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Subcommittee on Power Uprates

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## ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

January 17, 2007

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# UNITED STATES OF AMERICA

# NUCLEAR REGULATORY COMMISSION

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## ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

## SUBCOMMITTEE ON POWER UPRATES

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WEDNESDAY,

JANUARY 17, 2007

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ROCKVILLE, MARYLAND

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The subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T-2B3, 11545 Rockville Pike, at 8:30 a.m., Mario V. Bonaca, Chairman, presiding.

COMMITTEE MEMBERS:

MARIO V. BONACA, Chairman
SAID ABDEL-KHALIK, Member
J. SAM ARMIJO, Member
SANJOY BANERJEE, Member
MICHAEL CORRADINI, Member
THOMAS S. KRESS, Member
DANA A. POWERS, Member
JOHN D. SIEBER, Member
GRAHAM B. WALLIS, Member

ACRS/ACNW STAFF:

RALPH CARUSO, Designated Federal Official

PANELISTS:

ASHOK BHATNAGAR, Senior VP, TVA
ALAN BILANIN, CDI
BOB BRYAN, TVA
BILL CROUCH, BFN Licensing Manager, TVA
RICK CUTSINGER, TVA
RICH DeLONG, TVA
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ROBERT PHILLIPS, TVA
JOE VALENTE, Engineering Manager, TVA
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GEORGE GEORGIEV, Piping and NDE Branch

MICHELLE HART, Accident Dose Branch

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KAMISHAN MARTIN, Operator Licensing & Human Performance Branch

MATTHEW MITCHELL

ROGER PEDERSEN

MARK RUBIN

THOMAS SCARBROUGH, Component Performance and Testing

MARTIN STUTZKE, PRA Licensing Branch A

MATT YODER, SG Tube Integrity & Chemical Engineering Branch

CHENG-TH WU, Engineering Mechanics Branch

# I-N-D-E-X

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

8:30 a.m.

CHAIRMAN BONACA: On the record. Good morning. So we get back into session and the next item on our agenda is Materials and Chemical Engineering and good morning.

MS. BROWN: Good morning. Excellent. Section 2.1 of the staff's safety evaluation addresses topics related to the reactor vessel, the internals and the reactor coolant boundary. For these topics the review at 120 percent is bounding for the 105 and is therefore applicable to all units. We should also note that the scope of some of these issues include evaluation through the extending operating period approved in the license renewal.

And just here looking for the presentation, we're in Materials and Chemical Engineering, Safety Evaluation Section 2.1.

CHAIRMAN BONACA: Now you're talking about Unit 1 and when you're talking about applicability to Units 2 and 3, you're making a presumption that all the materials are the same, the components are the same. Could you expand on that?

MR. CHERUVENKI: Yes. This is Ganesh Cheruvenki, Materials Branch. Unit 1 reactor vessel components, Units 1 and 2 and 3 are pretty much the same and the evaluation that was done under license renewal which is more bounding is applicable for the current application for the EPU for Unit 1 also.

CHAIRMAN BONACA: I can understand on the vessel and the internals but do you have any other --

MEMBER POWERS: I guess I don't understand the vessel.

CHAIRMAN BONACA: What?

MEMBER POWERS: I don't understand how the vessels could be similar. I mean clearly three must have been manufactured substantially later than one and two.

MS. BROWN: Bill, do you guys have any comments regarding the materials for the vessel?

MR. PHILLIPS: No problem, yes. Robert Phillips, TVA. Could you repeat the question please?

MEMBER POWERS: I can't understand how the vessel materials for one and two could be the same as three or very close to the same. I just assumed they were manufactured in different eras.

MR. PHILLIPS: Yes sir, they were. The Unit 1 was manufactured at the B&W plant in Alberta and 2 and 3 were contracted out to a company in Japan. So you're correct, but they were -- All three of them are codified, but they are similar but not identical.

MEMBER POWERS: And I'm told by the people that insist on researching these sections at nauseam that small trace differences in levels of alloying agent and copper and things like that make a big difference in their susceptibility to embrittlement.

MR. PHILLIPS: Yes sir, that's correct.

MEMBER POWERS: So how do we then infer from two and three anything about one?

MR. MITCHELL: If I can interject. This is Matthew Mitchell and I'm the Chief of the Vessels and Internals Branch in NRR. You're correct that there are trace element differences between the vessels, but those differences are known between the composition of the Unit 1 materials and the Unit 2 materials and the Unit 3 materials.

When we say that the materials are similar, they are sort of the same class of material. They're low alloy steel --

MEMBER POWERS: They're pressure vessel steels.

MR. MITCHELL: They're pressure vessels. Right.

MEMBER POWERS: Okay. They're not going to be that different.

MR. MITCHELL: Right. So the general behavior is taken to be the same and our general knowledge of the mechanisms is taken to be applicable as long as we know the differences which are known and categorized.

MEMBER POWERS: Now the guys that do heavy section steel come in and tell me that, yes, we ought to keep funding that research because there are all these things they don't know.

MR. MITCHELL: The things that we generally don't know in that particular area go out for higher and higher fluence levels, levels that many of the vessels have not yet seen. The BWRs tend to not reach those levels anyway due to lower exposure. So that's generally where our lack of knowledge occurs is at higher and higher fluence levels.

MEMBER POWERS: So if we just built BWRs, we wouldn't have to do all this heavy section steel research.

PARTICIPANT: There you go.

MS. BROWN: In your words --

CHAIRMAN BONACA: I would add also that many of the systems you listed there or to say the system affected, again are they identical between plants. You're looking at flow accelerated corrosion, so you're talking about even secondized site piping. Are they the same piping between Unit 1 and Unit 3? I mean you have to say something to us to have us accept that whatever it is you say this morning is applicable also to Units 2 and 3.

MR. GEORGIEV: This is George Georgiev and I did review the reactor coolant pressure system piping and actually the Unit 1 is, the whole line has been replaced with a better material approved by the staff, low carbon NG type of materials, and is stated in the safety evaluation that they have complied with all staff positions for looking in the other areas which might be susceptible to stress corrosion cracking.

For Units 2 and 3, that is not the case. They do have a basket of materials there. They have unstabilized three or four stainless steel. They have it placed in certain susceptible locations with the corrosion resistant -- material.

(Several speaking at once.)

MR. GEORGIEV: And also the one that, not the new material, they have used mitigated measures that are approved by the staff, has been reviewed. There is a lot of research and work on it and based on that basis, we have concluded that there is a reasonable assurance for the piping to do what it's supposed to do during this operating.

CHAIRMAN BONACA: Anyway, it seems to me that we should proceed with the presentation. This is a Unit 1 power uprate and then whenever we discuss Units 2 and 3 the case will have to be made that the materials are the same or similar, etc., and then the applicability because I don't think we can cover everything in broad brush and understanding the issues of how the components are built and what material is used there. So let's proceed.

MEMBER BANERJEE: Just from my understanding, your staff review you say covers not only Unit 1 at 105 but Unit 1 at 120, Units 2 and 3 at 120. So today's discussion is strictly related to Unit 1 at 105. You'll come back to us with 120 or not?

MS. BROWN: It was not our intent to come back to you on 120 unless you wanted us to. Because of the staff's review, our methodology and approach was similar and had already been completed when we looked at the 105. So the staff is available to answer any of these questions regarding similarity of components and materials today if you would like.

MEMBER BANERJEE: In fact, we are

reviewing everything at 120.

MS. BROWN: Yes sir.

MEMBER BANERJEE: This topic.

MS. BROWN: For this topic.

CHAIRMAN BONACA: It's clear. I know it's 120. The point I'm making here is just by placing (Cough.) front, Applicability Unit 1, Unit 1 at 120, it doesn't count. It seems to me that you have a burden as you go through to address the issues of materials, what materials there are in different piping or systems, etc., that you are covering under this and why is it applicable to Units 2 and 3. If you want to go through that, you can do that. Otherwise, you can just come at the next meeting where we will address 120 percent power for the three units and say we already addressed that because the representation is not sufficient like this.

MS. BROWN: Yes sir.

CHAIRMAN BONACA: Okay.

(Off the record discussion.)

MEMBER CORRADINI: Mario, just to -- So the way I interpret your comment which I would agree with is we're only looking at Unit 1. We're only looking at 105 and if we have questions about anything with 2 and 3 that comes at a later meeting at a later time, to be addressed later.

CHAIRMAN BONACA: All I'm saying is that we were ready yesterday. So a number of analysis is done at 120 percent power and we accepted that we had the ability to do 105. So by inference, we have reviewed those. Okay. In this particular case and this may be an example of other places in this presentation, a statement is being made that this evaluation covers all these power levels on all these units and the point I'm making is if you want to do so, okay, then tell us why it covers all these different plants, talk about the difference if there are differences in materials. Don't just broad brush us this way and assume that because just you said it, we'll buy it. There has to be some demonstration of that.

That can be done today. There is time and if they want to do it or we will do it when we talk about 120 percent power for Units 1, 2 and 3. Again, on the materials the main concern I have is are we talking about the same materials. Are we talking about steel lines, for example, and you just can't say they look the same; therefore, it covers all of them. I want to what the materials are and why certain problems or whatever you show they are applicable to all three.

MS. BROWN: All right. Thank you. The scope of the staff's review includes a vessel surveillance program, the P-T curves, upper shelf energy and reactor coolant boundary materials, programs for protection coatings and flow accelerated corrosion as well as the effects of the uprate on the reactor water clean-up system.

For the reactor vessel and internals, the analysis of record validates the requirements of the ASME code are still met assuming power uprate contentions. The internals were evaluated for any increase in reactor internal pressure differences occurring including a review of the primary and secondary stresses and the loadings which were compared to the base design values to confirm that they remain within acceptable ranges.

The components reviewed specifically are the vessel, the vessel internals including the top guide, core plate, core shroud, and in-core instrumentation. As part of the vessel internals review, staff looked at the following variables and components and programs for acceptability up to 120 percent for the duration of the renewed operating period.

The staff that reviewed the integrated surveillance program found that all the Browns Ferry unit's programs complied with 10 CFR 50 Appendix H and is approved by the staff for the extended period of operation under EPU conditions. This program provides an adequate dosimetry program and includes fracture equivalent evaluations of the weld and base materials that represent the limiting belt line materials of the Browns Ferry units. But implementation at EPU should not result in modifications of the existing surveillance schedule.

In the area of upper shelf energy, Browns Ferry belt line materials did not have initial upper shelf energy values and therefore the Licensee used the approved PWR topical report. This report demonstrated that the belt line materials have enough margin of safety against fracture equivalent to the requirements found in 10 CFR 50 Appendix G. All the belt line materials' upper shelf energy values met the acceptance criteria that is specified in the BWRVIP-74 report. The staff has previously evaluated the upper shelf energy values for the license renewal period assuming extended power uprate conditions which is therefore bound and inapplicable up to 120 percent for the current as well as the extended license periods.

Ganesh, did you want to mention why we felt that this was acceptable for all three units?

CHAIRMAN BONACA: Yes, and for the question I have which is does the topical report BWRVIP-74 applies also to Units 2 and 3 given that the vessels were built in Japan?

MR. CHERUVENKI: Yes, the Applicant did the analysis using BWRVIP-74 upper shelf energy criteria for Unit 1 also and they compiled all the upper shelf energy values. They evaluated (Coughing) topical report, BWRVIP-74 from the external periods of operation like 120 percent EPU which is more bounding. So Unit 1 is automatically covered under that.

MEMBER WALLIS: But the other units have been irradiated for a much longer time.

MR. CHERUVENKI: That's true.

MEMBER WALLIS: Their upper shelf energy has changed. So your conclusions have nothing to do with Units 2 and 3.

MR. CHERUVENKI: We concluded Units 2 and 3 also comply with that.

MEMBER WALLIS: But their shelf energies are quite different.

MR. CHERUVENKI: They're quite different

but they are still bounded by BWRVIP-74 for the external line.

MEMBER WALLIS: Okay. But you cannot make conclusions about them from what you do with Unit 1.

MR. CHERUVENKI: That is true. We did separately all the three units individually.

MEMBER WALLIS: Absolutely.

MEMBER ARMIJO: Maybe you're going to get at these points later, but has there been any inspection of the top guide core plate and core shrouds for Unit 1 taking into account that it's been in wet lay-up for a long time? Are you going to cover that later?

MR. CHERUVENKI: Yes.

MS. BROWN: Let us let the Licensee respond to what inspections they've done on those components.

MR. PHILLIPS: This is Robert Phillips again. We did a complete inspection of the Unit 1 core shroud and all the internals and we did it according to all the VIP requirements and we have those, we submitted those results.

MEMBER ARMIJO: Were there any cracks? This shroud is the old 304, I think. I don't think you replaced it, have you?

MR. PHILLIPS: There was no cracking. Yes sir.

MEMBER ARMIJO: Thank you.

MS. BROWN: All right. The current P-T limit calculations have been previously reviewed and accepted by the staff for all the Browns Ferry units. These curves include the effects of neutron fluence under EPU conditions. Should there be any changes in the fluence values due to core design and surveillance capsule results the P-T curves will be resubmitted for staff review.

The review for irradiated cystic stress corrosion cracking found that the vessel internals are susceptible when they are exposed to a neutron fluence greater than 5 X 10 to the e to 20th. The Licensee has committed to monitor this aging effect by implementing proper chemistry control programs and the BWRVIP which provides frequent inspection guidelines of the reactor vessel internals components. Additionally, the staff found that the Licensee's aging degradation of the vessel internals at uprate found acceptable the Licensee's aging degradation of the vessel internals at uprate conditions.

MEMBER ARMIJO: Could you expand on the chemistry control program, exactly what is going to be done on Unit 1?

MS. BROWN: Robert.

MR. PHILLIPS: Yes. This is Robert Phillips again. TVA has committed to following the VIP requirements for the reactor water chemistry and in addition we're going to implement hydrogen water chemistry and we're also looking into when to apply noble metals chemistry.

MEMBER ARMIJO: So that on the restart, you will not use noble metal application on the restart or at the end of that first cycle.

MR. PHILLIPS: Do you want to go ahead and answer that?

MR. CROUCH: The noble metals you have to have a certain amount of operating time before you can apply it and then you have to have been operating and let the vessel, you have to hold it 275 degrees and -- It's not something we can do at restart.

MEMBER ARMIJO: I understand.

MR. CROUCH: We'll have to start up and then come back and do it.

MEMBER ARMIJO: I'm just trying to find out if you plan to add noble metals during the first cycle at the appropriate time.

MR. CROUCH: Yes.

MEMBER ARMIJO: Okay. That's all I have.

