LOCA calculation for station blackout. Correct me if I'm wrong, I know it was station blackout. I think it was RCP seal LOCA that in most of the cases from pre-EPU to post-EPU timing decreased as you would expect. In one case it actually increased. And so we questioned that. And then on the audit we pulled the thread a little more, the licensee ended up getting Fauske & Associates involved in explaining how the MAAP code works, et cetera. And it turned out the actual timing increase was due to another change, it had to do with the accumulator setpoints. And therefore, it could be explained in terms of the thermal-hydraulics, which was not my expertise, but it could be explained in the fact that more accumulator water went in during the transient.

However, in the course of researching that they discovered a modeling error in the MAAP model that required redoing.

DR. BANERJEE: Do you recall what the error was?

MR. LAUR: They had the pressurizer surge line going into the top of the loop instead of in the middle of the loop.

MR. ETZEL: This is Bill Etzel from FENOC.

Yes. on the pressurizer surge line the MAAP code we had a loop sealed model where in reality we do not have one.

DR. BANERJEE: But why didn't it show up in the pre-EPU calculation and the post-EPU. I mean, the error would have been made in both, right?

MR. LAUR: Right. The error was a preexisting error to my understanding.

DR. BANERJEE: So why did it give this anomalous result?

MR. LAUR: I can't answer that. But I know in my review when we're looking at a table of timing changes due to EPU and you see all of them going in the expected duration, a little bit shorter, and one of them going longer, it causes you to question.

But as to why that wasn't caught earlier, I don't know.

MEMBER WALLIS: But the two aren't quite so connected. Maybe the result of this lead to a review of MAAP which showed up this error; I'm not sure the two things are connect.

MR. KELLER: Yes. This is Colin Keller.

That's correct, Dr. Wallis. The two were not related. The error was found in part of the review that we did to the NRC's --

MEMBER WALLIS: You were lead to look further at MAAP and then you found something -- okay.

MR. KELLER: Yes.

MR. LAUR: Right. I didn't mean to imply that this error was causing the anomalous result.

DR. BANERJEE: So why was there an anomalous result? Then we're back to --

MR. LAUR: Well, when I say "anomalous," it's apparently anomalous --

MEMBER WALLIS: But not really?

MR. LAUR: -- but the reason for the time getting longer in this one or two scenarios, I don't remember how many there were, had to do with changing accumulator pressure setpoints and level setpoints that resulted a change in addition to or actually opposite to the change caused by power increase. So that in this particular scenario instead of the timing getting shorter, this additional water from the accumulators actually caused it to be longer.

DR. BANERJEE: So it was a legitimate-- now you accept that as a legitimate finding?

MR. LAUR: Yes. Yes.

DR. BANERJEE: But at the end of it it allowed you to -- well, not allowed it actually initiated this review of MAAP which found an error. But that error had nothing to do with this?

MR. LAUR: That is correct. And the real point I was trying to make here is that they did review the MAAP analyses and resubmit them on the docket.

The other result out of the --

DR. BANERJEE: Was there any independent check of MAAP or audit of MAAP or was this what was done?

MR. LAUR: I don't know. The audit we did was not looking at MAAP. We're looking at very focused on the licensee's configuration control process for MAAP and for risk calculations and on specific areas that we had asked in RAIs that we didn't understand. And this was one of them. But I think there were two MAAP areas, and the one they were able to resolve right away and this one took a little longer.

DR. BANERJEE: What was the other area?

MR. LAUR: I'd have to look it up. I don't recall offhand.

DR. BANERJEE: Okay.

MR. LAUR: The other result, though, we did compare the licensee's procedure for configuration the PRA to the ASME PRA standard Section 5 and concluded it was a good process. They had virtually all the elements met for practicing the configuration control by procedure.

The licensee already covered the fact that the way we tend to assess the risk is to look at the various elements that make up a PRA and say what could be impacted. And I've got these combined in a couple of slides here. But this one talks about initiating events and equipment reliability.

The EPU does not result in any new initiating events. Even in the cases where an initiating event is modeled as a fault tree model of some operating system that fails during its mission time, the equipment reliability is not expected to change either. So therefore, those initiating events would not be impacted.

And for the same reason the systems that are mitigating the accidents are not expected to change because they're still operating within their same design limits.

Next slide.

Accident sequence and success criteria. The general accident progression, accident sequence progression did not change. In other words, the event tree models are the same. Now timing may be different at EPU conditions, but you don't expect to have to ask different questions in the event tree as a result of an 8 percent power uprate. And the licensee concluded that you don't, and I concur.

The success criteria for the most part stays the same. And I just want to talk about a couple of places where it didn't.

Station blackout is impacted slightly. If you have a station blackout and never recover offsite power, you're going to have core damage somewhat earlier. That translates int the time that the operator has to recover offsite power, which translates into a higher operator action failure probability and therefore core damage frequency. The licensee did include that in their post-EPU model.

The ATWS success criteria was impacted.

Addition of the cavitating venturies on Unit 1 means you can no longer mitigate a full ATWS event because you can't get full flow out of three AFW pumps. However, the PRA success criteria didn't change. And the reasons for that is that the licensee had conservatively not credited full flow in the pre-EPU model. And therefore, the success criteria is the same. The licensee reported no change in risk.

I pointed out in my safety evaluation that that's not correct. There is a change in risk. The change in risk would be if you had taken the conservatism out of the initial, the pre-EPU, and you'd actually get a delta. But I also know to looking at the information they submitted that ATWS is less than 1 percent on both units. Therefore, the max that could be would be a 1 percent. It would not change my conclusions.

CHAIRMAN DENNING: That really is interesting, though, in terms of just looking at delta risks where, as you quite properly pointed out, that making the conservative assumptions made it look like there was no change in risk whereas in reality there was a slight increase in risk.

MR. LAUR: That's correct.

CHAIRMAN DENNING: But I agree, it's a

negligible consideration.

MR. LAUR: The design bases loss of feedwater transient was picked up by one of the other branches and brought to my attention resulted in a request for additional information on how the PRA success criteria was impacted. It turned out it was not. And the licensee submitted realistic LOFTRAN and realistic MAAP calculations to show that in a realistic analysis that the success criteria pre and post-EPU does not change.

CHAIRMAN DENNING: Now, is this the success criterion that relates to two out of three aux feedwater pumps?

MR. LAUR: Right. The PRA from a realistic standpoint pre and post-EPU you only need one AFW pump for secondary side decay heat removal. Now in Unit 2 you need two steam generators because you have small atmospheric dump valves but as far as the AFW portion, which is what has been effected by the cavitating venturies, the realistic analysis shows that it does not change.

And then the final bullet here is actually the subject of a whole other slide, which is containment accident pressure credit for ECCS NPSH positive suction head.

Next slide.