MS. BROWN: The staff's review focused on compliance with the reactor pressure vessel internals with these acceptance criteria as listed: 10 CFR 50.60 Appendix H, Appendix G as well as the guidance provided in the staff's review standard RS-001.

As a result of the staff's review, staff has determined that under power uprate conditions adequate safety margins will be maintained for the vessel surveillance program, upper shelf energy assessment, the pressure/temperature limits and the structure integrity for the vessel and the internals. As discussed previously, those conclusions are valid for all Browns Ferry units up to 120 percent for the current and extended license renewal.

MEMBER WALLIS: Could you explain to me the state of this vessel all this time when nothing was happening there? Was it fully dry or was it wet or where was it wet?

MS. BROWN: Robert.

MR. PHILLIPS: Go ahead, Bill.

MR. CROUCH: It was wet. Full wet lay-up of the vessel and the recirc piping.

MEMBER WALLIS: Say that again.

MR. CROUCH: The vessel was fully wet.

MEMBER WALLIS: It was fully of water all this time.

MR. CROUCH: Yes, being maintained with chemical controls and the recirc system was wet, but that's since been replaced. The RWCU system was wet.

MEMBER WALLIS: All this for many years? It was just sitting there wet?

MR. CROUCH: It was sitting there wet, yes --

MEMBER WALLIS: And how about the containment? What was the containment doing? It was completely dried out or what?

MR. CROUCH: No, there was -- The drywell was obviously dry. The suppression pool had water in it.

MEMBER WALLIS: Full of water. That was full of water, too.

MR. CROUCH: Yes. And it has since been drained. All the protective coating has been reapplied or repaired and filled back up with water.

MS. BROWN: All right. We're going to proceed into reactor coolant pressure boundaries materials. The reactor coolant pressure boundary consists of those systems containing high pressure fluid. The review indicates that the uprate results and no significant increase in flow, pressure, temperature or mechanical loading and a slight increase in oxygen generation rate.

MEMBER WALLIS: No significant increase in water flow?

MS. BROWN: No significant.

MEMBER WALLIS: In water flow? When you say flow, you mean water flow through the circulation pumps. You don't mean steam flow.

(Off the record discussion.)

PARTICIPANT: Steam flow is going up.

MEMBER WALLIS: No, you certainly don't mean steam flow. You mean water flow.

MS. BROWN: Yes sir.

MEMBER WALLIS: Through the core is what you're talking about. But the steam flow does change.

MS. BROWN: Yes.

MEMBER WALLIS: And that makes no difference?

MR. GEORGIEV: That is out of the scope of what we're talking about.

MEMBER WALLIS: Out of your scope, I see.

MS. BROWN: Yes, we're just talking about the reactor coolant.

MR. GEORGIEV: We're talking about the

reactor coolant pressure bounding materials, basically the recirc line and core spray, clean-up water.

MEMBER WALLIS: Why would flow affect the pressure boundary? Because of corrosion effects or something or what?

MR. GEORGIEV: Because if you have a temperature change, you do have increase in oxygen count and if you have increase in oxygen count, then you do increase the propensity for stress corrosion cracking and that is why we are very thorough in that review because there will be a lot more inquiring about why should we accept that nothing will change.

MEMBER BANERJEE: Well, the pressure increases. Right?

MR. GEORGIEV: Not significantly.

MEMBER SIEBER: Thirty pounds.

MEMBER ARMIJO: Anyway to make up for pressure drop if I understood it correctly.

MEMBER BANERJEE: How much of a temperature change is there?

MS. BROWN: He asked for the temperature change.

MR. CROUCH: Previously slide. Hang on one second and I have that from our slide from yesterday.

MEMBER SIEBER: A few degrees.

(Off the record discussion.

MR. CROUCH: The positive dome pressure went up to 30 psi. The dome temperature went up four degrees. The feedwater, the core inlet enthalpy went up 3 BTUs per pound mass. That would be about a three degree temperature change in the bottom head.

MEMBER BANERJEE: And these temperature changes don't affect anything?

MR. GEORGIEV: No, they don't.

MS. BROWN: Not significantly.

PARTICIPANT: Pretty small.

MEMBER WALLIS: We are talking about the reactor coolant pressure boundary and this is a boiling water reactor. So the main steam line or the steam line that comes out of the top is a pressure pound rate, isn't it?

PARTICIPANT: Right.

MR. GEORGIEV: But it's not --

MEMBER WALLIS: Now the flow rates in the steam, the changes in the steam, affect parts of this boundary. There is a significant change in flow.

MR. GEORGIEV: That's not what the review is.

MEMBER WALLIS: Why not? It's part of the boundary.

MR. GEORGIEV: It has been reviewed but on a different area.

MEMBER WALLIS: On a different area. So when you make these sweeping statements about no change in flow, you're talking about only the water on not the --

MR. GEORGIEV: The reactor -- That's right.

MEMBER WALLIS: But there's a pressure boundary around the steam region, too. Right?

CHAIRMAN BONACA: We'll talk about that.

MEMBER WALLIS: Somebody else is going to talk about that?

CHAIRMAN BONACA: The lines.

MEMBER WALLIS: Someone is going to talk about steam lines and the dome and everything.

MEMBER CORRADINI: Later. If you're thinking about the effects on mechanics and steam dryers I think that's the next couple of topics.

MEMBER WALLIS: I don't know. I just right now see this sweeping thing about pressure boundary. I assume that anything that's a pressure boundary matters, but apparently not for your presentation. Right? We're going to hear about that sometime.

CHAIRMAN BONACA: We'll have to.

MS. BROWN: Yes sir.

MEMBER WALLIS: Okay. That's when -- When is that?

MS. BROWN: I believe that's in the mechanics discussion Mr. Wu and Mr. Scarbrough.

CHAIRMAN BONACA: Now when you talk about for example pressure increase 30 psi that's for the 105, not for the 120. Right?

MS. BROWN: Originally the request for 30 psi did come in the Unit 120 percent.\

CHAIRMAN BONACA: Yes, because I mean you had to go to --

MS. BROWN: But the Licensee indicate that they did meet it for the 105. So that review was included in the Unit 1 105 SE.

CHAIRMAN BONACA: But for Units 2 and 3 for example?

MS. BROWN: It was already approved for their 105.

CHAIRMAN BONACA: So therefore in the case of the constant pressure power uprate.

MS. BROWN: It's consistent with the constant pressure power uprate, but I believe the

Licensee wanted to license in the same way and do the review the same way. So they did it under --

MEMBER WALLIS: Now how about the feedwater? You're making more steam. So presumably you have to put in more water.

MS. BROWN: Yes sir.

MEMBER WALLIS: This is also a coolant pressure boundary?

MR. GEORGIEV: Well, that's another area all together.

MEMBER WALLIS: So what are you talking about?

MR. GEORGIEV: I'm talking about the recirc line.

MEMBER WALLIS: You're not talking about the reactor coolant pressure boundary then. You're talking about only specific things.

MR. GEORGIEV: That's right.

MEMBER WALLIS: What about the feedwater? There's a higher flow rate in the feedwater. What does this do? What does the higher flow rate in the feedwater do? It has some effect. Right?

MS. BROWN: Yes sir. It does.

MEMBER WALLIS: Does it change the corrosion or the wear or whatever, erosion or --

CHAIRMAN BONACA: I would expect that to be less than the flow oxide the corrosion on the steam lines for example. Right?

MS. BROWN: Yes sir.

CHAIRMAN BONACA: So you will talk about steam lines.

MEMBER WALLIS: Someone will talk about those things?

MS. BROWN: Yes sir. We're going to talk about --

MEMBER WALLIS: I'm talking about all the things which have no significant change is irrelevant. What we want to know what's changed and what matters.

MS. BROWN: Yes sir.

MEMBER WALLIS: Well, could you talk about those things or would someone focus on those things?

MS. BROWN: Yes sir.

CHAIRMAN BONACA: Yes, yesterday we heard about the changes they made to the feedwater system to provide --

MEMBER WALLIS: You heard about that yesterday.

MS. BROWN: Yes sir.

CHAIRMAN BONACA: Yes, but not necessarily to the materials.

MS. BROWN: That's true.

CHAIRMAN BONACA: We talked about the functionality of the system, I mean, the -- pumps --

MEMBER WALLIS: There is an increase in FAC. Is there an increase in flow cystic corrosion?

CHAIRMAN BONACA: Yes.

MS. BROWN: If you give us a second. Why don't we try to step through a little bit and we'll get to the area on FAC.

CHAIRMAN BONACA: Okay.

MS. BROWN: And then we can get to your questions then. All right?

CHAIRMAN BONACA: Thank you.

MEMBER CORRADINI: I don't mean to slow you down after you're just trying to speed up.

MS. BROWN: That's okay.

MEMBER CORRADINI: But you made a comment about oxygen content and it's not my area, but I want to at least understand. So the previous slide talked oxygen concentration. Are you running essentially the same chemistry and from practical experience, that's no big deal when I change power levels. Do you see my question?

MS. BROWN: I have to defer to the Licensee.

MEMBER CORRADINI: Because what little I understand about this, the oxygen chemistry, the oxygen content is quite important relative to corrosion chemistry if I understand it correctly. So can you kind of address that just briefly?

MR. PHILLIPS: Yes sir. I just need to make sure I understand your question.

MEMBER CORRADINI: I'm just trying to understand if the procedures you use -- Let me just restate it because again it's a somewhat of an uninformed question. Is the procedures you're using relative to oxygen control identical independent of power so that it's not a flow issue? It's strictly a chemistry in the coolant. In other words, if I change the flow by 20 percent, I don't need to change the chemistry control. That's another way of asking the question.

MR. PHILLIPS: I'm --

MEMBER CORRADINI: Let me try again.

MR. PHILLIPS: Yes sir.

MEMBER CORRADINI: Because again, I'm not completely -- If I understand it, let's just pick something that you're running it so many parts per billion oxygen content.

MR. PHILLIPS: Right. Yes sir.

MEMBER CORRADINI: Now I change the power by 20 percent. I change the flow by 20 percent. I assume therefore the corrosion is not a liquid phase control phenomenon. It's totally solid phase. So regardless of the flow rate, I keep the chemistry identically the same within the coolant and how it affects corrosion. That's what I'm kind of asking.

MR. PHILLIPS: Yes, we would still have the same limits and I guess the best way to respond to your question is that in this particular case the actual oxygen, that would be factored into our flow accelerated corrosion control program and we've gone through that evaluation and we hadn't seen any effects or significant effects. Let's put it that way.

MEMBER CORRADINI: Okay. So one last one. So my interpretation of that is that on the liquid side, I view this is a very simplified manner. I apologize if I'm too slow on this.

MR. PHILLIPS: No.

MEMBER CORRADINI: It's that I essentially have corrosion effects that are liquid phase controlled at this interface and solid phase control so that if I change the concentration, if I have a change in flow, I could potentially affect the rate of corrosion.

MR. PHILLIPS: Yes.

MEMBER CORRADINI: Unless it's totally dominated by the solid phase phenomena.

MR. PHILLIPS: No, what you said is correct, but the -- Bill, where are those?

MEMBER CORRADINI: So I'm kind of curious what you change when you change power relative to chemistry control or if the answer is you don't change anything.

MR. PHILLIPS: No, the chemistry controls would be the same. The mass flow would change. It would slightly increase and that was presented yesterday.

MEMBER CORRADINI: Sure. I understand that.

MEMBER SIEBER: When you increase power, do you not increase the rate --

MR. PHILLIPS: The mass flow rate. That's some feedwater recirc where those limits --

MEMBER SIEBER: You're generating more oxygen by radiolytic decomposition --

MEMBER CORRADINI: So I'm curious what they change relative to chemistry control along with that.

MEMBER ARMIJO: I think, Mike, that's why this hydrogen addition in noble metals is just to overwhelm those small changes.

MEMBER SIEBER: Right. It's the hydrogen injection that does it.

MEMBER ARMIJO: Both for IGSCC and maybe even have a benefit of flow accelerator corrosion.

MEMBER BANERJEE: You have to inject more hydrogen.

MEMBER ARMIJO: In principle, you should, yes.

MEMBER SIEBER: Yes.

MR. PHILLIPS: Maybe we should just get back to them on that one. I don't want to answer that.

MEMBER ARMIJO: It may be a small difference but it's --

MEMBER BANERJEE: What you change, yes.

MEMBER SIEBER: You will consume more hydrogen, too.

MEMBER ARMIJO: Right.

MEMBER SIEBER: It's just not a higher content. There will be a consumption change.

MEMBER BANERJEE: Do you increase hydrogen injection?

MR. DeLONG: This is Rich DeLong. I'm the

Site Engineering Manager at Browns Ferry. There's essentially no difference in control here with noble metals and low hydrogen injection which is what we do now. That same mix will continue noble metals coating with low hydrogen injection and we monitor dissolved oxygen. We monitor what our constituents are, our hydrogen concentration and feedwater, which tell us what concentrations go into the vessel to support oxygen scavaging as well as to keep the ECPs, the electro-chemical potentials, where it needs to be for all the vessel internals.

MEMBER ARMIJO: Are you monitoring ECP on all three units?

MR. DeLONG: We don't have ECP monitors at Browns Ferry if that's what you mean.

MEMBER ARMIJO: You don't?

MR. DeLONG: Our ECP monitoring is based on those parameters, those chemistry parameters, as they are fed into the approved ECP model.

MEMBER ARMIJO: Okay. So you don't have actual instrumentation.

MR. DeLONG: Not at Browns Ferry. No, we don't.

MEMBER CORRADINI: So you monitor a series of variables and then go through some calculation that gives you an approximation of where you are relative to the chemical potential.

MR. DeLONG: That's correct.

MEMBER CORRADINI: And you did -- If I might just, again just for learning purposes here, I apologize, so that you add on a continuing basis and monitor oxygen level and you said something else. I apologize. You said?

MR. DeLONG: We monitor the concentration of hydrogen in feedwater also.

MEMBER CORRADINI: Okay.

MR. DeLONG: You're injecting into feedwater. So you monitor, periodically monitor, what that concentration is.

MEMBER BANERJEE: But you do have any measure of the hydrogen within the vessel itself.

MEMBER SIEBER: No.

MR. DeLONG: Not directly, no.

MEMBER BANERJEE: Not directly.

MR. DeLONG: No.

MEMBER BANERJEE: So whether it mixes or whatever happens.

MR. DeLONG: We actually, the monitoring capability for us is the concentration and where we measure the concentration in the feedwater supply to the vessel.

MEMBER CORRADINI: Thank you.

MEMBER WALLIS: The core spray flow rates are the same?

MS. BROWN: Yes sir. So for on Unit 1, the Licensee is replacing the reactor recirc system piping with corrosion resistant material which is resistant to IGSCC. The replacement piping used is an improved design which eliminates several piping welds. As a result, all the recirc welds are Category A in accordance with NUREG 013 Rev. 2.

The Licensee also replaced the residual heat removal, reactor water cleanup and jet pump safe ends with tight 316 NG materials as Mr. Georgiev had said previously while the --

MEMBER WALLIS: Now this plant has been rebuilt. A lot of piping has been replaced?

MS. BROWN: Yes sir.

MEMBER WALLIS: Being replaced with exactly the same size as it was before? I mean there's been no effort made to say reduce the resistance of the lines through which pumps pump so that they won't -- or the suction lines so that there won't be such a problem with NPS 8. So blindly replaced them by the same thing that was there before without any improvement? Is that what's happened?

MR. CROUCH: The lines that were being replaced were the discharge lines.

MEMBER WALLIS: But you haven't replaced anything with a view to improving things? Made pipes bigger or anything like that?

MR. CROUCH: Not on the suction side.

MEMBER WALLIS: They're all the same as they originally were?

MR. CROUCH: All the suction piping is the same as it originally was. Nothing was replaced.

MEMBER WALLIS: Because there seems to be an opportunity in this plant to think about how to improve. You're going to replace the pipe, how to make it better. That didn't happen. They went back to the original design. Maybe the materials changed?

MR. CROUCH: No. On the suction piping, nothing was changed. Nothing was replaced.

MEMBER WALLIS: Nothing was replaced, but there was an opportunity to replace it?

CHAIRMAN BONACA: But I think it was an attempt to have identical units, the three.

MEMBER WALLIS: Identical units. Okay.

CHAIRMAN BONACA: Now the question I have is when you say replace the material with corrosion resistant material, are these changes identical for Units 2 and 3?

MR. CROUCH: Yes.

CHAIRMAN BONACA: Because if I remember from license renewal, the experience you had for Units 2 and 3 was applied to Unit 1.

MR. CROUCH: Correct. The same materials were used on Unit 1. In some places, we did more of the piping. For example, in the recirc system, we replaced more of the piping but it was with the same material.

CHAIRMAN BONACA: Okay. Because I mean if you want credit for Units 2 and 3, that's what we need to hear. I wasn't saying that you should go there, but I'm saying that's the kind of information we need that you did the same changes they did that were already implemented in Units 2 and 3. Okay.

MEMBER ARMIJO: Was there any area in the recirc system where you retained the old 304 stainless steel material?

MR. CROUCH: Not in Unit 1.

MEMBER ARMIJO: Okay. So there is something in the other units.

MR. CROUCH: Yes, the other units, the large suction and discharge piping was retained.

MEMBER ARMIJO: Okay. So as far as the corrosion resistant stainless steels, Unit 1 has replaced more with that material?

MR. CROUCH: That is correct.

MEMBER WALLIS: You did improve something. You improved the strainers. The strainers are a new design.

MR. CROUCH: The strainers are -- Are you talking about the ECCS suction strainers? They are the same design as what's in Units 2 and 3.

MEMBER WALLIS: But they are an improvement over the original.

MR. CROUCH: Yes. They are the large stack GE disk strainers.

MEMBER BANERJEE: And tell us about the vortexing. We're still waiting to hear. I think that was tabled yesterday.

MR. CROUCH: Yes, we're still looking at that.

MEMBER ARMIJO: The last question I had on this was the core spray lines, were they replaced with 316?

MR. CROUCH: No, they were replaced with 333 carbon steel.

MEMBER ARMIJO: Okay.

MS. BROWN: That was the last thing I was going to say on this slide.

CHAIRMAN BONACA: Okay. Let's --

MS. BROWN: Excellent. The staff found that TVA's programs designed to mitigate IGSCC in Units 2 and 3 had been reviewed and found acceptable by the staff and that the reactor coolant pressure bounding materials continue to meet 10 CFR 50.55(a), Part 50 Appendix A, and Appendix G and as we just stated before, as Unit 1's programs are the same as Units 2 and 3, we find it acceptable at 120 percent condition as well which bounds to operation of Unit 1 at 105 percent.

Were there any other questions on reactor coolant pressure boundary before we move onto protective coatings?

(Off the record discussion.)

MS. BROWN: Protective coatings. Excellent. The NRC staff's review focused on the suitability and stability of containment code instrument design basis loss of coolant accident considering the radiation and chemical effects.

MEMBER WALLIS: Did you talk about the effects of coatings on MPSH yesterday?

MEMBER CORRADINI: We had fun with that.

MEMBER BANERJEE: Indirectly. We haven't --

MS. BROWN: We're going to touch on it right now.

MEMBER WALLIS: I guess we can revisit it. I was surprised. There was a statement in the SER that the staff found that protective coating debris will not hinder MPSH, but there was no sort of evidence cited or anything like that. It was just a statement.

MR. YODER: Matt Yoder from NRR staff. I think that the point being made in the SER or at least what was trying to come across is there is no increase in the effect that coatings will have on MPSH, meaning they're already accounting for the coatings debris prior to power uprate conditions impacting MPSH. The power uprate does not increase the amount of coatings debris or the change in MPSH.

MEMBER WALLIS: I was a little curious about how anybody knew how to do this. I mean how anybody knew how to predict the effect of coatings on MPSH. Is this a science that's mature?

MR. YODER: Well, I think we're learning a lot in GSI-191 space and we may come to a point where we take another look at how these things were handled --

MEMBER WALLIS: So this will be taken care through the 191.

MR. YODER: The way that the staff has agreed to take care of this situation is we will keep the BWRs in the manner that they resolved the strainer replacement. Lessons learned in GSI-191 will then potentially be applied back to the BWR as a whole.

MEMBER WALLIS: So there might be a message for BWRs. We don't know yet.

MR. YODER: Correct.

MEMBER WALLIS: Thank you.

MEMBER BANERJEE: I guess you can tell us if the coatings are going to be resistant in this case.

MR. YODER: This review focuses on under accident conditions under an uprate type situation. Are these coatings still going to remain qualified? Are they going to remain in place and not become an additional debris source?

MEMBER BANERJEE: Is all the coating qualified?

MR. YODER: No. There are unqualified coatings and those are accounted for in the head loss calculations. So they maintain a log of how much unqualified coating debris. We're accounting for it in our debris transport and head loss analysis.

MEMBER BANERJEE: How much is qualified and how much is not in terms of mass?

MR. CROUCH: Eva. Can we --

MS. BROWN: Yes, Bill. I'm sorry.

MR. CROUCH: Obviously, the bulk majority of all the coatings are qualified. We have an administrative limit that we maintain of only 157 square feet of unqualified coating.

MEMBER BANERJEE: And what does that translate to in terms of mass?

MEMBER WALLIS: Very small fraction, isn't it?

MR. CROUCH: In terms of overall coatings? It's very, very small. It would much, much less than 1/10 of a percent.

MR. YODER: You're talking about coatings in the containment probably let's say about 200,000 square feet. So if only 157 square feet of that is not qualified, it's a very small amount.

(Off the record discussion.)

MEMBER BANERJEE: Well, I'm more interested in knowing how much blockage that 157 square feet can do, I mean, if it got to the strainer.

MEMBER WALLIS: Well, if it's uniformly distributed, 157 square feet.

MEMBER BANERJEE: If it's uniformly distributed, right.

CHAIRMAN BONACA: But you said that it's been accounted for.

MR. YODER: This was all considered when the strainers were replaced in the boiler water reactor.

(Off the record discussion.)

MEMBER WALLIS: Right.

MR. YODER: I think what you find and what we find when we're looking at GSI-191 of the BWRs, it's not going to be a straight this many square feet of coating. It's just this much head loss. You have to account for all the other debris, the fibrous debris. It's an additive effect of all these things.

CHAIRMAN BONACA: Sure.

MR. YODER: So it's not a straightforward I have 100 square feet of unqualified coatings and that's going to give me X amount of head loss. Right.

CHAIRMAN BONACA: But would the qualified coating not provide any contribution to the blockage?

MR. YODER: You will have some qualified coatings that are going to come off right by the pipe break locations, say, in LOCA. Those are going to get blasted off and that amount of coatings is accounted for in that calculation.

(Off the record discussion.)

MR. YODER: Also you'll have some areas where you have degraded of those coatings either by mechanical damage, you know, something slammed into the wall, a blister from heat damage, etc. and those will be added into that unqualified coating log, that administrative 157 square feet.

MEMBER BANERJEE: Yesterday they said that there was no or very little fibrous or particulate material in the insulation. Is that what you found as well?

PARTICIPANT: (Off the microphone.) It's not what we said.

MR. YODER: Staff did not get into that level. This review was focused on is there going to be an additional debris term from coatings as a result of power uprate. Now when the review was performed when those modifications were made, that was included in that review.

MEMBER BANERJEE: So you don't know the answer.

MR. YODER: Well, I did not perform the

review when it was done originally.

(Off the record discussion.)

MEMBER BANERJEE: We still may want to find out.

MR. CROUCH: Eva.

MS. BROWN: Yes sir.

MR. CROUCH: Let me address this. I don't think we said yesterday but let me clarify this. There is some fibrous material inside the containments. It's back inside the piping penetrations. There are 11 piping penetrations that have fibrous material back in them and that is included into the strainer calculations. The only way that fibrous material would get out would be if the pipe actually broke inside the penetration and blew it out. But it isn't considered.

MEMBER BANERJEE: Did the staff look at where there was fibrous material, particulate material, and what potential it might have on the strainer blockage?

MR. YODER: Not as part of this power uprate review. Those were all things that were considered in the analysis when the strainers were resized.

MEMBER BANERJEE: When was that?

MR. CROUCH: In 1998.

MS. BROWN: The late 90's. There's a staff safety evaluation for the suction strainers for those.

MEMBER BANERJEE: So we are depending on 1998 evaluation today for the behavior of the suction strainers.

MR. YODER: Yes, and as I said, we are learning things in GSI-191 when we're looking at the PWRs that may not have been fully considered when those strainers were resized and the staff will make a decision based on the outcome of all the testing and work that's going on for the pressurized water reactors as to whether some of those things need to be looked at again.

MEMBER BANERJEE: Where is that on your parts? I mean when are you going to look at that?

MR. YODER: I don't think I'm the right person to address that at this time.

MEMBER BANERJEE: You have nothing to do with the strainers. You're strictly -- Your commission is only to look at the coatings at the moment. That's all.

MR. YODER: In this capacity, yes.

MEMBER BANERJEE: Who is going to look at strainers?

MR. YODER: As I said, as part of this review, those will not be addressed. We will -- I think there's a reviewer that's addressing the pumps and the suction head available, etc.

MS. BROWN: That was yesterday with Mr. Lobel. We did container accident pressure --

MEMBER BANERJEE: But you just gave us a very broad brush treatment. Nobody addressed the strainers in particular. Right?

MS. BROWN: Yes, because that review was conducted in another safety evaluation. The staff relied on a previous --

MEMBER WALLIS: I found it impossible in the literature I looked at to see what the evidence was for how the strainers had been considered and I wasn't able to ask questions yesterday. I didn't get any answer, but I looked through the stuff that came to us and I couldn't find any evidence about how the strainers were analyzed.

MEMBER KRESS: There was a generic resolution of this issue for BWRs.

MEMBER WALLIS: It wasn't clear. I mean it talked about -- In PSH, there was no evidence that said that the strainers -- The strainers seem to contribute nothing as far as I can make out. There was evidence for that.

CHAIRMAN BONACA: The point they've made is that the power uprate would not cause an increase in the loading of the strainers.

MEMBER WALLIS: No change.

CHAIRMAN BONACA: No change.

MR. YODER: That's correct. So debris that's generated from the break location, the insulation, coatings, what have you, latent debris, is going to be the same after uprate conditions as it was in the previous analysis.

MEMBER WALLIS: But the effect of that on MPSH is different for the uprate because it now becomes critical. If there had been a higher pressure drop across the strainer, a high pressure drop, then it would have had an influence on the MPSH.

MR. YODER: If you have an increase in flow across that strainer --

MEMBER WALLIS: No, it's even the same --

MR. YODER: -- then the same amount of debris could give you a higher --

MEMBER WALLIS: Well, if a higher temperature in the pool, the pressure drop is more significant.

MEMBER BANERJEE: See what's happening is there's a requirement for containment over pressure credit here. So here it becomes more critical to understand how much pressure drop there is in this part of that which is the strainers. So it becomes important to revisit this and make sure that it's all okay. As far as I'm concerned, it's quite critical. If you're saying it's only half of psi instead of 4 psi or 4 psi instead of 8 psi, it makes a big difference the suction head requirement.

CHAIRMAN BONACA: I think calculations were done by TVA.

MEMBER BANERJEE: Were they done in 1998 the last time?

CHAIRMAN BONACA: No, but they did calculations now to look at the pressure drops of MPSH.

MEMBER BANERJEE: I guess we're asking if the staff has reviewed those.

CHAIRMAN BONACA: That's right and we would like to know how they were accounted for in the calculations actually.

MR. WOLCOTT: J.D. Wolcott, TVA. Our strainer blockage accounting for different debris did not change with power uprates. So the basic debris combinations and how they block the strainers is the same now that we used that was determined and looked at in 1998 because the flow didn't change and the debris mix didn't change.

You were asking whether or not it got looked at part of power uprate in the materials that you have. Mr. Lobel did ask a question in RAI and asked us to go back over how debris was done and that's in our RAI response of 3/7/2006. There's a pretty succinct rundown of what type of debris there is and how it's put on the strainers if you want to look at that.

MEMBER WALLIS: This is a problem in our review. We get a CD and open up a window and you get sort of 25, 40 documents which replies to RAIs. There's no indication of which one you need to pick out to get the strainer issue and there was no way I can read all the documents in order to find the one I want.

MS. BROWN: There was actually --

MEMBER WALLIS: So I have a real problem in this review.

MS. BROWN: Mr. Wallis, actually we had that same issue going to the 105 and TVA provided a crosswalk on September 22, 2006 that referenced each question and the subject area back to the RAI. So maybe that would --

MEMBER WALLIS: You have this available?

MS. BROWN: That was part of the submittal that you received, the September 22nd --

MEMBER WALLIS: I don't know where I'd find that.

MEMBER BANERJEE: There is a crosswalk.

MEMBER WALLIS: There is somewhere?

MS. BROWN: Yes sir. Yes, it was in back.

MEMBER BANERJEE: Hard to find it.