This has a potential of impacting success criteria, so that's why I put it under here. I don't know how much you want me to go over this. I thought it was pretty well covered by the Licensee and by Rich Lobel yesterday.

CHAIRMAN DENNING: Yes, I think it was. So if you just want to kind of bottom line, feel free.

MR. LAUR: The bottom line is if you remember the two graphs that were respective of calculations before and after, there's a difference of about 30 seconds to one minute when they cross zero, in which I concluded there was an incalculable risk impact, delta risk impact, from crediting the containment accident pressure.

MEMBER WALLIS: Does all this go into the PRA then? I mean you have an actual evaluation of the change in the PRA as a result of crediting this containment accident pressure?

MR. LAUR: No.

MEMBER WALLIS: You don't?

MR. LAUR: Not to my knowledge. If you look at the absolute value of a contribution to risk, in other words not the change but what it would be, and the licensee indicated that a large LOCA and failure of containment isolation for example would be 1E minus 8. I don't have their model, but what I did look at was a failure on demand. If you use a bounding value for a failure on demand of a containment isolation valve, a typical common cause failure in a bounding LOCA of frequency of ten to the minus four, you're down to ten to the minus seven right there. So you're talking about a very low --

MEMBER WALLIS: No, granting there's containment overpressure is not really something that's necessary in order to bring the risk down. It's necessary in order to meet some other requirement.

MR. LAUR: That is correct.

MR. RUBIN: Dr. Wallis, that's correct. If I could just interject momentarily.

This is Mark Rubin, Branch Chief 1.

The reason this was looked at is because of the issues related to the VY power uprate and some of the concerns on granting NPSH over pressure and the fact that the Reg. Guide -- I'm sure Mr. Lobel talked about that previously. Because the Reg. Guide is under revision, a senior NRR management asked that we reflect on the potential risk impact to see if any existed on the power uprates and that in the future it be sort of looked at quickly, if all that's required, to validate little to no risk impact. And that's why this was looked at specifically.

But the conclusion, you're absolutely correct, has no real impact in this case.

MR. LAUR: And the point was already made yesterday, but we're not granting containment overpressure. That's the existing licensing basis.

MEMBER WALLIS: There's really no change. It's been granted before and there's almost no change in the requirements, so nothing has really happened here?

MR. LAUR: Exactly. That's what we concluded.

Human reliability. I guess in keeping with every other EPU that I've heard about, this is the major impact on risk, on calculated risk. EPU has a tendency to reduce times for operators to act. The change in the HRA due to EPU is not assessed directly by the licensee. What was done instead was a sensitivity study. And the reason for that was their pre-EPU timing was, as I mentioned, based on often grossly conservative hand calculations for the time. Their post-EPU they've upgraded to use MAAP on both units.

Secondly, the method they used cannot translate small changes in timing into realistic human error probabilities.

MEMBER WALLIS: But that's just what they do, isn't it? Isn't that what they do?

MR. LAUR: That's what they do. But that's--

MEMBER WALLIS: You're saying they can't do it meaningfully?

MR. RUBIN: This is Mark Rubin again.

Yes, I think that's what we're saying. Some of the HRA methodologies, especially the earlier ones we'll grant, as Dr. Apostolakis has shown us on many occasions. The small change is in timing. The model will calculate a difference in human performance or success rate, but it's really not a meaningful -- you have no confidence really in those small changes shown.

MEMBER WALLIS: What else are you going to do? If you're asked to calculate the CDF effect, you have to use some sort of HRA?

MR. RUBIN: Yes.

MR. LAUR: Yes.

MR. RUBIN: Certainly.

MEMBER WALLIS: And you're simply saying that this isn't a very good method. I think it's a little extreme to say it's not meaningful. It's maybe the best method available.

MR. RUBIN: What is meaningful -- well, certainly it does give a quantitative result. But what is meaningful is that the techniques allow us to identify the more important actions, look at the timing changes for those and see if they're significant and let us focus in risk case.

All we wanted to point out here is that we're in the areas of uncertainty, almost in the area of noise in the small calculational differences. But we do use the technology to help us focus in on the important human response actions and look at the timing changes on those.

MEMBER WALLIS: I think you ought not to use the word "meaningful" though. That might mean the wrong thing to some people. And you're just saying that there are uncertainties and these are very small changes anyway, and all that sort of thing. But you're still doing the best you can or the licensee is doing the best he can.

MR. LAUR: That's a good comment. When I say the "methodology," as I mentioned I used the success likelihood index method, but I'm not integrating that methodology. If you have a time reliability correlation, which I think is an artifact in some ways, but as Mark said you change time, you're going to get a change. And this method has a method on the performance there's a time. If you look at the SPAR-H model, they have discreet time steps ranging from not enough time to adequate time, to excess time. And the point I'll make on the next slide goes to more with symptom based procedures, it's almost a function of can you get to that step in the procedure and then do you have an error of omission when you get to that step.

So looking at the third major bullet, the way I assessed the risk was looking at the post-EPU core damage frequency and large early release frequency recognizing that the change in those is based on natural plant changes and on a sensitivity analysis for the HRA. Okay.

And I did ask the licensee in an RAI to validate important operator actions with short time frames. You know, demonstrate they can be done. In other words, they are not precluded. I understand you "can" meaning one to zero. What I'm saying is you haven't changed the time to where something that was maybe marginal but you could do it became precluded. And they did that and nothing fell into that category of being precluded.

So my conclusions focused on, like I said, that the actual CDF and LERF and whether or not special circumstances arose.

Next slide.

The licensee showed you a top five operator actions and they gave me whole pages of them, but if you look through them and sort them by importance, I tried to summarize them in two major categories. What shows up are depressurizing the RCS and feed and bleed cooling at both units and then some manual actions to, in the case of Unit 1 start auxiliary river water pumps and align them and Unit 2 solid state protection system failure so you have to start aux feedwater pump.

The licensee, as I said, validated these and all the other ones that could be performed. But just looking at the feed and bleed actions briefly. These are proceduralized, they're routinely practiced, they're performed in the control room with one minor exception. They take a relatively short time from two to ten minutes to actually perform the tasks. And they occur in response to symptom based procedures, not just the EOPs but also the functional restoration procedures.

So the last subbullet under there is what I was trying to say. It's really more of a function of how much time you have until you get to that step in the procedure as opposed to a slight decrease in the amount of time available.

And the other two actions up there are control room actions that are simple actions.

So we concluded that there was a minimal impact on EPU risk on the HRA.

DR. BANERJEE: What about switching to hot leg injection?

MR. LAUR: I don't recall that operator action, and I'd have to defer to the utility. That might be a good one for the utility to comment on.

MR. ETZEL: This is Bill Etzel from FENOC.

We currently do not model hot leg injection.