MEMBER WALLIS: Okay.

MEMBER BANERJEE: It would be useful to have a search engine. Maybe I'll do one to find by keyword or something. No, but going back to this, for the power uprate you're going to put more energy into the containment. Won't that have an effect on the pregeneration if you increase your energy input by 20 percent? Do you think that you should get more debris?

MR. YODER: If you want to talk specifically about the coatings?

MEMBER BANERJEE: Yes.

MR. YODER: These coatings, just to touch on how these things are qualified, you have a steel coupon or a concrete coupon depending on what substrate you're dealing with. You apply this coating as it would be applied in the plant. You irradiate it, put it in autoclave, subject it to a simulated DBA, temperature, pressure, spray environment to show that it will remain adhered under those conditions.

Now that temperature and pressure curve is bounding of what you would see under postulated accident at the uprate conditions. So you would not expect any more coatings to fail and that under the uprated accident scenario as opposed to the 100 percent power scenario.

MEMBER BANERJEE: So when you're saying "uprated" this is 120 or 105?

MR. YODER: In either case. That curve that was time/temperature/pressure curve that was used to qualify these coatings originally still bounds all the way up to 120 percent operation.

MEMBER POWERS: I guess I've always been curious on that testing of qualified coatings. Is not the de-adherence of a coating intimately associated with its internal oxidation?

MR. YODER: That is one of the issues that is currently being looked at in the GSI-191. As you know we're doing a lot of work with coatings, doing influence debris characteristics, transport, caging, degradation of coatings and one of the things that is being looked at and there's an EPRI study underway is is there a radio-oxidation effect long term with a low dose that causes the degradation of these coatings and I don't think it's fully understood because we kind of have a unique situation in a containment that you don't see in the automotive industry or in a bridge. You know, other areas where you have a lot of information and a lot of operating experience with coatings. So as I said, that's a study that's underway now being conducted by EPRI.

MEMBER POWERS: Yes. I guess that's curious to me. I would think that those data would be directly applicable since the radiation source in this case is ultraviolet radiation instead of gamma radiation and I would think that would be bounding because the cross section for ultraviolet absorption is high, whereas the cross section for gamma absorption is low. So that would be a more bounding case, wouldn't it?

MR. YODER: I don't claim to be an expert in this area, but as I said, these are all the questions that are being raised in the studies that are underway as we speak.

MS. BROWN: All right.

MEMBER POWERS: Are these -- Well, fair enough. You've given me my answer.

MS. BROWN: I think that Matt has gone over most of this, but let's touch on it just a little bit when we talk about the coatings and qualifications on Unit 1. For the uprate, the Licensee indicated that the increase in temperature and pressure of the reactor coolant system has no impact on the zone of influence associated with the assumed pipe diameters and that the previous testing remained bounding at peak accident conditions at all service level one coatings with one exception. This one coating system configuration had not been previously tested by the Licensee and the Licensee stated that they would not use it in containment.

When we look at Units 2 and 3, as we already discussed, the Licensee's designs assumptions regarding debris generated and transported in order to size, the ECCS section strainers was unaffected. Therefore the debris loading was the same as the pre-EPU calculations.

MEMBER BANERJEE: So I asked the question about what the basis for this might be if you have more energy put into the containment. So can you give me an answer as to why you think it should be unaffected in spite of the higher deposition of energy during the --

MR. WOLCOTT: J.D. Wolcott, TVA. I'll try to answer that. The way we're doing it is derived from the BWR ERG methodology in terms of how to determine debris generator and there are two components of coating debris involved. One of them is generated from the blast field of the break location and that assumes that everything in that field is blown off. In our particular case, that's 741 square feet or 85 pounds.

Then it's also assumed that all of the unqualified coating comes off irrespective of whether it's in the blast field or not and that's 157 square feet maximum. That's how much we allow with our coatings log that the staff just talked about. The coatings that come off in the blast field, that's driven by the field of the blast and the maximum jet that we can generate and that driven by reactor pressure fluid enthalpy, not necessarily the extra energy that comes from 120 percent power. A 120 power generates more decay heat which certainly heats up the pool a lot more particularly as time goes along. But we don't feel like the energy that would be available to blast something off would change significantly with uprate.

MEMBER BANERJEE: So if we had the same pressure and had a plant running at 50 percent, we'd get the same amount of debris?

(Off the record discussion.)

MR. WOLCOTT: Yes.

MEMBER BANERJEE: Independent of the power. What about two percent?

MR. WOLCOTT: I don't think it would matter. I think if we have a pressurized vessel full of saturated water and you let it go you're going to get the same steam cleaning.

CHAIRMAN BONACA: I guess the point is that the zone of influence is not impacted and anything in the zone of influence is removed before the uprate or after the uprate. That's what you --

MR. WOLCOTT: The zone of influence stays the same and it's assumed that everything in the zone of influence comes off.

CHAIRMAN BONACA: Comes off.

MEMBER BANERJEE: So the number of fuel power seconds being held in the fuel is irrelevant. Is there any proof of that?

MR. WOLCOTT: No, I think --

MEMBER BANERJEE: Because that comes out pretty fast.

MR. WOLCOTT: That would be an engineering judgment.

MEMBER BANERJEE: In your judgment, the number of full power seconds held in the fuel is irrelevant.

MR. WOLCOTT: To this particular issue, yes. To the energy available and the zone of influence to get the coatings off in the zone of influence.

MR. CROUCH: Recognize that there is a conservativism in this calculation that it's assumed that 100 percent of the coatings within the zone of influence comes off and doesn't account for the fact that there's some -- You probably can't blast the coatings off the backside of pipes and things like that. So it has conservativisms built in it that would more than outweigh the small increases in energy from -- just due to the 30 psi increase.

MR. BRYAN: This is Bob Bryan. The way you do the jet calculations, we essentially assume that the pipe instantaneously ruptures and so what you see is you see the depressurization wave and you're talking literally fractions of a millisecond and the zone of influence is sized based on that initial energy release.

As in a large break LOCA, the reactor vessel depressurizes very rapidly and so two or three seconds into the event the flow rate out of the break is substantially lower than it was in the first half of a second. So since we sized the zone of destruction on this maximum area based on the initial energy release, stored energy in the fuel doesn't make any difference. It's all what comes out right there in the first 20 milliseconds.

MEMBER BANERJEE: I'll look into it. Thanks.

MEMBER POWERS: He wouldn't care if there was no fuel at all in there.

MEMBER BANERJEE: Yes. It's just a big vessel.

MEMBER POWERS: Yes, a big pressurized vessel and there would be the same as --

MR. CROUCH: It's the vessel temperature and pressure is what drives the response.

MEMBER POWERS: Anything that happens later in time is so weak it doesn't affect things.

MR. CROUCH: Right.

MEMBER KRESS: The only effect to the

energy is to increase the time in which the blowdown occurs but you've already assumed everything is going anyway.

MR. BRYAN: That's correct. I mean at the tail end of the thing you get some long term effects like on coatings you have to look at to make sure your qualified lives are good for what the temperature looks like three hours out or something like that. But that's an appreciable -- That's not going to change appreciably what the debris loading is. All of the insulation, all of the early coatings, you know, those are what loads your strainer up early on.

The other thing that happens is as you get out in time the flow demands on your strainers go down. So what you're interested in is what the debris loading is when you're at the highest flow rates through the strainers.

MEMBER ARMIJO: On your slide 17, you tell us that the coatings are subject to increased temperature, pressure and radiation during operation and so you must assume that their properties or adherence is not affected.

MR. YODER: This goes back to the qualification testing we were talking about and what we're talking about here is under accident conditions, you would see that it's going to be subjected to increased pressure, temperature and radiation fields and as I said, the testing that was done on these coatings before they were installed in the plant bound these increased temperature, pressure and radiation conditions.

MEMBER ARMIJO: Okay. So they've been tested -- they've been qualified for those.

MR. YODER: They've been qualified beyond what they would experience in a postulated accident scenario.

MEMBER ARMIJO: It would be nice to put that in the chart because it just raises questions otherwise.

MEMBER SIEBER: Those increases don't amount to much.

MEMBER ARMIJO: Yes. I think they're small but the more important thing is the qualified coatings have been qualified beyond these --

MEMBER SIEBER: They have to just to get margin.

MEMBER ARMIJO: Yes.

MS. BROWN: Bill, did you have a --

MR. CROUCH: Just if you look at page 20, that conclusion is on there.

MS. BROWN: Yes, I was going to -- Thanks. All right. I think we've already talked about the coatings.

Nineteen. These are just the acceptance criteria the staff used as part of their review and if we go to the outcome, except for Unit 1, the staff found that the qualification testing was satisfactorily performed assuming 120 percent. For the design basis LOCA, the evaluation assumes any previously identified, unqualified coatings are assumed to fail under accident conditions and are accountable for in the sump blockage -- For Units 2 and 3, the review found that the original analysis conclusions remain bounding. Therefore, the staff found that the protective coatings remain acceptable for uprate for all units up to 120 percent.

Do we have anything else we want to discuss before we go onto low accelerated corrosion?

MEMBER ABDEL-KHALIK: Well, I guess it was stated that the blast field area was 741 square feet. The question is how was that estimated.

MR. YODER: I don't have all the history here but if you go back to the work that was done '98 to resize the strainers, basically what they did is they took a cone from the break location. I believe it was 10.5 degrees from center line, projected that onto a wall a certain distance away and used that surface area of that wall as a bounding amount of coating debris that you would expect to get from a pipe break.

MEMBER ABDEL-KHALIK: So that considered different break locations, etc.

MR. YODER: No, this was handled differently than the way that if you look at some of the work that's being done for GSI-191 where you look at a series of different break locations and try to identify the most bounding case for debris generated. This was a generic resolution for the BWRs where they said we're going to take this cone, project it out a certain distance and we think that that amount of coating is going to be bounding for any scenario. So all BWRs are using this value of 85 pounds of coating generated in the zone of influence.

MEMBER ABDEL-KHALIK: So if I have a steam line break, for example, what would be the blast field area for that?

MR. YODER: As I said, talking about BWRs, their licensing basis, the way this thing was resolved for resizing of strainers, it's going to be the same regardless of the break location, regardless of the plant. You're going to take that, what they believe is a bounding, what was agreed on at the time by the staff, as a bounding amount of qualified coating debris generated from that pipe break. It happens to be 85 pounds is the number that was agreed upon at the time. Regardless of the break location, that is going to the debris source term generated from the zone of influence for coatings.

Similarly, ZOI calculations for all other materials, all the different kind of insulation materials in containment and I can't speak to the method that those calculations performed. I can tell you about what was done with the coatings. I don't know exactly what was done for insulation type debris.

MEMBER ABDEL-KHALIK: Can somebody here tell me how they got 741 square feet of blast field area:?

MEMBER CORRADINI: Plus or minus a foot.

MR. YODER: Yes.

MR. WOLCOTT: I was the one who threw that number out. J.D. Wolcott, TVA. It is the generic bounding value that was agreed upon as the staff says it was 85 pounds. I took the liberty of translating that while you were talking into square feet which that just translates by the same ratios that are used in the URG methodology that translates into that 741 square feet. But in the guidance document, it's in pounds, 85 pounds.

MR. YODER: This is based on -- As I said, they projected this cone, right, from the break location and this is based on destruction pressures that you would see from a two-phase jet flow is loosely the basis for establishing what this cone should look like, how far it should be projected and what is the surface area of coatings that would impacted.

MR. ABDEL-KHALIK: Thank you.

MEMBER BANERJEE: And the duration of the jet doesn't matter which is why it's independent of power levels. So you have this wonderful power independent whether it's zero power or 100 percent. Thank you.

MEMBER CORRADINI: And just to repeat one thing because you said it earlier to Graham's question, so this is the assumed deterministic calculation and then the generic safety issue, you gave the proper GSI --

MR. YODER: 191 is the --

MEMBER CORRADINI: Will come back, review and may influence this or may not depending on what occurs there.

MR. YODER: Staff is currently looking at what are the differences in the way this issue was resolved --

MEMBER CORRADINI: I understand.

MR. YODER: -- for BWRs and the way we're handling it now. If there are significant differences, we will take action.

MEMBER CORRADINI: Okay. Thank you.

CHAIRMAN BONACA: All right. Let's --

MS. BROWN: Let's move on to flow accelerated corrosion. In the area of flow accelerated corrosion, the staff reviews the adequacy of the Licensee's program to predict, detect and monitor wall thinning and piping and components. The generic evaluation identified changes in various fact related variables. However, it expected that these variables will remain within the model parameters. The Licensee evaluated the effects of EPU on previously-inspected components and adjusted inspection schedule to account for any changes in the remaining life of the component.

MEMBER ARMIJO: I have a problem with the wording there. You said process variables should remain within the FAC model parameters. Hasn't somebody done the analysis to say that they do remain within? That's really what we're looking for that, yes, somebody has looked at it and it's going to be okay.

MR. YODER: Yes, as part of the staff's review we asked for each of these areas, flow velocity, temperature, moisture, oxygen, pH, what is the expected increase specifically on the systems that are most prone to FAC? What is expected increase or decrease? Do you expect an increase or decrease in FAC based on that and is that change in each of those process variables going to remain within the CHECKWORKS model? CHECKWORKS is the model that's used to predict FAC and the answer is yes. It is expected and I believe the reason says it should remain as banning some change that if you see a velocity increase that's greater than what was predicted that obviously would fall outside of the review the staff performed.

MEMBER ARMIJO: But you know the answer is they do remain within the parameters.

MS. BROWN: I'm sorry. When we made that slide up, we were just talking about what we would expect to see as a result of the power uprate and then we were going to get into what actually was seen for

Browns Ferry. So this is just to give you an idea of what the uprate affected the system and then --

MEMBER ARMIJO: But this wording is very hard to follow.

MS. BROWN: Yes.

MEMBER ARMIJO: I'd like conclusions rather than expectations.

MS. BROWN: Yes, and we'll get to conclusions.

MEMBER POWERS: Let me understand. A point was raised I believe yesterday by one of the speakers from TVA. My understanding is that for Browns Ferry Unit No. 1, my interpretation of his comment was that for Browns Ferry Unit No. 1 they looked at the critical locations that they had encountered within Units 2 and 3 and then prescribed that those critical locations because of geometric similitude, I suppose, would also be monitored in Browns Ferry No. 1. Did I understand that correctly?

MS. BROWN: Bill.

MR. CROUCH: This is Bill. What I was talking about yesterday was what -- We went over in the Units 2 and 3 and found places where we had had to replace piping because of FAC.

MEMBER POWERS: Right.

MR. CROUCH: And if it was at a particular type of geometry, we then went into Unit 1 and found every place that had that type of geometry in that system and replaced that piping. We didn't wait to see if we would develop it in another location.

MEMBER POWERS: Yes. I believe --

MR. CROUCH: The monitoring will be set up based upon the calculations that come out of the CHECKWORKS and it will be based upon geometries and flows and everything which has been adjusted for, in this case, EPU conditions 120 percent.

CHAIRMAN BONACA: But even for CHECKWORKS, still the inputs come from Units 2 and 3. You have no experience for Unit 1.

MR. CROUCH: They are out there taking actual pipe thickness measurements that will feed into Unit 1 and obviously all the systems have been inspected prior to restart. So we know there's no problems at restart and we made sure that the materials are such that we know they will last at least a cycle and we will start taking measurements, the official post operational measurements, at the next outage.

MEMBER POWERS: Let me ask you a question just out of curiosity. CHECKWORKS suffers from the fact that it's a totally empirical type of model at best is an interesting term for CHECKWORKS. Did you spend -- Have you ever spent any time looking to see if there's something better out there? I mean the problem with CHECKWORKS is episodically we discover something that is not included in the CHECKWORKS database.

Usually that discovery, not usually, but occasionally that discovery is rudely made and because CHECKWORKS is really not very predictive. It's interpretative. I'm just wondering if as an agency you had looked for anything better.

MR. PHILLIPS: This is Robert Phillips. Let's see. Where do I begin? We started back in 1986 with the Surry event and with the Surry event at that time, I think, EPRI had already developed the first original model which is CHECK and there were other companies out there developing software at the same time. Some of them used particle transport and all kind of stuff like that. And through the years, we've gone through. We've attended all the industry meetings and so far it looks like CHECKWORKS is the best thing that's out there on the market. But we have looked at other things in the past and considered those.

MEMBER POWERS: I just ran across something not too long ago that suggested to me that the Taiwanese were trained and developed a predictive model. I just wondered if anybody else had tried to do that. You know as much about it as I do or you know more about it than I do, I'm sure. But pass that on. Thank you a lot.

MEMBER WALLIS: Can I ask a question now? I got a bit frustrated by these statements I see in the SER that things are going to be okay because we're going to use FAC and it's going to make useful predictions and everything will be monitored. It would help if there was some indication of what sort of predictions are being made. Now does FAC predict an increase in a sort of steady way with velocity and does CHECKWORKS say it proportional to velocity, so that if I increased by 20 percent and I'm predicting one mil per year I'll get 1.2 mils per year. That's not a critical thing.

But if FAC says that there's a certain velocity where the flow regime changes and the rate of a wear increases tremendously, then I'd want to know is that going to be approached in the power uprate. Until you tell me something about what FAC is predicting, I don't really know what to say. Just saying they're using what CHECKWORKS is predicting, saying they're using CHECKWORKS doesn't tell me anything about the implications of going to higher power. What are those implications for FAC?

MR. YODER: As part of our review, one thing that we asked TVA to provide was a list of components, nominal thickness, the thickness that would be predicted by the FAC model and then the actual measured thickness over that period of time and in the majority of those cases the CHECKWORKS program number was bounding of what was actually found. For the ones that were not bounded, they were within the error of the program.

MEMBER WALLIS: Yes, so CHECKWORKS has a good history. But when you go to 20 percent higher velocity or whatever it is, does this increase FAC very much or what? I mean what kind of effect does it have.

MR. YODER: I understand the question. You're asking if there's some step change in any of the process areas.

MEMBER WALLIS: Well, I don't know. What kind of a change is predicted? Is it a nice smooth one? Is it proportional to velocity? Does it go as velocity to the $10^{th}$ power or what does it do?

MEMBER BANERJEE: For example, if the transition to turbulence from a laminary then there would be a step change in corrosion. Is there some region where this is happening, just as an example, or a vortex which is held in a pipe which is --

MEMBER WALLIS: The flow regime changes in some way. Right? Does CHECKWORKS put that in?

MEMBER POWERS: It's been an enormous amount of time since I've looked at CHECKWORKS, but it includes a set of equilibrium type of chemistry models and then it includes a set of geometrical factors and those geometrical factors are trying to identify areas where there are peculiar flow conditions that will cause acceleration. I see maybe someone that has looked at more recently than I. Maybe you want to elaborate.

PARTICIPANT: I believe you've covered it pretty well.

MEMBER POWERS: Maybe. Yes, I mean it's kind of an empirical --

CHAIRMAN BONACA: An empirical --

MEMBER POWERS: -- thing and what they do is they have a library of things that says this kind of geometry we see flow acceleration corrosion and there is a bunch of them. I mean there's a slug of them in there.

CHAIRMAN BONACA: I think the critical issue is the one that was reported there. That is we go for a cycle and then to take measurements in susceptible locations.

MEMBER POWERS: And that was a fed-in to your particular version of CHECKWORKS.

CHAIRMAN BONACA: That's right and to develop because if anything is empirical, there is just to develop a database that is applicable to the unit and here the experience from 2 and 3 is going to be helpful because of similar geometry in the piping.

MEMBER WALLIS: So you're not going to give any numbers or anything or any prediction which says the number now is or numbers from 2 and 3 are this and so therefore you're going to convince us that everything probably okay. There's no crisis for another 50 years or something.

It's all so vague in terms of specifics. You're not going to tell us any specifics like that. You're going to say they're using CHECKWORKS and they're going to check things. So this is all right.

MR. YODER: I think the bottom line here as was stated is much of this is going to be dependent on the measurements that are taken after an operating cycle to show that there isn't some kind of a step change based on any of those process variables that was unexpected.

MEMBER WALLIS: What I would sort of like to see would be a conclusion which is supported by evidence that FAC is not a problem at least for 20 years or something like that. But you can't do that for me?

MS. BROWN: Sir, I believe what we looked at was the adequacy of the Licensee's program to predict FAC.

MEMBER WALLIS: That's right.

MS. BROWN: Right, and that whether or not it would predict FAC in enough time for them to go in and do what they needed to do to correct it. So I believe what the staff has said and what we're proposing is that we took a look at the program that was used on Units 2 and 3 and ensured that it was adequate to predict the flow accelerated corrosion based on the inputs provided and from that, the staff concludes --

MEMBER WALLIS: Yes, because they've gone through the right program. It's all right.

MS. BROWN: Because we were validating the methodology and not the outcome.

MEMBER WALLIS: I think dealing with other plants we have seen numbers.

MEMBER POWERS: Here I think I'm more sympathetic with the staff on their vagueness on it because there we say CHECKWORKS kind of a generic thing. Very quickly, the CHECKWORDS model they have becomes peculiar to that unit and unless you wanted to double this by putting out the predictions of CHECKWORKS for the susceptible piping system and whatnot, it really is kind of infeasible for the staff to write these things down and say -- I mean really the only thing they can do here is say, "They're doing CHECKWORKS and they're using it in kind of the way we would expect it to be used." I mean that's really the only feasible thing.

MEMBER WALLIS: But isn't it like Units 2 and 3? So you do have a basis.

MS. BROWN: Yes sir.

MEMBER WALLIS: And these, for some reason they believe is going to be very different.

MEMBER POWERS: I mean --

CHAIRMAN BONACA: They communicated that from the review they've done with a few exceptions CHECKWORKS for Units 2 and 3 has provided a conservative estimations.

MEMBER WALLIS: That's right. So it's a good tool. It's been validated and all I'm asking is what sort of thing does it predict for the power uprate and I think you could probably give some numbers which would be very reassuring. But those numbers don't seem to be available.

MS. BROWN: I believe that as part of what we were going to say is that they presented some data from Units 2 and 3 and the Licensee found that the system predicted experience with the greatest increase in wear rate. As a result the EPU was on the feedwater heater drains. I think on the unit, was it the three and four feedwater heaters? The increase in the predicted wear associated with the heater drains was around 19.4 percent which was due to the increase in temperature and an increase in the flow rate. That sort of gave us a sort of a little better feel that it was --

MEMBER WALLIS: And the wear rate wasn't very large before presumably. So a 20 percent increase is not significant.

MR. YODER: It's not significant. I think that what the staff is trying to say here is we have assurance that the program that the Licensee is using, the sampling that they're performing, the computer codes that they're using, are going to identify any problems, any degradation out of the normal in a timely enough fashion that they will be able to make their repairs, make the changes, on those components.

MEMBER POWERS: Given, of course, that that particular location where that accelerated row has been experienced and found before.

MR. YODER: Right.

MEMBER POWERS: Let me make it very clearly. I think CHECKWORKS is hopeless because it lacks the predictive capacity and I think it's unfortunate that as a technical community we've become satisfied with CHECKWORKS. For the purpose of this program, it's adequate. But from a long-term perspective, there really ought to be something a lot better than that because too often we find holes developing in pipes that were not predicted using CHECKWORKS.

MR. YODER: Right.

MEMBER WALLIS: And sometimes isn't this in two-phase regions or is all this single phase?

MR. YODER: Single phase.

MEMBER WALLIS: It's all single phase? It doesn't predict what happens with two-phase impingement.

MS. BROWN: Robert, did you want to --

MR. PHILLIPS: Yes. The FAC model, it predicts a single phase and a dual phase.

MEMBER WALLIS: And two-phase?

MR. PHILLIPS: Well, two phase is a dual phase. Yes sir.

MEMBER WALLIS: Because I think places where you have had unexpected high wears are very often the two-phase regions where you have impingement of high velocity drops and I didn't know if there is any change in that in someplace in the plant with uprate or not. But maybe we should move on. I just would have liked to have seen something a bit more specific in this area.

CHAIRMAN BONACA: We need to try to make some time.

MEMBER WALLIS: Yes.

CHAIRMAN BONACA: We're well behind.

MS. BROWN: Yes sir. If we -- Our next topic is reactor water cleanup system and I'll try to go through this a little faster. The uprate effects for the reactor water cleanup system -- The reactor water cleanup system provides a means for maintaining reactor water quality. Portions of this system are part of the reactor coolant boundary. Under uprated conditions, the system will see an increase in temperature flow and pressure, all of which remain within the design of the system. Additionally, the quantity of fission and corrosion products in the water may slightly increase.

That staff's review focused on verifying that the provisions of Standard Review Plan Section 548 and the associated draft design criteria continue to be met by ensuring that the reactor coolant pressure boundary has been designed, fabricated, erected and tested so as to have an extremely low probability of rapidly propagating fracture, maintains the means to control the release of radioactive effluence and that the system design assures appropriate radioactivity confinement.

And from our review, we found that consistent with the generic topical report, the staff found that the reactor water cleanup system is adequately designed to bound all power uprate effects and therefore will continue to perform its function of removing solids and dissolved impurities. The staff found that this conclusion was applicable for all units at up to 120 percent.

MEMBER WALLIS: Are there any effects of any significant due to power uprate on the system?

MR. YODER: You're going to have increased impurities because you're going to have increased feedwater flow. So you may have change the resins more frequently, back-flush more frequently and that's something the Licensee will --

MEMBER WALLIS: There's no iron in dissolved, is there?

MR. YODER: Correct.

MEMBER WALLIS: Right. So you're just changing the resin more frequently. That doesn't seem to be a safety issue. I guess TMI had started in cleanup system. Okay.

MS. BROWN: All right. If it's okay, we want to move on to electrical or did you want to take a break?

CHAIRMAN BONACA: I think so. We have scheduled a break for 10:15 a.m. So why don't we just -- How long will it take?

MS. BROWN: There are very few slides and this is an area where we should be able to step on.

CHAIRMAN BONACA: Let's do electrical and then we'll leave instrumentation and controls for after the breaks.

MS. BROWN: Okay. You want to do electrical and leave instrumentation.

CHAIRMAN BONACA: No. I said we would do instrumentation and controls after the break.

MS. BROWN: I understand.

(Off the record discussion.)

MS. BROWN: Okay. An area of electrical, engineering and instrumentation controls, typically the power uprate modifications occur to support the increased electrical output. For the most part, these components or systems are not significantly affected and therefore, no modifications were required. For example, we see that the diesel generator loading, a lot of the AC onsite systems, the DC batteries, the unit aux and start-up transformers, recirculation condensate and condensate booster pumps, as far as the 105 is concerned, were relatively unaffected by the power uprate. However, as it was the Licensee's original attempt to restart Unit 1 at 120 percent, various modifications were installed but were not required to be installed for the 105 percent uprate.

Most of the modifications planned are intended to support the change in load demand due to large motor replacement, upgraded the generator and switchyard components. As indicated, the Licensee intends to replace both the condensate and condensate booster pumps in support of the generator uprate, the main bank transformers, main isolation phase duct, bus duct, and main generator breaker. In order to provide greater operating flexibility, Licensee has also proposed upgrades in the switchyard buses, breakers and switches.

Operation at EPU conditions requires the modifications of several large motors. The Licensee performed load flow and short circuit calculations were performed to verify the adequacy of the onsite electrical system. This review found that the existing protective relay settings can accommodate the increased load on the 4 kV system and that selective coordination was maintained between the pump and 4 kV Unit 4 main feed breakers.

Some of the more major issues that are normally seen in the area of electrical deal with the grid stability, station blackout and environmental qualification. I believe we already talked about grid stability yesterday.

MEMBER SIEBER: Yesterday.

MS. BROWN: The staff's review focused on the increased electrical output and plant load to ensure that the existing rating and requirements are met for the safety equipment and the existing qualification of safety related equipment was maintained. This was accomplished using the following acceptance criteria, 10 CFR 50.49 as it applies to environmental qualification, 50.63 as it deals with the loss of all alternating current and General Design Criteria 17.

As the review found that the modifications and changes to the electrical distribution system support safe operation or remain within the previous capability of existing components, the staff found that these areas are adequate to support operation of all the Browns Ferry units at either 105 or 120 percent operation.

Do you want to break here or did you want to go on into instrumentation?

CHAIRMAN BONACA: Well, since you went so fast, let's go into instrumentation.

(Several speaking at once.)

MS. BROWN: Keep going. Excellent.

MEMBER WALLIS: You're on a roll.

CHAIRMAN BONACA: We'll ask questions if we come to that.

MS. BROWN: Let's roll on through. Excellent. The topical report guidance concerning instrumentation and controls suggests consideration of the methodology used to determine the set points and review of the following analysis. Several set points were looked at, high neutron flux, vessel scram and recirc pump trip, main steamline isolation, the turbine generator trip scram, feedwater flow set point and the MSIV closure. The staff used the following criteria as the basis for our review, 50.36, 50.55(a) and Draft General Design Criteria on Qualities and Standards, the Environmental and Dynamic Controls, Instrumentation and Controls, as well as several draft GDC addressing reliability and testing of protective systems.