DR. BANERJEE: But you switch, right, to hot leg injection in the log term cooling scenario, right?

MR. ETZEL: Yes.

MR. DURKOSH: This is Don Durkosh. I'll be addressing that in the next presentation.

DR. BANERJEE: Okay.

MR. LAUR: Okay. External events, we've got seismic fires and other, which include high winds. There's nothing about EPU that would increase any of the initiating event frequencies or types of initiating events from these.

The quantitative assessment, since their PRA handles seismic and fires, demonstrated that a very small impact on the risk from those. And that comes from the fact that their seismic and fire PRA models are integrated with their PRA model. So human reliability increases and plant modification increases translate and propagate through those models.

And for other external events, the successive screening methodology that was used for their IPEEE remains valid and we conclude that would be a minimal impact on risk as well.

Next slide.

I don't have as many as the licensee had, but this shows you the post-EPU core damage frequency and large release frequency using their

HRA methodology with a MAAP realistic timing and that is what I used to conclude that there was no special circumstances. These are very small changes.

The increases include the modifications and the sensitivity analysis. These small. They meet the Reg. Guide 1.174 guidelines for being small, but it's not what I based my conclusion on for adequate protection.

Next slide.

The licensee did a qualitative assessment of shutdown risk using the questions in the Standard Review Plan, Chapter 19. And we agree that the shutdown initiating events aren't impacted. Times to boil times for operator actions are slightly decreased, but minimal impact on risk.

Finally, in conclusion the licensee assessed the potential risk from EPU. We concluded the EPU does not create special circumstances that would rebut the presumption of adequate protection and therefore we found this acceptable.

CHAIRMAN DENNING: Are there any questions?

Thank you. Good job.

MR. LAUR: Thank you.

CHAIRMAN DENNING: Okay. Now we're just going to continue on and we'll get into operations and testing starting off with human factors, I guess.

MR. DURKOSH: Okay. My name is Don Durkosh. I am a senior reactor operator currently licensed at Unit 2 and control room supervisor.

I also have with me George Storlis. George brings over 30 years of operating experience at Shippingport, Beaver Valley Unit 1 and Beaver Valley Unit 2.

A little bit about myself. I have 25 years of experience in the commercial nuclear power industry. I started my career with Westinghouse working in the engineering design analysis services area. I was the Westinghouse site manager at Beaver Valley and was in the unique position of kicking off this project and working with Mike Testa from a management perspective.

And I am licensed at Unit 2 and looking forward to raising power toward the end of this year at Unit 2.

The four areas that I plan to cover are human factors, training, our test plan and overview of our test plan and touch upon large transient testing.

From an overview perspective, the human factors impact of the EPU is minimal. There's a total of eight meter changeouts from a control room perspective. Six of them are related to the fact that we're replacing our accumulator pressure indicators with a digital indicator. And we also are replacing our containment narrow range pressure indicators as part of the containment conversion project. All eight of these meters have been replaced out at Unit 1 and on the Unit 1 simulator and in the process of being changed out at Unit 2.

Coming into the EPU project we were at an advantage in that in late 2002 and early 2003 Beaver Valley Operations staff undertook a major review of our emergency operating procedures. And e have substantially streamlines our EOPs and made them consistent with the Westinghouse ERGs. And, in fact, that's a project that I also worked.

So we had a very solid foundation for coming into the final portion of the EPU project having very streamlined procedures.

In the big picture here, the procedure changes that are coming out of the EPU project are rather minimally. They're primarily: Revise operating parameters, changes in limits and revise setpoints.

One area where the EOPs were directly impacted was the addition of an attachment that will require that the control room initiate a purge following a steam generator tube rupture. However, I do want to point out that that existing attachment already exists for purging the control room for a steamline break scenario. So in a big sense, it's a very minimal impact.

DR. BANERJEE: What are those two little things there? What was that interesting stuff.

MR. DURKOSH: Go back, but don't click on it.

What they are, they are backup slides. What I wanted to do, what I have here are examples of some of the normal operating parameters and some of the EOP setpoint changes. But I looked ahead at the NRC presentation and they have much more than I have, so I don't see any value going there, if that's okay with you.

CHAIRMAN DENNING: Thank you.

MEMBER WALLIS: What we could do is check that you and the NRC have the same presentation or there's no inconsistency.

MR. DURKOSH: All right. Click on it.

CHAIRMAN DENNING: Don't click it. Don't click.

MEMBER WALLIS: We'll trust you on that one.

MR. DURKOSH: All right.

Okay. I was at the Ginna presentation so I heard your feedback, what you really wanted to focus on; those areas that were potentially impacted. So, obviously, our action time, operator action time is a key issue so I wanted to address that.

Obviously with increased decay heat the available time to perform some actions are reduced. However, I do want to point out that the basic operator actions that we have to do remain unchanged. We are not implementing any new modifications that require new operator action times. And that's unlike Ginna where they did actually implement some modifications.

In most cases our action times have either remained the same or actually been extended to improve the overall process. And I do have a couple of slides where the case is actually reduced, and I'll talk about those.

During the course of this review we also identify procedure enhancements and we have incorporated those. Most notably, we did a complete review of our fire related procedures for Unit 1 and we did a major upgrade as part of the EPU project.

And action times are being revalidated. We've already talked about some using the simulator, using walkdowns, using tabletop discussions and field timing of operator actions in the field.

I do want to take a point. Colin had mentioned operator action time relative to the PRA. And for the scenarios that I saw, most of those are beyond design bases. So it gets you pretty deep into the emergency procedures and the contingency procedures. For instance, initiating bleed and feed. There's a loss of heat sink scenario which requires us to lose all of our aux feedwater pumps, not be able to use our main feedwater pumps, our startup feed pumps, our condensate pumps. So we're basically sitting as the steam generators are slowly drying out and getting ready to wait to initiate bleed and feed. So it's a pretty extreme scenario.

Okay. The next slide.

Okay. We talked about ECCS switchover to hot leg recirc. Ken had talked about and this question just came up.

At Unit 1 the existing time is 8 hours and when we go to uprate, that time will get reduced to 6½ hours.

At Unit 2 the current time is 7 hours and that will get reduced to 6 hours.

And in addition, at Unit 2 our design bases has us switch from straight cold leg recirc to hot leg recirc and back to cold leg recirc on a periodic frequency. That time rate now is 11½ hours and that'll be reduced to 9½ hours.

I think the question came up as to what the burden or impact is. Through our simulations generally within an hour or two of a large break LOCA scenario we are back into the emergency mainstream procedure called E1. And basically we are doing our preparations looking down the road and doing our preparations.

As was mentioned, approximately one hour before we will start taking steps to make sure we have AC power to the valves in questions. If we have any jumpers that require, we have those jumpers in position. And we're briefing on what actions have to occur.