MEMBER SIEBER: There were no real changes to the I&C system, were there?

MS. BROWN: No sir.

MEMBER SIEBER: So if it met them before, it meets them now.

MS. BROWN: It meets after. That's essentially what we're getting ready to say.

MEMBER SIEBER: Okay. You can say it.

MS. BROWN: Thank you, sir. In four slides or so. The staff's review was conducted to ensure that the systems continued to meet safety functions. This can be demonstrated in part by ensuring that the methodology used by the Licensee ensures that appropriate margins are set, calculated set points are maintained within the established setting tolerance and the set points are selected to ensure that the value selected does not significantly increase the likelihood of a false trip or a failure to trip upon demand.

Back in 2005, the staff expressed our concerns regarding the industry set point methodology to ensure compliance with 10 CFR 50.36. Many licensees rely on administrative controls to reset the instrument trip set point to a limiting trip set point or a value more conservative than limiting trip set point at the conclusion of periodic testing. But these controls may be in documents that are not required to be implemented. As these uncertainties are accounted for in the calculations of the limiting trip step point, the limiting trip set point is seen by the staff to protect the safety limit. Therefore, where a limiting safety system setting is specified for a variable in which a safety limit has been placed, the setting must be so chosen that the automatic protective action will correct at normal situation before a safety limit is exceeded.

MEMBER WALLIS: Excuse me. Do you have instrumentation on the steam dryer?

MS. BROWN: The Licensee has installed

instrumentation on the Unit 2 steam dryer.

MEMBER WALLIS: And there are --

MEMBER SIEBER: On the steam lines.

MS. BROWN: I mean steam lines.

MEMBER SIEBER: Not the dryer.

MEMBER WALLIS: Steam lines.

MS. BROWN: I'm sorry.

MEMBER WALLIS: And there is some sort of set points that say when fluctuations become too big, you do something.

MS. BROWN: Yes sir. There are.

MEMBER WALLIS: You have gone over those?

MEMBER SIEBER: Criteria, not set points.

MS. BROWN: Well, the Licensee will establish the acceptance criteria.

MEMBER WALLIS: But we don't quite know yet what's going to happen with those.

MS. BROWN: No sir. We'll probably be going over that and how they're going to deal in March.

MEMBER SIEBER: They haven't told us.

MEMBER WALLIS: But there has been a modification in that there's been more attention paid to what happens in the steam line and possible oscillations.

PARTICIPANT: Yes.

MEMBER WALLIS: Has there been an effort to improve the instrumentation detecting possible fluctuations in the steam dryer and the steam line?

MS. BROWN: I'll let Bill speak to that.

MEMBER SIEBER: Yes. Yesterday they talked about taking advantage of the Vermont Yankee experience, but I'm sure TVA could tell us a little bit more about that if they would.

MR. CROUCH: If you want to talk about it now or we can wait until the steam dryer section.

MS. BROWN: Yes. Actually we were going to sort of touch on that.

MEMBER WALLIS: You're going to deal with that later?

MS. BROWN: Yes sir.

MEMBER WALLIS: Okay.

MS. BROWN: If that's okay. Accordingly, limits for instrument channels that initiate protective functions must be included in the tech specs. When these variables are modified, the Licensee must demonstrate that the allowable value has been suitably chosen to protect the safety limit. For Browns Ferry, TVA used a plant-unique alternative as the industry proposal is still in discussion with the staff. This alternative was reviewed early last year under a separate amendment where the approach was found acceptable.

CHAIRMAN BONACA: This safety limits which you are discussing here, the set point, they are all at 105 percent power.

MS. BROWN: For -- The staff has reviewed the set points both for the 105 and the 120 for Unit 1 and the 120 for Units 2 and 3.

CHAIRMAN BONACA: Okay.

MEMBER ABDEL-KHALIK: Can you tell us how the vessel scram and the recirc pump trip set points were changed and why?

MS. BROWN: Bill, would you like to --

MR. CROUCH: The recirc pump trip set point being the set point that trips on high pressure, that value had to be raised because of the reactor vessel pressure going up 30 psi. So we raised that set point. I don't remember if it was exactly 30 psi, but approximately 30 psi. What was the other one you asked about?

MEMBER ABDEL-KHALIK: The vessel scram.

MR. CROUCH: The vessel scram on high pressure, that was also scaled up approximately 30 psi to account for the pressure increase.

MEMBER ABDEL-KHALIK: So only the high pressure scram was changed.

MR. CROUCH: That's correct.

MEMBER WALLIS: You flipped over to No. 15, did you?

MS. BROWN: Yes sir, I did because this was actually what we were going to talk about on slide 16. Because the only thing that we were doing with slide 15 is to talk about the fact that there were no hardware modifications.

MEMBER WALLIS: It was on 15. That was where I picked up the bit about the steam line. I think you are modifying instruments on the steam line because of concerns with the effects of power uprate on the dryers.

MS. BROWN: As far as the steam lines, like I say, we were going to address how that instrumentation --

MEMBER WALLIS: But when you have a bullet which says "No modifications to instruments for power uprate" there are a few places where there have been some changes as a result of the power uprate. Is that not so and particularly in the steam line?

MEMBER SIEBER: Another important question to ask is whether the instrumentation on the steam lines is going to be permanently installed or just installed to gain assurance that the steam dryer is going to stay together and perhaps TVA could tell us that.

MR. CROUCH: When we did the uprate and I think I understand what their bullet there means, we did not have to change out any instruments because of doing uprate. Obviously we reset instruments based upon new set points to account for higher flows or higher neutron fluxes like that. We have added in temporary instrumentation to monitor the steam lines.

MEMBER WALLIS: So you have modified, but it's only on a temporary basis?

MR. CROUCH: There are strain gauges put on the steam lines. They are not intended to be permanent plant instrumentation.

MEMBER SIEBER: And actually in the plant lists of equipment, they would not appear because they are temporary test instruments.

MR. CROUCH: That is correct.

MS. BROWN: Yes sir.

MEMBER SIEBER: So they don't have mark numbers of anything like that.

MEMBER WALLIS: Well, I'm a bit surprised it's temporary. I mean you're assuming that if there's no problem in the first year, there will never be a problem or something. So you take instrumentation off.

MEMBER SIEBER: That would be the assumption.

MEMBER WALLIS: That's not really true. If it's a fatigue failure of something, it could actually develop later on and then this might show up as fluctuations in the steam line.

MEMBER SIEBER: That's something we may want to consider.

MS. BROWN: And it may be better --

MEMBER SIEBER: My understanding was that was all temporary stuff.

MS. BROWN: Yes sir.

MR. CROUCH: That's correct.

MEMBER WALLIS: I have a question for you. This background is a keyboard, right, the background of your slide?

MS. BROWN: Yes sir.

MEMBER WALLIS: And someone has selected five percent as an appropriate background.

MS. BROWN: You're very observant.

(Off the record discussion.)

MEMBER CORRADINI: That was there just to try to psychologically affect us.

MEMBER WALLIS: Yes, I think it is.

MEMBER SIEBER: Five percent makes sense to me. The four dollars does not.

MEMBER CORRADINI: It's always been there.

CHAIRMAN BONACA: And nowhere it shows 20 percent.

MS. BROWN: Yes.

MEMBER WALLIS: Not yet.

PARTICIPANT: Where's the 20 key? Put it up there.

MS. BROWN: I'm sorry.

MEMBER CORRADINI: I think at 60 Hz 20 is flashing in front of you. You just don't realize it.

MS. BROWN: Yes sir. I have her switch it so it flashes that.

MEMBER ABDEL-KHALIK: So there are no analog instruments that would peg out as a result of changes in any of the parameters in this system.

MR. BURRELL: That's correct. This is Dave Burrell. We've scaled all the instruments ensuring that they would function properly with the uprate.

MS. BROWN: And so all we're saying is there were no hardware modifications as in they needed to change, physically change out, an instrument as a result of the power uprate. Although as were indicated, they did have to do revisions to various set points as to reflect the increased --

MEMBER WALLIS: There's no need to change the response time of some of these instruments in the case of transients that might be more rapid with the power uprate.

MS. BROWN: Are you referring to the operators' response time?

MEMBER WALLIS: No, the instrument. The instruments have a response time. Sometimes what you see on the instrument is what happened ten seconds previous.

MEMBER SIEBER: -- 60 percent, yes.

MEMBER WALLIS: And there's no need to do that.

MEMBER SIEBER: There were no changes.

MR. BURRELL: There's no change in response time.

MEMBER SIEBER: That I saw.

MS. BROWN: And that's pretty consistent with that.

MEMBER WALLIS: It's not needed. You have checked that it's not needed or you just accept it without question?

MS. BROWN: Well, part of our base assumptions were already performed as part of the General Electric extended power uprate licensing topical report. So a lot of the assumptions that we're using are based on that first or initial review. So those aspects were covered in the initial safety evaluation approval of that topical report. So that's one of those assumptions. So what we do --

MEMBER WALLIS: Okay. Your assumption is that the report applies. But in the report, it's actually evaluated whether or not there's a need for any more rapid response of instrumentation.

MEMBER SIEBER: Well, they would not change the response of the instrument because that's sort of inherent in the way the instrument is built. They would lower the set point that it would trip earlier.

MEMBER CORRADINI: Make it more sensitive.

MEMBER SIEBER: I can't recall in any scaling manual that anybody ever did that.

MR. BURRELL: That's correct.

MEMBER ABDEL-KHALIK: Are there any parameters that the operators are required to monitor during emergency conditions that would force a parameter to be outside the range of any instrument when operating at 120 percent power?

MS. BROWN: Dave.

MR. BURRELL: No, there's not. All the instruments would be on-scale as they've been. They've re-scaled for 120 percent and for any emergency condition, they would be on-scale and no operator action to compensate.

MS. BROWN: I think we've probably already hit all of that for 120 percent. As far as the 120 percent review, the similar Unit 1 since credit is not taken in the transient analysis for these two functions, these functions are not safety-limit related and therefore there was no need to provide additional controls. To ensure the acceptable margin to the safety limit consistent with the set temper 2006 approval is required.

The staff found that the allowable value changes acceptable as allowable value changes used a methodology accepted to the staff. The values selected were conservative to the calculated values which ensured the set point changes maintain sufficient margins between operating conditions and the trip set points and do not significantly increase the likelihood of a false trip or failure to trip upon demand.

MEMBER WALLIS: So did you evaluate this likelihood?

MS. BROWN: I'm sorry.

MEMBER WALLIS: When do you say "do not significantly increase the likelihood" how big is the likelihood and what's the increase in it? Is this a judgment or is this based on analysis?

MS. BROWN: This is an engineering judgment.

MEMBER WALLIS: So you just think that that's true.

MS. BROWN: We believe it's consistent with what we saw, what was approved, in the topical report.

MEMBER WALLIS: But there's no attempt to evaluate the increase in likelihood of a false trip? Just somebody guesses that that's probably the answer or does someone now analyze it?

MEMBER SIEBER: Look at changes.

MEMBER WALLIS: It's an engineering judgment or does somebody --

MS. BROWN: Yes sir, it's an engineering judgment.

CHAIRMAN BONACA: What you're saying is

that process parameters come closer to the trip set points.

MS. BROWN: You're talking about the set point methodology. That was part of what the --

CHAIRMAN BONACA: I'm talking about maintaining sufficient margin between theoretical conditions and the trip set points.

MS. BROWN: Yes sir. And that's part of what the staff evaluated when we looked at the set point methodology back in September.

CHAIRMAN BONACA: Yes. But in the context of this statement, what do you call a false trip?

MS. BROWN: What do we call a false trip?

CHAIRMAN BONACA: Yes.

MS. BROWN: I don't know --

MEMBER WALLIS: If this greater noise can be created by this uprate for instance, greater noise, you might get more false trips because the stepping over some --

MEMBER SIEBER: BWRs you get $\Delta T$ trips that are sometimes false because the signal is noisy.

MEMBER WALLIS: Is this based on experience with other systems, other reactors, or something, other plants? This statement.

MS. BROWN: It's more of a generic

statement.

MEMBER WALLIS: Is it just a guess? I mean is it a guess in the doc? I'm trying to --

MS. BROWN: It is our outcome based on our engineering judgment.

MEMBER WALLIS: But there's no evidence you can give me that will help convince me.

MS. BROWN: Probably not.

MEMBER WALLIS: A look in your eyes, do I have something --

MS. BROWN: No.

MEMBER ABDEL-KHALIK: Has there been any false trips as you define them --

MS. BROWN: Not that we're aware of.

MEMBER ABDEL-KHALIK: -- at Units 2 and 3?

MS. BROWN: No sir. I'm looking at the Licensee.

MEMBER ABDEL-KHALIK: Has there been any false trips as you define them in any plant?

MEMBER SIEBER: You guys would know. We wouldn't know.

MEMBER WALLIS: Upon uprate.

CHAIRMAN BONACA: Especially a plant going through an EPU.

MS. BROWN: No sir. Not that we're aware

of.

MEMBER WALLIS: When you write a statement like this, you're always going to be asked or could always be asked to defend it.

MS. BROWN: Yes sir.

MEMBER WALLIS: And it's useful to have an argument other than the "We believe."

MS. BROWN: Thank you.

MEMBER SIEBER: Usually the argument rests on what changed.

MS. BROWN: Yes and for the most part, nothing has changed.

MEMBER SIEBER: You may not know what the baseline failure rate is and if you didn't change anything, the baseline failure rate isn't going to change. So you look at what you changed and try to evaluate that. That's what the staff should be looking at.

MEMBER WALLIS: Is somebody held accountable? I mean suppose they go up to EPU and they start getting false trips. Is someone held accountable for this statement?

MS. BROWN: The Licensee.

MEMBER WALLIS: You made the statement.

MS. BROWN: Yes sir.

MEMBER SIEBER: It's in the SER.

MS. BROWN: Yes.

MEMBER POWERS: It doesn't matter. The Licensee is still the one that's held accountable.

MS. BROWN: Yes. In the end, they --

MEMBER POWERS: So you can never lose. Get two or three of them and they show up on a little chart where the color turns from green into white or eventually yellow.

CHAIRMAN BONACA: Okay. Shall we take a break?

MS. BROWN: Yes sir. Thank you.

CHAIRMAN BONACA: We'll get back at 10:35 a.m. Off the record.

(Whereupon, at 10:19 a.m., the above-entitled matter recessed and reconvened at 10:36 a.m. the same day.)