And the time frame for actually

initiating switchover, at least I looked at the Unit 1 validation efforts on the simulator to initiate hot leg recirc. Coming into the procedure we're talking a matter of minutes. So those hot leg recirc procedures are relatively streamline. You're able to get in and get out very quickly.

DR. BANERJEE: I guess the impact would be if one was wrong in determining where the switchover time should be? If it was, say, three hours instead of 6½ h ours, there's no direct measure you have here. But it's not related to the uprate, it's in general this issue of not having a direct measure for the boron?

MR. DURKOSH: I agree. It's not directly impacted by the project.

DR. BANERJEE: Yes. The amount of time difference is not significant. All right.

MR. DURKOSH: Two areas that I would like to talk about is the tube rupture and isolating aux feedwater flow and the post trip fire scenario where if we did lose aux feedwater, we would want to restore it.

Relative to the tube rupture, one of the key operator actions is to isolate aux feedwater flow. I do want to point out that all of the EPU analyses that were performed were actually based on crew simulation data collected in 2002. So we had a solid footing for the analyses going forward.

And then as part of the EPU project in late last year we ran on the simulator with the new procedures that are being proposed, we had the Unit 1 crew go through and then we validated the fact that what we had done before we were able to meet.

For Unit 2 this EOP changes are in the final stages of being identified. There were tabletops that were performed and we are planning to do simulator validation later this year.

Next slide.

Relative to the fire scenarios, key action would be if you lost aux feedwater you'd need to reestablish it. I wanted to give you a positive message here. Relative to the Beaver Valley Unit 1 the EPU project established all of the critical operator action times. The entire set of fire related procedures were revised, streamlined and the walkdowns have been completed. So that validation effort is complete.

Relative to Unit 2, about 3 years ago our fire related procedures were updated. And it turns out that because that occurred in the midst of this EPU project, the aux feedwater critical times have already been incorporated in the procedures. So there's basically minimal work to do on Unit 2. Possible that any of the lessons learned from the Unit 1 procedures may get back to Unit 2. But we're not anticipating any major changes to our procedures; they're already there. And they've already included the operator action times that are appropriate for EPU.

The next slide.

Okay. Moving on to operator training. Basically we use classroom training of our design change packages. We'll go over our tech spec and licensing requirement manual changes. We'll go over any physical changes, procedure and setpoint changes. And then also we'll do simulator focus areas where if there is a change warning, a demonstration or hands-on training, we would do that. And for instance, the Unit 1 crews had a chance on the simulator to operate the new steam generator level control program following steam generator replacement. So the crews have time to basically get accustomed to the new control setpoint.

And then we always will continue our

transient response and EOP execution training.

And for startup and shutdown, we also use just-in-time training to get the crews focused in prebrief so that those activities go smoothly.

As we discussed over the last day and a half many of the modifications have been incorporated. So crew training has been going on here for the last couple of years as modifications have been made. And they'll continue up to our EPU uprate.

We do have plant specific simulators that we use, separate ones for Unit 1 and Unit 2. And the changes that we're talking about are primarily model and initial conditions. So there's no issue about going from current plant to EPU plant other than a matter of a couple of minutes to switch over the model. I know that question was raised at Ginna. So we do not have any issues being able to switch back and forth.

Moving on test plan. This is an overview of our test plan. Primarily consists of post modifications tests which, as I mentioned, many of them have already been performed and we'll continue doing them as the mods are made.

Our low power physics testing program

remains the same. There's no change there. What we are doing is we are collecting baseline data and then using that baseline data to support our power ascension testing. And in the power ascension testing we're planning on small increments. I have a couple of slides to show you of what our current plan is.

But basically we'll use the baseline data to make data projections. We'll collect data at steady state conditions and then we'll review that day and if we have any anomalies, we'll evaluate that and identify through our corrective action program what our next step would be.

So what I wanted to do here is here's kind of a profile of Unit 1 power ascension profile. As we discussed, we just completed our 1R17 refueling outage which involved replacing the steam generators. We have started up and we are operating at a 100 percent power currently. And during the startup process we did collect baseline data at roughly 90 percent and 95 percent. So we now have the data that we can use to predict where we expect to be. Following receipt of the safety evaluation report, we plan to uprate approximately a nominal 3 percent power uprate and we'll be using the baseline data to predict where the parameters should be so that we have a method to compare.

And we expect to operate the rest of the cycle at approximately 2770 megawatt thermal.

And then coming out of the new refueling outage, we expect to return to that power level and make two small moves approximately 2.5 percent each time collecting data, evaluating the data making sure that we're comfortable and then moving up to the ultimate power level of 2900 megawatts.

I have a similar slide for Unit 2. We are currently in cycle 12 with a 2R12 refueling outage plan for the fall. Our plans here is to come out of the outage, collect our baseline data at roughly 95 percent. Come up to our current license power of 2689, which is 100 percent power and then initiate shortly thereafter a nominal increase of 3 percent up to 2770. And our plan is to operate for the rest of basically the full cycle at 3 percent uprate. And then at the following refueling outage would be the next opportunity to go ahead and incorporate the high pressure upgrade at Unit 2 and basically come out of the outage at the referenced power level and again make two small moves up to the ultimate 2900 megawatt for core license power.

DR. BANERJEE: When do you have it all with robust fuel or whatever this new RFA? I don't remember.

MR. DURKOSH: I didn't understand the question.

DR. BANERJEE: When is the core completely peopled with this robust fuel?

MR. DURKOSH: We're there already.

DR. BANERJEE: Both units?

MR. DURKOSH: That's correct. As part of our extensive planning process for this phased implementation we started five or six years ago when we began to transition to RFA fuel. So both units today as we speak are 100 percent RFA fuel.

DR. BANERJEE: Okay. Thanks.

MR. DURKOSH: The next topic, I'd like to move on, is the topic of transient testing. So what should be considered when you evaluate the need for transient testing?

One thing that is very important is to evaluate the modifications and also to evaluate the NSSS control changes. And then based on that in your test plan ensure that you have adequate coverage for testing.

So there was a detailed evaluation that

was performed as part of the license amendment and follow up RAIs. As we indicated, each of the modifications will be fully tested. And as I've already mentioned, many of the modifications have already been incorporated and we're gaining operating experience with those modifications.

In addition, design engineering did an extensive owners review of the NSSS control supporting analyses. These are the operational transients to make sure that we would not have a reactor trip during selected design bases events.

And I think the key point that came out of that is there are no controller functional or logic changes. I know Vermont Yankee had somewhat of a fundamental logic change and transient testing may have been appropriate in that case.

We have no new control schemes. And our changes are primarily limited to setpoint changes that have been optimized for EPU conditions.

The conclusion from our earlier work is the aggregate impact does not adversely affect plant dynamic response.

Next slide.

Now Beaver Valley Unit 1 given the replacement steam generators, it was important that we did monitor control systems during startup. And I believe Pete mentioned yesterday that the feedback from the operators was very positive. So our control system operated as expected and in addition we did perform, and this was an area where we thought transient testing was important, we change our valve trims out, we did change our control operating setpoints and we had new steam generators. So there was a transient test performed, and actually it was completed over the last weekend. Basically we imputed a step change and we were monitoring the controller response.

If you can go to the backup slide. I had this data provided to me over the weekend. But basically this is the new control point, a nominal 65 percent. They imputed a signal that drove the controller down 5 percent and we had minimal overshoot. And then they initiated a similar transient up with minimal overshoot. So overall the control system worked just as planned. We easily met all the acceptance criteria. And this all happened within the last few days over the weekend. So very positive feedback on the test. The test and the control modeling worked just as expected.

As mentioned, large transient testing is normally a test that involves reactor trip at some high power. At Beaver Valley any turbine trip greater than 49 percent will result in a reactor trip. As I mentioned, there are no functional changes in the NSSS controls and the supporting reactor trip functions. So we do not believe large transient testing is necessary.

In addition, the simulation code, which was LOFTRAN, that we use supported the original plant. LOFTRAN has been around a long time. So my message here is the computer code and the model basically supported the original plant design and basically all Westinghouse plant designs. The startup testing confirmed that the plant matches the model, that computer code and model supports our current operational analyses, we have used it to benchmark our simulators, we use it in our non-LOCA analysis and we use it to optimize the EPU conditions. So no further benchmark testing was deemed necessary.

And again, my conclusion is based on the technical changes there's no large transient testing that will be necessary.

Slide.

So my overall conclusions in the

operations and testing area, the key take aways are:

Our procedure changes primarily involve operating parameters, limits and setpoint changes;

The power ascension process will ensure a controlled, closely monitored, very conservative approach to our new licensed power level;

And the modification in the NSSS control changes do not alter the basic design function of those systems, nor introduce a first-of-a-kind type change that will warrant large transient testing.

CHAIRMAN DENNING: How is the auxiliary feedwater flow test did following the changes that have occurred with the venturies?

MR. DURKOSH: Actually, those venturies were replaced I think in the previous outage. But generally what we do is we have an aux feedwater flow test, an operations surveillance test. And there were predictions on what the flow requirements are. And then we have tested the system.

CHAIRMAN DENNING: Yes. And actually test it and add water to the steam generator within those tests?

MR. DURKOSH: Yes. We normally will do that in the last stages of plant startup.

MR. HANLEY: Yes. This is Norm Hanley

from Stone & Webster.

And, again, when we implemented the modifications to add the venturies, we did use the OSTs to monitor the flow to the -- we also did a very detailed calibration with the venturie itself with the vendor. We did extensive tests to make sure the calibration and the predicted flows would match. We did an OST test where we did pump water to the generator and verify those conditions. And we also did an OST on the pump to verify the pump curve was matching what we used in the analysis.

MEMBER MAYNARD: And you do this test coming out of each outage, don't you?

MR. DURKOSH: That is correct.

MEMBER MAYNARD: I mean as far as the flow test, the calibration?

MR. HANLEY: That's correct.

MR. DURKOSH: That's correct.

Any additional questions? All right. Thank you very much.

CHAIRMAN DENNING: Okay. We will go ahead and continue to hear from the Staff.

You may proceed.

MS. MARTIN: Good morning. I'm Kamishan Martin. I'm a human factors engineer in branch of

Operator Licensing.

For our evaluation we reviews procedures, training in human factors, interface --

CHAIRMAN DENNING: I think you're going to have to speak louder. And is that mike working for sure.

The room's been all changed around and so we're having some trouble with the mikes. And you really have to get right up to this mike, too, I know from experience here.

MS. MARTIN: Okay. Can you hear me?

CHAIRMAN DENNING: Okay.

MS. MARTIN: The areas we reviewed include the training and human factors interfaces between the operator and the control room and in the plant related to performance.

These are the regulatory guidelines that I use in the evaluation.

The main areas that we use that we evaluated include the EOPs and the AOPs, the operator actions that are sensitive to the power uprate, the control room alarms, the SPDS and the training program and simulator.

As the licensee stated, the changes were slight modifications for parameter thresholds and the elimination to references to the BIT tech spec. This was eliminated because it's no longer credited as a source of boron -- borated water. Sorry.

There was one new operator action that was introduced due to the EPU and that includes the control room purge. And the one change was a change to another purge of the control room dealing with the steam generator tube rupture. I'm sorry. That's a new action.

The time reductions, some of the time reductions for operator actions were due to decay heat, but as the licensee stated, most of them stayed the same. There were only a couple that were reduced due to the EPU.

In Unit 1 all of the action times were validated through the simulator and through the walkthrough in the plant.

For Unit 2 the in plant operator action times were validated, but because the procedures aren't finalized at this time they only did a tabletop review. But the licensee has committed to validating the times on the simulator once the procedures are finalized. We determined this to be acceptable because of their commitment to validated operator action times on the simulator.

This is just a table with the operator action times that were most sensitive to the EPU.

In Unit 1, as I stated, all of them were validated. But in Unit 2 there was in particular that didn't have a margin between the time available and the time it would take the operator to actually perform this. But it hasn't been validated at this time because the procedures aren't finalized.

CHAIRMAN DENNING: Now let me see if I understand. Whose evaluation of action performance time was this, the 9.7 minutes for example in this first action? That's the plant says it can be done in 9.7 minutes or somehow you guys did it?

MS. MARTIN: No, the plant said that it could be done.

CHAIRMAN DENNING: Yes.

MS. MARTIN: And they performed a validation of this because it's in Unit 1 that it could be finished in 9.7 minutes.

MR. DURKOSH: Okay. This is Don Durkosh from Beaver Valley.

The Unit 1 operator action times were validated last fall on the simulator.

CHAIRMAN DENNING: Now, why don't you stay there just a second. And that is this action performance time versus time available, I mean obviously there's extremely small margin between 9.7 minutes and 10 minutes. Is that just a conservative value as to we're 99 percent confident that it can be done within 9.7 minutes or what's the difference between the 9.7 minutes and the 10 minutes there? Can you respond to that?

MR. DURKOSH: Sure. As was discussed in the non-LOCAs presentation from yesterday, the 10 minutes was the assumed operator action time for basically terminating an inadvertent SI basically precluding additional safety injection flow into the pressurizer. And they made an assumption of 10 minutes that operator action could be accomplished. And we confirmed that we were able to do it within 10 minutes.

MEMBER WALLIS: How much time is available?

CHAIRMAN DENNING: Ten minutes. And the 10 minutes is the rough criterion that you have of you have to do it within 10 minutes, right?