CHAIRMAN BONACA: Back on the record. Okay. Before we start with the agenda, there are a couple of representations, one from Mr. Lobel regarding suction strainers. He'll give us some information. These are all questions that were received this morning. And also from Mr. Crouch, I believe, on vortexing, some of the issues that have been raised. So we'll go with you.

MR. LOBEL: This is Richard Lobel of the staff. I'm not sure what the question was. Could somebody state the question?

CHAIRMAN BONACA: Unfortunately the guy that raised the question is not here right now. I could paraphrase, but let's --

MR. LOBEL: I understand it had something to do with the debris generation.

CHAIRMAN BONACA: Generation.

MR. LOBEL: Or maybe I could just --

MEMBER POWERS: I believe this is a presumed misunderstanding. Ah, here he is. I'll let him articulate it himself. Not you. You're up. He needs to know what your question is.

MEMBER BANERJEE: Which question?

MR. LOBEL: On debris.

CHAIRMAN BONACA: On debris generation because there is some -- He can provide some answers to the question raised this morning regarding debris generation, how it was accounted for, the MPSH calculation.

MEMBER BANERJEE: Remember. Is it the issue about how much debris is generated based on there's no accounting taking of the energy deposition or apparently none?

CHAIRMAN BONACA: Or how it was?

MEMBER BANERJEE: Or how it was taken?

CHAIRMAN BONACA: I believe that --

MEMBER BANERJEE: I think I understand how the debris calculation is done which is just to look at a zone of influence and say more or less everything is destroyed within that zone.

CHAIRMAN BONACA: Right.

MEMBER BANERJEE: So it's more or less independent than of how much energy is deposited.

CHAIRMAN BONACA: The question was more how is it accounted in the head calculation.

MEMBER BANERJEE: Well, it goes to the sump then. Right?

MR. LOBEL: There's an assumption of a break, different breaks at different locations or analyzed to find the worst break. The volume of debris in the zone of influence is assumed to be transported to the suppression pool. Depending on what location it is in the containment, there are different fractions of the debris that are assumed to reach the suppression pool depending on the height because there's different floor levels that are going to capture some of the debris. But debris that isn't captured at these different levels is assumed to reach the suppression pool and it's assumed then to be distributed to the strainers and I believe if I remember right the assumption that TVA makes is they determine which strainer receives the most debris and then they assume all that strainers, all four strainers, have that amount of debris. The debris is accounted for in the head loss calculation by determining first the clean screen head loss and then adding the head loss due to the debris to that. Then that head loss is included in the loss term of the MPSH calculation.

MEMBER BANERJEE: Right.

MEMBER WALLIS: And it's a fairly small part of the loss term, isn't it?

MR. LOBEL: Yes.

MEMBER BANERJEE: Well, at the highest flows it's not that small because it's 3 or 4 psi, isn't it?

MR. LOBEL: I don't remember what the numbers are for Browns Ferry.

MEMBER BANERJEE: Right.

MR. LOBEL: It's more than it was for Vermont Yankee.

MEMBER BANERJEE: Yes. And the question I had originally was how much fibrous insulation was there and I think it was answered by saying that there isn't very much because --

MR. LOBEL: The only fibrous insulation is in some of the containment penetrations and that was considered by assuming that the material in the penetration that had the largest quantity released that fibrous material into the, eventually, suppression pool. But when you do --

When there's RMI, you really look at it two ways. You do one calculation with the RMI and you do another calculation with the fibrous material and you determine which one gives the highest head loss. And for Browns Ferry, it was the RMI. They assumed that the strainers are saturated with the RMI insulation.

MEMBER BANERJEE: And the fibers -- In Vermont Yankee, I remember the issue was that when they did the tests with these disks that they looked at single disk pressure losses but then you stack them. Of course, there was an additional blocking effect due to the fibers getting into the interstitial spaces which wasn't properly accounted for.

MEMBER WALLIS: Is that what you mean by saturated? What do you mean by saturated?

MR. LOBEL: Saturated for the given flow, only a certain amount of the RMI is going to remain attached to the strainer and produce the head loss. There's only a certain amount that that's going to stay next to the strainer surface.

MEMBER WALLIS: Saturated, I had -- When I read saturated, I had visions of these things buried in RMI. That's not the case.

MR. LOBEL: No.

MEMBER WALLIS: I still don't quite know what's meant by saturated.

MEMBER BANERJEE: I'm getting the report printed so I can look at it in detail.

MR. LOBEL: Okay.

MEMBER BANERJEE: If we have any questions, we'll get back to you.

MR. LOBEL: In terms of Browns Ferry review, this area didn't get a lot of attention because it's essentially a resolved issue. The staff wrote a letter to Browns Ferry back in 1999 saying we agree with the approach that you took and for the power uprate the questions that were asked were just along the line of is there any difference between what you're doing now and what you did back then for the last review that the staff looked at.

The answer was essentially no. The higher flow rates were looked at. We did ask about the change in the flow rates and they were considered. So we didn't go back and re-review topical reports or the URG methods or all that again. It was just to look at if there had been any changes due to the power uprate.

MEMBER BANERJEE: So they were still drawing through four strainer banks simultaneously when you had that original review.

MR. LOBEL: Yes.

MEMBER BANERJEE: So the geometry hasn't changed.

MR. LOBEL: No, the geometry hasn't changed and for Unit 1, they have made the statement that the strainers are identical to what was installed in 2 and 3 and the methods are identical.

MEMBER BANERJEE: so when you have an increase in power, do the flow rates go up or do the flow rates stay the same?

MR. LOBEL: The pump flow rates?

MEMBER BANERJEE: Yes.

MR. LOBEL: The pump -- Some of the pump flow rates went up. They determined that in the short term LOCA the flow rate of the core spray pumps was higher than what had been assumed before. It was like I presented yesterday around 4,000 GPM instead of

3,000 GPM. For the Appendix R event, there were a couple iterations, but the final flow was around 9,000 GPM.

MEMBER BANERJEE: And for the RHR?

MR. LOBEL: For the RHR pumps, I believe the flows didn't change --

MEMBER BANERJEE: They were around 11,500 or whatever.

MR. LOBEL: Yes. Well, that was for the short term LOCA.

MEMBER BANERJEE: Right.

MR. LOBEL: And then after that, 6,500 and 6,500 was what was used for the other events. But the other events don't have debris in this case. For Vermont Yankee the ATWS event generated some debris but not for Browns Ferry because Vermont Yankee had a relief safety valve that discharged into the containment. So when they did their ATWS calculation for MPSH, they used the LOCA head loss term. But Browns Ferry doesn't have that configuration.

MEMBER BANERJEE: I had a question regarding the head loss due to the debris and I also had a question related to the vortex that would form, both of which --

CHAIRMAN BONACA: -- the vortex I believe.

MR. LOBEL: Right. We've covered the vortex --

MEMBER BANERJEE: But in any case, it's treated in this report. So let me -- I'm getting this report printed out. Let me look at it and if I have some questions --

MR. LOBEL: I'm not sure the report talks about vortexing. You're talking about --

MEMBER BANERJEE: Vortexing.

MR. LOBEL: You're talking about the URG?

MEMBER BANERJEE: No, there is a report on MPSH.

MR. LOBEL: Okay.

MEMBER BANERJEE: I'll tell you where it says. I'm getting it printed, but let me come back to you after I've looked at it if I have some questions.

MS. BROWN: All right.

MEMBER BANERJEE: It's a fairly extensive report. It's TVA BFN TS 431, March 23, 2006.

MR. LOBEL: Oh, is that -- You're talking about the --

MEMBER BANERJEE: Yes, it's a response to NRC request for additional information regarding critical core containment over pressure.

MR. LOBEL: Yes. That was a letter in

response to questions we asked.

MEMBER BANERJEE: Yes, and this is a 400 -- 393 page.

MR. LOBEL: It contained their calculations, their MPSH calculations.

MEMBER BANERJEE: That's what I'm looking at.

MR. LOBEL: Okay.

MEMBER BANERJEE: So once I've looked at it if I have questions, I'll address them to whoever.

MR. LOBEL: Okay.

MEMBER BANERJEE: For the time being, we can move on.

MR. CROUCH: Eva.

MS. BROWN: Yes.

MR. CROUCH: We can tell you for sure that report does not cover vortexing.

MS. BROWN: Okay.

MEMBER BANERJEE: Does not cover vortexing.

MR. CROUCH: It does not cover vortexing, but we have the answer to your vortexing question here if you want to hear it.

MEMBER BANERJEE: Okay. I thought it did for some reason. There is -- Appendix 3 has the ingestion of a steam bubble or plume. That's not the vortexing? Okay.

MR. EBERLEY: Bill Eberley with TVA. With respect to vortexing, our strainer minimum submergence at the upper corner of this device is approximately five feet as I mentioned yesterday and the flow area of the strainer is approximately 298 square feet.

MEMBER BANERJEE: That's what flow area? Is it --

MR. EBERLEY: The summation of the flow through the holes. Right?

MEMBER BANERJEE: What is the circumferential -- This is cylindrical shape. Right?

MR. EBERLEY: Right.

MEMBER BANERJEE: What is the surface area of the cylinder? That's the relevant flow area in this case.

MR. EBERLEY: We don't have that written down anywhere, do we?

PARTICIPANT: No.

MEMBER BANERJEE: Not the individual shacked disk areas.

MR. EBERLEY: Four feet in diameter or something like that?

PARTICIPANT: Yes, four feet in diameter

and four feet long.

MEMBER BANERJEE: It's four feet diameter. How long?

MR. EBERLEY: Four feet long, but it's a series of stacked disks that have --

MEMBER BANERJEE: But those are not relevant because they are shacked. Right? It's the external flow area which is relevant which is Yd whatever.

MR. EBERLEY: Right.

MEMBER BANERJEE: Times d. So it's in this case --

MR. EBERLEY: Effective flow area relative to the approach velocity is approximately 300 square feet and it gives an approach velocity of six feet per minute.

MEMBER BANERJEE: Well, but that's not what -- If it's four feet in diameter and four feet long, it seems to me it's closer to 12 times 4 which is about 50 square feet if I'm roughly right. So that's -- You should get the approach velocity based on that, not on the individual flow areas because that's what's sucking. Right? I mean we can draw and discuss it, but it's clear.

MR. EBERLEY: Okay. Based on a 300 square foot area and we can debate whether that's the area or not but based on that area and the maximum flow in the short term through one of these strainers of 13,500 gallons per minute approximately, the FRD number comes out to be 0.008 and the FRD number is less than about 0.6. Vortexes break up so that we feel like there's essentially no potential for a vortex to form at the surface by --

MEMBER BANERJEE: Do it slightly differently now.

MR. EBERLEY: Okay.

MEMBER BANERJEE: Because only the top half is operational. Multiply it 12, that number. You'll get roughly the right FRD number then.

MR. EBERLEY: And what is your basis for the top half being --

MEMBER SIEBER: I don't think so.

MEMBER BANERJEE: Because that's what's sucking. Right?

MR. EBERLEY: The whole strainer is in play here. Right?

MEMBER BANERJEE: No. They are stacked disks.

MEMBER SIEBER: If you go all the way around, it's drawing fluid.

MEMBER BANERJEE: Yes, but from the point of view of what's happening to the surface it's the projection of the velocity field that matters. Right?

MR. EBERLEY: The strainer is designed to have essentially a uniform intake velocity over its parameter.

MEMBER SIEBER: Regardless of the -- position.

MR. EBERLEY: And these stacked disks are not identically the same. They get -- The inner diameter gets smaller as you go inward, outward, away from the suction pipe.

MEMBER BANERJEE: But if you look at it from the effect on the surface, okay, what the stacked disk looks like is a cylinder into whose walls a flow is going.

MR. EBERLEY: Correct.

MEMBER BANERJEE: What we're really trying to look at is the velocity field based on the surface area of the cylinder.

MR. EBERLEY: Right.

MEMBER BANERJEE: This is what's sucking the surface down. In fact, if you look at the velocity field around it, there will be some sucking from the sides, but it's like behind the wake of a cylinder. So really it's the projection of the area of the cylinder that you have to look at. The projection of the area is strictly $d^2$. So it's 16 feet squared and the velocity if you calculate it based on that, you took 360 squared. So it's a factor of 20 higher, the approach velocity.

MR. EBERLEY: And the order of magnitude on the FRD number is two order of magnitudes below the threshold, 0.008 versus 0.6. So multiply it by 100 if you will and you're still well below the threshold for a vortex to form. That was the point.

MEMBER BANERJEE: Yes. That may be true but it's a different velocity.

MR. EBERLEY: We're so far below it that in fact it wasn't thought to be a significant issue here.

MEMBER BANERJEE: Okay. Well, I'll revisit this.

MR. EBERLEY: I understand.

MEMBER BANERJEE: And look at it carefully myself.

(Off the record discussion.)

MS. BROWN: Okay. With that, can we -- Is it all right to continue?

CHAIRMAN BONACA: Please proceed now.

MS. BROWN: For this area, the staff review focused on plant operations and maintenance, normal operational environmental releases, the irradiation effects on the pressure vessel internals, offsite doses from design basis of accidents, control room habitability during accidents, the fuel isotopic inventory and the reactor coolant isotopic concentrations.

(Off the record discussion.)

MS. BROWN: Some of the assumptions used in looking at this area was that there was only a small change in the reactor core design that the existing counts for the updated final safety analysis report remained valid and that the radiological data dose is changed only by the magnitude of the change in the radiation source.

The staff's review was focused -- The staff's acceptance criteria was based on 10 CFR 50.67 Part 20, Appendix I to Part 50 and GDC 19 Concern to Control Room as well as accident specific criteria stated in the Standard Review Plan, Section 15 and Reg. Guide 1.183.

MEMBER SIEBER: Does Part 100 affect it at all?

MS. HART: Part 50.67 replaces the

criteria in Part 100.

MEMBER KRESS: Excuse me. I want Slide 3. You went by a little too fast for me. Does that light bullet mean that you took calculated dose that was and upped them by 20 percent?

MS. HART: No, they did not. They recalculated it in a previous submittal asking for an alternative source term.

MEMBER KRESS: They had to recalculate it because the previous FSAR didn't use the alternative source term.

MS. HART: They had a previous alternative source term that included the power uprate level that was approved back in 2004. So that's what's in there currently in their FSAR.

MS. BROWN: Which was a great question because it led us right into our next slide on alternative source term. As Michelle said, the Licensee did deal with that source term issue in a previously submittal that came into the staff on 31st of July 2002. The submittal was for all three units and the staff approved it, approved full scale implementation of alternate source term on September 27, 2004. That approval was for all three units at assuming 120 percent.