MR. DURKOSH: That is correct. And where it says "Time Available/Times used in the analysis," that's the specified time, that's the target time that we're aiming at reaching.

MEMBER WALLIS: I'm assuming the time available is longer than 10 minutes.

CHAIRMAN DENNING: Well, let me put a hypothesis down and then you can tell me why I'm wrong. Suppose this action in performance time if that was the mean time that it took staff to do this, then the probability of successfully doing it within this time would be about 50 percent. And I'm sure you're not telling me that. What is that 9.7 minutes telling me? That's not the mean time to perform it. What is it?

MR. SENA: This is Pete Sena again.

Dr. Denning, if I can back up slightly. If you recall during the non-LOCA transients for the inadvertent SI, the way we went through that transient was for the design bases assumptions we bias steam generator or correct in pressurizer level an additional 7 percent high from the norm and you put in these various conservatisms.

When we go through the design bases transient, the design folks that 10 minute window to get it done. So the operating crews go through the EOPs E zero, ES1.1 for inadvertent SI and all simulator crews went through the scenario and were able to perform that action within the 10 minute time period.

CHAIRMAN DENNING: So are you saying the conservatism is within the 10 minutes?

MR. SENA: Yes. That's correct. But again when we went through the analysis the way we qualified the acceptability of the analysis was through the qualifications of the downstream piping and the PORVs and not relying on the operator action time. That's how we precluded the event from going from a condition II event to a condition III event.

MEMBER WALLIS: Well, what does the 9.7 minutes mean?

MR. SENA: Well, that is the actual time that the operating crews completed the performance in.

CHAIRMAN DENNING: All of them or --

MEMBER SIEBER: The slowest one or the average?

CHAIRMAN DENNING: -- the slowest one? Yes.

MR. SENA: I cannot recall. I believe that might have been the maximum time, but let me get back to you. Let me phone call.

MEMBER WALLIS: The average, it isn't very good.

CHAIRMAN DENNING: Right. Other than the fact there's conservatism in 10 minutes, but then we don't have a real good feeling as to how much conservatisms.

MR. CARUSO: And let's ask once again if the operators don't get it done until 11 minutes, what does that mean?

MR. FREDERICK: This is Ken Frederick.

In a realistic sense it probably means that they will be closer to overfill. In the safety analysis world that means that we'll cycle the safety valve a couple of more times.

MR. DURKOSH: So Ken gave you the analysis impact. From a simulator perspective and all the training that we have received, I cannot recall ever challenging an overfill condition on this kind of transient. We have streamlined our procedures. We can get to SI termination very quickly within 10 minutes. And normally when we would stop the simulator at that point, we're nowhere close to being overwhelmed.

MEMBER MAYNARD: I think the importance of this is whether it ends up being classified as a condition II or condition III event. In reality if they don't get it done at all, you're still covered but your safety analysis just goes into a different wonder. But it's whether this is considered a condition II or condition III event.

CHAIRMAN DENNING: In this particular case.

MEMBER MAYNARD: Right.

MEMBER WALLIS: Does this chart come from a FENOC submittal? Is this something that you put together.

MS. MARTIN: I'm sorry, what was the question?

MEMBER WALLIS: Is this chart taken from the FENOC submittal or is it taken from--

MS. MARTIN: I put this chart together from information that was in a chart that they submitted that had more --

MEMBER WALLIS: I was wondering why we hadn't seen something like this before.

MEMBER MAYNARD: I thought this was discussed a little bit yesterday.

MEMBER WALLIS: Yes, I think it was. But we seem to be seeing it a different way now than we did yesterday.

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: Now it doesn't look so

good.

MEMBER MAYNARD: Well, again, I think we had a similar discussion yesterday, though, in that what happens if the operator doesn't get the action done.

MEMBER WALLIS: Yes.

MEMBER MAYNARD: And you're still covered with your small break LOCA or whatever other analysis is covered. It's whether or not this ends up being a condition II or condition III event. And that's what was discussed with one of the NRC presenters --

CHAIRMAN DENNING: Well, that certainly is true in that first one. I'm not sure that that's true for everyone of these.

MR. DURKOSH: Well, I can address the other ones if you'd like.

CHAIRMAN DENNING: Well, why don't you go ahead and do that?

MR. DURKOSH: Okay. Sure.

So in the case of Unit 2, as I mentioned, an isolating aux feedwater on a tube rupture is a key operator action. Previously the previous analyses used 9.1 minutes. Based on the extensive simulator crew evaluations from, I think

2002, they came up with 5.5 minutes as being a very representative time to perform that action. And that was prior to our streamlining of our EOPs.

And the action performance time was tabletopped at 5 minute.

I do have some data available to me from Unit 1 which I believe it was of the order of less than 5 minutes for Unit 1 on the actual simulator.

MEMBER WALLIS: So the now column here is the time used before, pre EPU, is it?

MR. DURKOSH: That's correct. It's in the current.

MEMBER WALLIS: Okay. So the word "EPU" should disappear from the title.

CHAIRMAN DENNING: Yes. And "isolate" is that just an implication as far as offsite doses from the steam generator tube rupture or does it have more dire implications?

MR. FREDERICK: This is Ken Frederick.

Yes. Each individual action in the tube rupture procedure and the analysis associated with that is trying to minimize overfill of the generator. So for these particular cases --

CHAIRMAN DENNING: Overfill.

MR. FREDERICK: -- the goal is not to

fill up the steam generator.

CHAIRMAN DENNING: Okay.

MEMBER MAYNARD: Okay. Some of this also is to keep you from wasting water to the ruptured steam generator there?

MR. FREDERICK: Right.

MR. CARUSO: And what are the consequences of overfilling the generator?

MR. FREDERICK: If you overfill the generator, then you lose iodine partitioning, which makes the offsite doses go up.

CHAIRMAN DENNING: Okay. I think we're content with this figure.

MEMBER WALLIS: I suppose we are. And just a little bit mystified.

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: If we're just comparing columns and you say you need 2 minutes and you got 2 minutes, that doesn't really help me much.

CHAIRMAN DENNING: Now, I don't think any of these are identified as important human actions from a risk assessment. Is that a true statement? Do we still have risk people here? Are they --

MEMBER WALLIS: I think we do.

MR. LAUR: This is Steve Laur again, NRR Division of Risk Assessment.

I don't know what the relationship between the design bases accident and the PRA is. But certainly cool down -- the action to cool down is one of the risk important operator actions.

I would point out that this a design bases discussion looking at the inputs from Chapter 15 and not a risk assessment.

CHAIRMAN DENNING: Yes.

MR. LAUR: And as I understand it, what the human factors are doing is verifying or validating that basically a go/no go criteria that you can meet the time whereas in the PRA risk assessment they use realistic timing and realistic scenarios and calculated the frequency of core damage sequences. So really it's not a comparable set of information.

CHAIRMAN DENNING: Yes. It does, however, give us a feeling as to what significance of margin in the design bases. But I think you're absolutely right, that that's probably the context that we ought to be interpreting this in rather than risk.

And I'm ready to move on to the next

viewgraph.

MS. MARTIN: These are the times that the licensee provided, the data that will be changed due to the EPU setpoints. This is a representation of the data that will change.

In the control room there will be no new displays except for as the licensee mentioned earlier, the SI accumulator should be upgraded to a digital display.

And all of the setpoints and displays will be normalized so that 100 percent remains a 100 percent and the actions don't change due to the renormalization.

For the SPDS, these are just the representation of the changes that will come. Nothing major. And this describes the change process that will be implementing the changes that we'll have.

For the simulator, as they mentioned previously, both the simulators have been benchmarked with engineering models. And they will be using the systematic approach training to train the operators for the --

CHAIRMAN DENNING: Thank you.

MS. MARTIN: This is just more general

information on the simulator changes and how they will cover the training for the simulator changes.

Our conclusion is that the licensee addressed the effects of the EPU on human factors and they have taken the appropriate actions to assure that the EPU does not adversely affect the operator actions. And we find these proposed changes to be acceptable because of their commitment to validation on Unit 2 and because of the issues that they've addressed.

CHAIRMAN DENNING: Very good. And I think we see no other questions.

Thank you very much.

And we'll move on to what is the last technical presentation, I think.

MR. PETTIS: Good morning. My name is Bob Pettis. I'm with the Division of Engineering. I'm filling in for Greg Galletti who was the technical reviewer for the Beaver Valley EPU. At present he's currently at Vermont Yankee and the license renewal inspection. So I'll do the best I can with what was the basis of his review.

As you're aware, the power ascension and testing program is covered under the SRP 14.2.1 and which we've had many discussions over the last several months.

The EPU test program should include sufficient testing to demonstrate that the SSCs will perform satisfactorily at the request power level. The Staff guidance considers the original power ascension test program that was done under the Reg. Guide 1.68 process and the EPU related plant modification, which most of the modifications fall into the area of plant systems branch which they probably have already provided their evaluation to you folks earlier today.

Staff guidance acknowledges that licensees may proposal alternative approaches to testing without adequate justification. We've centered around the large transient testing issue, but it's basically any departure from the original test program is reviewed as part of the technical justification for allowing those exceptions.

The Staff basis for requiring performance of testing including the large transient testing fell into the Reg. Guide 1.68 document which was basically established to ensure that there was a suitable test program at the original plant licensing phase that covered both the steady state and anticipated transients.

The objectives of Reg. Guide 1.68 were to familiarize operators with training, confirmation of design and installation of equipment, benchmark of analyses and codes and also to confirm the adequacy of EOPs.

One of the main objectives with 1.68 was also to provide necessary assurance that the facility could ge operated in accordance with the design requirements and validate any analytical models.

Under the Reg. Guide 168 there were a series of tests that were recommended back in the appendix. And two of those tests that were in the original 1.68 guidance were the so called large transient tests which are under discussion for the new plants today. And both of those tests that were required at original plant construction, again to validate analytical models in performance of a brand new plant.

Beaver Valley is planning on performing additional startup tests which were originally not part of the initial startup test program to maintain consistency with that of Unit 2. And I believe from what I could look at the SE, it had to do with the fact of the vintages of Unit 1 versus Unit 2 in order to have both plants be somewhat the same, the additional tests were included to make that happen.

Some of those examples included the secondary system vibration frequency and amplitude test, system expansion and restraint test, turbine plant system tests.

Beaver Valley will perform a series of post mod tests for plant design changes associated with the power uprate. A few of those are listed here. Replacement of main instrumentation, modification of HB turbine.

With respect to the transient testing issue, Beaver Valley like most others that have come before the agency, have elected not to perform the two large transient tests which are the MSIV closure and the generator load reject. Some of the accepted justification for not performing these tests for some of the previous plants were that the licensee's test program will monitor the important parameters during the power ascension test phase. And most of that occurs within 2½ to 5 percent increments where the licensee monitors the power ascension.

Tech surveillance and post mods will confirm the performance and capability of the modified components through tech spec testing, through normal QA and Appendix B type testing.

Operating history is a big factor that quite a few applications take credit for, which is listed in the SRP. And they've cited North Anna, Summer and Harris as similar plants that have undergone the uprates.

CHAIRMAN DENNING: Normally we tend to challenge the Staff in this particular area. But in all honesty, I don't think that there's any real serious concerns about large transient testing in this particular uprate.

MR. PETTIS: Okay.

MEMBER SIEBER: Percentage of power increase is really pretty small.

MR. PETTIS: I believe this 108 percent on Beaver Valley.

MEMBER SIEBER: Yes.

MR. PETTIS: But just to maybe reenforce that--

CHAIRMAN DENNING: And also looking at the lack of major modifications in --

MR. PETTIS: Yes. I was just going to mention that the technical staff in the balance-of-plant section identified that the balance-of-plant modifications don't warrant the need for the transient testing.

So based upon that part of the Staff's review, the Staff concludes that the EPU is satisfactory.

CHAIRMAN DENNING: Are there any questions? Thank you very much.

MR. PETTIS: Okay. Thank you.

CHAIRMAN DENNING: Well you never thought you were going to get away that easy, did you?

MR. PETTIS: No.

CHAIRMAN DENNING: Okay. Well, I don't hear anybody saying we ought to go to lunch. Let's finish out.

MEMBER SIEBER: If you want me to.

CHAIRMAN DENNING: Yes. Okay. So, first we'll hear from FENOC management and their wrapup.

MR. LASH: Again, I'm Jim Lash, Site Vice President. And I will be brief. I know I'm us and lunch.

The past two days I think our team as well as the NRC the presentations have concluded that the reviews have been detailed and there have been no safety issues identified and the Beaver

Valley approach is a conservative approach both from an analysis as well as a power escalation that we plan to employ at the station. And I assure you that the implementation of the power uprate will be performed safety and reliability using our plant modification process, our operator training program, our plant procedure modification processes and our adherence to the operating conditions.

That completes our presentation unless there are questions from myself.

CHAIRMAN DENNING: I don't see any questions. I would like to thank you and your staff for a very good presentation.

And as far as the full Committee meeting, we'll give you some more guidance as to what our expectations there. We have two hours there.

There was a little bit of duplication between some of the regulatory Staff's presentations and some of your presentation. I think that our guidance will be largely that we're going to focus more on your presentations in a few areas, and some of them are obvious.

MR. LASH: Sure.

CHAIRMAN DENNING: We're going to want

to certainly focus on the results of the accident analyses. But some other areas that aren't necessarily problems, but which ones has to look at like potential for vibrations and stuff like that. I think your story today was quite good on that. We'll have to abbreviate those.

And we'll give you some more guidance as to what the presentations.

MR. LASH: I appreciate that. I was going to ask you for that guidance. And I appreciate that.

CHAIRMAN DENNING: Yes. I think that rather than attempting to really lay it out at this meeting, Ralph will send you a message that kind of indicates how much time to figure on.

MR. LASH: Okay. Good.

CHAIRMAN DENNING: And in which areas.

MR. LASH: Very good.

CHAIRMAN DENNING: But there's nothing missing that I see, you know, that we're going to have to have additional things. It's really a matter of compressing and perhaps eliminating in some areas. And from the Staff's side, I think it's going to be an elimination in a lot of areas of some of the reviews that were of value to us to make sure that we saw that they had been comprehensive in their reviews and to see what their considerations were, but as far as the full Committee is concerned I think would be unnecessarily duplicative.

MR. LASH: Okay. Thank you.

CHAIRMAN DENNING: Okay?

MR. LASH: I do have another question, though.

CHAIRMAN DENNING: Yes.

MR. LASH: And that is just to confirm I think we've been checking all along. I don't believe we owe the Subcommittee anything?

CHAIRMAN DENNING: Let me just see if Ralph agrees.

MR. CARUSO: That's correct.

CHAIRMAN DENNING: Although it looked at some points like there might be, everything has been provided that we had asked for.

MR. LASH: Okay.

MEMBER SIEBER: Well, if Ralph has some of this typical --

MR. CARUSO: I'll be getting a copy of the WRP-2M. I'll send you off that today or tomorrow.

MR. LASH: Okay. Good.

CHAIRMAN DENNING: Okay?

DR. BANERJEE: And ATWS, I guess, but you have that.

MR. CARUSO: And I'll give you a copy of BACCHUS, too.

CHAIRMAN DENNING: Yes. Yes.

MR. LASH: Very good. I would like to thank the Subcommittee for allowing us to make this presentation of our power uprate proposal.

I'd also in your presence like to thank my team, which includes the subcontractors from Westinghouse and Stone & Webster for supporting us. The folks worked very hard. Their preparations were very thorough and I think that bore itself out in their presentations. So I thank the team as well.

That's it.

CHAIRMAN DENNING: Thank you.

MR. LASH: Thank you.

CHAIRMAN DENNING: And wrapping up for the Staff?

MR. COLBURN: I don't have any slides, so I can do that from here.

My name is Tim Colburn again.

And I'd just like to thank the Subcommittee also for allowing the Staff to make its presentation.

We reviewed the licensee's submittal against all of the areas in the Review Standard RS-001. We had a challenging review. There were numerous requests for additional information we provided to the licensee, but they stepped up and provided information every time we asked them questions that resolved all of our issues.

The Staff believes that the licensee has done a very good job in resolving the open items that we have along the review path and also in ultimately demonstrating that they can adequately and safely implement the power uprate of 8 percent for Beaver Valley Units 1 and 2.

And, again, look forward to whatever guidance the Committee would like to provide us on preparing for the full Committee.

CHAIRMAN DENNING: Very good. Thank you.

Any questions or comments from the Subcommittee?

Anything else we want to discuss before we --

MEMBER WALLIS: Well I think we should establish that we don't have any sort of outstanding questions or anything.

CHAIRMAN DENNING: Absolutely. Jack, do you want to start off?

MEMBER SIEBER: I would indicate that I worked at Beaver Valley for many years. So I don't have a bias one way or another.

When I read the application and through the SER, I found the application pretty easy to read, it was straightforward, easy to follow, legible, made sense. On the other hand, that was your second shot at it, I think.

In the SER it indicates a lot of requests for additional information that tell me that maybe the first application wasn't real complete.

On the other hand, all of that has been remedied and I think the document is in good shape. And I think the modifications that you intend to make on the plant are reasonable. The EPU level that you chose is reasonable because you still remain sort of in the middle of the pack as far experience is concerned. There are a number of plants like yours that operate basically with the same parameters. So you're not blazing ground in that area.

I was impressed with the presentations. I think that they demonstrated a good knowledge of analytical methods that were used and what they meant. And I congratulate your staff for that.

We had a discussion with some of your folks at the Ginna EPU and I noted that you've been sending people out to see what goes on in these meetings as a way to prepare for this meeting. And, obviously, you learned a lot because this meeting in my opinion went very well. The questions that we asked and that were important were answered well and with the analytical backup and operating experience backup. And I think those factors are important.

As far as issues are concerned, I don't see any issues that arise from this application. And I agree with the Staff's conclusions. And when we get an opportunity to vote on Rich's letter which he'll write, hopefully --

CHAIRMAN DENNING: I'd better. They don't pay me otherwise.

MEMBER SIEBER: -- I personally feel in the affirmative at this time with regard to granting the uprate.

So that would be my conclusion.

CHAIRMAN DENNING: Thank you.

Sanjoy, do you want to comment?

DR. BANERJEE: I think that the approach taken is quite conservative and lies within the bound of what has been done before. So I have no particular concerns.

I think I'd like to follow up a little bit more on the fate of the boron, which I will do when I look at the BACCHUS report. And a little bit more on the refluxing mod. But other than that, I have no major points. But the applicant doesn't really have to supply any more information at this time.

CHAIRMAN DENNING: Let me interject that with regards to the boron, I think there is more work that has to be done here. But not within the context of this EPU. And I have some recommendations that I will to the Staff about how I think that ought to be done there.

DR. BANERJEE: Far more generic issues which --

CHAIRMAN DENNING: Yes.

DR. BANERJEE: -- should not necessarily be a burden on the applicant.

CHAIRMAN DENNING: Yes.

MEMBER SIEBER: Yes, I agree with that.

CHAIRMAN DENNING: Graham?

MEMBER WALLIS: Well, I'm glad Jack made the speech, now I don't have to make it. I'm pretty satisfied with what I've heard.

I think in front of the full Committee you just have to present the key things and what are the main effects of the EPU as they effect the criteria for reactor safety; how do you meet those criteria. That's really the main issue.

Try to avoid a long discussion on PRA because, you know, the changes are so very small they don't effect the ultimate decision.

CHAIRMAN DENNING: Okay.

MEMBER WALLIS: I think there are some of these questions like the boron thing that we keep coming up with need to be resolved better at some time. But that's not something we should hang on this particular licensee.

Thank you.

CHAIRMAN DENNING: Tom?

MEMBER KRESS: I think it's all been said.

CHAIRMAN DENNING: Otto?

MEMBER MAYNARD: I think it's all been said, too.

CHAIRMAN DENNING: I think it's all been said, too.

We're adjourned.

(Whereupon, at 12:01 p.m. the meeting was adjourned.)