MEMBER KRESS: What did they ask for -- What's IAW?

MS. BROWN: In accordance with.

MEMBER POWERS: What did they ask for in the alternate source term? Was it strictly timing or did they actually specify different radionuclide --

MS. HART: They specified all of the criteria in Reg. Guide 1.183.

MEMBER CORRADINI: Dana, can you just tell me a bit more? So they reduced the source terms which are typical on 10 CFR 100?

MS. HART: It changes the fractions of the isotopes in the core that are assumed to be released. It also changes the timing of release from the core to the containment. They additionally took some credit for deposition in the containment in that review and they made sure that the pH was controlled so that they wouldn't have re-evolution of iodine by using the standby liquid control system.

MEMBER CORRADINI: That's all in the 2002 submittal.

MS. HART: That's correct.

MEMBER CORRADINI: Thank you.

MS. BROWN: We're ready. As a result, the staff found that the source trash for the Radwaste system analysis -- criteria and then Part 20 Appendix I to Part 50. And it was consistent with alternate source terms of the radiological consequence analysis in accordance with 50.67 and the standard review plan and as we said before the staff found this area acceptable for the radiological consequences for Units 1, 2 and 3 at 120 percent which was bounding for the Unit 1 105.

MEMBER POWERS: In the course of doing this review, these reviews, these various applications, do you look at the unfiltered leakage into the control room?

MS. HART: Yes, we do.

MEMBER POWERS: Control rooms?

MS. HART: Control rooms, yes.

MEMBER POWERS: And what is the tale of the tape here?

MS. HART: Let me look it up. I do have to confess I did not do the alternate source term amendment review.

MEMBER POWERS: For this plant, I can't think of one that would be easier to do since that the AST was designed for a sister plant.

MS. HART: Right. According to the SE report that was written by my colleague, that the

Licensee did perform testing of the control room, habitability zones, and they used a bounding control room unfiltered and leakage in their dose analysis.

MEMBER POWERS: Yes, the problem is that what the Licensee claims and what actually exists are sometimes two separate things. You're saying that he tested this and so he has a good number and you don't happen to know what that number is.

MS. HART: According to this, the filter testing, I mean, the tracer gas testing, excuse me, determined an in-leakage rate of 3,815 CFM.

MEMBER POWERS: So a pretty high unfiltered in-leakage.

MEMBER KRESS: They have two ways of testing that with the pressure gas. They go around to all the penetrations and see and then add them up or they can inject tracer gas into the whole room and watch it decay with time. Do you know which way they did that?

MS. HART: According to this, their response to the Generic Letter 2003-01 on control room habitability, they responded in December and they had used tracer gas testing, the ASTM method. It does not say which method they used whether it was decay or concentration and in that test they got an unfiltered and leakage rate of only 600 CFM.

MEMBER POWERS: These are still substantial unfiltered and leakages.

MS. HART: Yes.

MEMBER POWERS: Given especially where the control room is located.

MS. BROWN: Bill, did you want to add to that?

MR. CROUCH: Yes. We're checking right now, but just based on our memory, the 3,815 number that you got was an older test and when we did the tracer gas test, it was significantly less than that and we're calling right now to find out what the actual number is.

(Off the record discussion.)

MS. BROWN: Were there any --

MEMBER POWERS: Those unfiltered tests, they can define it anyway they want to. But 600 CFM is a pretty fair -- I mean what you've seen in the original applications are things like 10 and 20. Well, nobody can live with that. So the true number is higher than that and these are -- 3,815 is a healthy one. Six hundred is high.

MS. HART: But not terribly unusual.

MEMBER POWERS: Not unusual.

MS. HART: There are others.

MEMBER POWERS: Yes.

MS. HART: There are others.

MEMBER POWERS: And it has serious implications on control room habitability for 30 days following a DBA.

MS. HART: That is correct.

CHAIRMAN BONACA: We'll wait for the --

MS. BROWN: Yes, do you want to wait?

(Off the record discussion.)

MEMBER WALLIS: Well, 3,500 CFM is a tremendous amount.

MEMBER POWERS: Pretty healthy.

MEMBER WALLIS: Six cubic feet a second, that's a breeze coming through an open door.

MEMBER POWERS: Well, the unit control room probably has 10,000 cubic feet per minute going through it. I mean the control rooms 1 and 2 are the biggest room.

CHAIRMAN BONACA: Do you have that number?

MR. CROUCH: We're just calling right now to get the number.

CHAIRMAN BONACA: Okay.

MEMBER CORRADINI: Six hundred seems reasonable. Three thousand --

MEMBER WALLIS: In the original spec, it's something like 10.

MEMBER POWERS: That's still pretty big.

MEMBER CORRADINI: That's still pretty big, you think, six hundred.

MEMBER WALLIS: Yes.

MEMBER POWERS: Well, you have to put it in context.

MEMBER CORRADINI: Right. That's why I was listening to you saying about 10,000 CFM for the whole.

MEMBER POWERS: And the context that's of interest here is 30 days following a design basis accident where you get the gap release and that gap release has to leak from the containment into the aux building. Now the unfiltered leakage out of the containment for MARK I BWRs actually is pretty low. If it's a MARK III, we'd probably be discussing this a little longer. But for MARK I, I mean how much leakage do you have? There's just not very bad penetrations and whatnot.

Okay. So it's a number. But they pick any number they want. They just have to do the safety analysis and I presume that they have said yes fairly weak and occupy because they require to occupy and man the control room for 30 days following a design basis accident. I think it's safe to assume that it's okay to do that.

MS. BROWN: Bill, did you?

MR. CROUCH: Yes. The number we're going out to get is the unfiltered end leakage that goes into the control habitability zone. This is not any kind of leakage from primary containment to secondary containment. Okay.

MEMBER POWERS: Yes. You're going after the right number.

MR. CROUCH: Okay.

MEMBER POWERS: Thank you.

CHAIRMAN BONACA: Okay. So let's move on with this and then we'll --

MS. BROWN: We'll have that as a follow-on.

CHAIRMAN BONACA: Yes.

MS. BROWN: Radiation protection was covered in staff's safety evaluation Section 2.10. The major areas of review for the staff dealt with increased source term production and as it applies to the public dose and environmental impact related also to the increased effluence, increased (Off the record discussion taking place at the same time.) N16s, C15 and offsite shine. The staff also looked at occupational worker doses due to increased radwaste and the public and environmental impacts of that as well as the liquid and gaseous effluence, solid radwaste and the condensate polisher ion exchange resins. The staff also looked increased core inventory as well as the post accident and worker dose.

MEMBER POWERS: It's not an irrational number.

MEMBER WALLIS: Now this slide is like the SER. 3458 is 105 percent. One hundred and twenty percent is 3952.

MS. BROWN: Yes sir.

MEMBER WALLIS: So it's an incorrect statement to say 3458 is 120. 3458 is 105.

MS. BROWN: Yes sir. And you made us aware of that yesterday and we're going through --

MEMBER WALLIS: But now you put it on this slide.

MEMBER CORRADINI: They were -- There's a time lag.

MS. BROWN: We're still going through the --

MEMBER WALLIS: Which one is it?

MS. BROWN: Well, I'm going to get to that in a second.

MEMBER WALLIS: I didn't see this slide yesterday. I was just making statements that I found this kind of thing in the SER and I didn't --

MS. BROWN: Yes sir.

MEMBER WALLIS: And here it is again.

MS. BROWN: Yes sir.

MEMBER WALLIS: It just supports the evidence.

MS. BROWN: Yes sir.

MEMBER WALLIS: So you didn't correct it?

MS. BROWN: We're going through the safety evaluation and going through and correcting that first.

MEMBER WALLIS: But someone presumably looked at this slide in preparation for the presentation and didn't notice that it was wrong.

MS. BROWN: Yes sir, that's true.

MEMBER WALLIS: Okay.

MS. BROWN: All right. What we're trying to get across with this slide is just that the staff's review was performed with the radiological impacts projected at uprated conditions and therefore, the 105 percent review was bounded by those results.

MEMBER WALLIS: Now the staff used 3952?

MR. PEDERSEN: That's correct.

MS. BROWN: That's correct.

MEMBER WALLIS: And someone has checked that?

MR. PEDERSEN: Actually, in terms of the oxide dose particularly from the increased N16 in the turbine building, the limiting parameter is not NRC regulation. It's EPA 40 CFR 190 which is 25 millirem from the entire fuel cycle. So we had to the shine from all three units operating at 120 percent power of their original licensed power which is only a 15 percent increase from the current license power for Units 2 and 3 but a 20 percent increase from the original and current license power for Unit 1. It was somewhat complex but the bottom line is that we considered the shine and the impact to the members of the public from all three units operating at 120 percent of their original license power. And I apologize for the mistake on the slide.

MEMBER KRESS: Did anybody think to see if the site has a risk that's related to the safety goals QHOs? Has anybody checked to see how far it was from the QHOs up or down?

MR. PEDERSEN: I don't understand the

question.

MS. BROWN: Yes, I'm sorry. I couldn't quite hear you.

MEMBER POWERS: Could they ask you to do something that's impossible to do?

MEMBER KRESS: I quite often do that.

(Several speaking at once.)

MEMBER CORRADINI: That wasn't a test. You can disagree on this one.

MS. BROWN: Thanks.

(Laughter.)

MEMBER KRESS: The question was we have three plants on the site at relatively high power upping the 20 percent and if you did a Level 3 PRA, you could see whether the site meets the safety goals which are not requirements, the QHOs, but it would be nice to know whether it falls well above them or well below and then just out of curiosity, did anybody make that evaluation just to see?

MS. BROWN: That's a great question and Mr. Stutzke will be back.

MEMBER KRESS: He'll be here. He'll tell us.

MS. BROWN: Yes sir.

MEMBER POWERS: He will too.

MEMBER KRESS: Marty will tell us.

MEMBER CORRADINI: Marty knows all.

MS. BROWN: Marty knows -- He's our risk guy.

MEMBER POWERS: You don't want to do this because as soon as Marty gets up there and announces a number Dr. Kress is going to say "Oh, yeah. Did you take into account risk during shutdown operations?"

MEMBER KRESS: You're right.

MEMBER POWERS: "Did you take into account size measures?"

MEMBER CORRADINI: Fire.

MEMBER KRESS: Yes, I'm just setting him up.

MEMBER POWERS: So you are making life miserable for Marty.

MS. BROWN: It's my job.

MEMBER POWERS: Which is an unkind thing to do because he can't retaliate.

MEMBER KRESS: He's such a good guy, too.

MEMBER POWERS: He can't get even.

MS. BROWN: Well, we could turn and ask the Licensee but the risk guys ran out of the room. So we'll leave it at that.

(Laughter.)

MEMBER KRESS: Okay. I'll wait until Marty is in.

MS. BROWN: Let's go on to -- I guess Roger sort of touched on these but these were the acceptance criteria that the staff focused on as part of the review, the 120 dose limit, 40 CFR 190 as well as Appendix I to Part 50 and the guidance provided in NUREG 737, the TMI action item 2B2 on post accident worker dose. In conclusion, the staff found that the radiological protection was acceptable based on the fact that the results of 120 percent review bounded the operation of 105 as well as it met the acceptance criteria we previously discussed as well as the fact that the Licensee's programs assure that any increases will be made as low as reasonably achievable. Therefore, the staff found that the radiological protection area was acceptable for 105 percent and 12-percent for all three units.

Were there any additional questions?

MEMBER WALLIS: How close does it come to what's acceptable?

MR. PEDERSEN: How close does --

MEMBER WALLIS: How close is it to what's acceptable?

CHAIRMAN BONACA: The limits.

MR. PEDERSEN: For the 40 CFR 190, 25 millirem per year, the calculation of all three plants operating at 120 percent power was slightly less than two rem per year. So there's quite a bit of margin there.

MEMBER WALLIS: A lot of margin, okay.

MR. PEDERSEN: Yes. The 10 CFR 20, dose limit, that was 100 millirem. So obviously it's a small fraction of that as well in terms of the public.

(Off the record discussion.)

MEMBER WALLIS: So it's well away from the limits.

MR. PEDERSEN: Yes.

MEMBER WALLIS: Okay. Thank you.

CHAIRMAN BONACA: Okay. So let's move on.

MEMBER POWERS: Just out of curiosity, what's the annual release during normal operations for these plants?

MR. PEDERSEN: I don't have those numbers off the top of my head.

MS. BROWN: Bill, did you guys have the number for your annual release rate?

MR. PEDERSEN: They are a small fraction of Appendix I design criteria which are in the order of 5, 10, millirem a year. Their effluent report which has been more than a year since I reviewed it during the review, but it was a small fraction of that, less than a percent or two of as far as effluence.

MEMBER POWERS: I'm looking for the curies.

MS. BROWN: Bill.

MR. PEDERSEN: I don't have that number. We can get it but I don't have that number.

MS. BROWN: Yes. TVA is going to get back to you, Dr. Powers.

(Off the record discussion.)

CHAIRMAN BONACA: Okay. So we can move on to the presentation on steam dryers, I guess.

MS. BROWN: Yes sir.

CHAIRMAN BONACA: Now we're going to see the engineering.

(Off the record discussion.)

MR. CROUCH: Eva, before you get started.

MS. BROWN: Yes sir.

MR. CROUCH: When you go into steam dryers, you need to be conscious of the fact that if you get into proprietary information we need to know that.

MS. BROWN: I think when we go into steam dryers, it's very high level, regulatory speak.

MR. CROUCH: Okay.

MS. BROWN: If we need to get into details, we'll be mindful to it.

MR. CROUCH: Okay.

MS. BROWN: All right. This presentation addresses the mechanical and civil reviews provided by the staff and the staff's safety evaluation Section 2.2. These analyses were performed by the Licensee at 120 percent. Therefore, this entire discussion is applicable for all units at 120 percent and completely bound to Unit 1 105.

For power uprate, the unit sees increased temperature and pressure. As part of the review, the staff evaluates the structural integrity of the pressure retaining components including the nuclear steam reactor pressure vessel internals and core supports, the seismic and dynamic qualification of equipment as well as a review of the steam dryer and potential adverse effects.

The staff's evaluation found that all effected components and supports were evaluated and an analysis performed consist with the extended power uprate licensing topical reports. The staff also found that seismic loads remain unchanged and the original LOCA dynamic loads including pool swell, condensation, oscillation and choking remain bounding up to 120 percent and the calculated stresses and cumulative fatigue usage factors were less than the Code allowable limits.

MEMBER POWERS: When you say that you found that the seismic loads remained unchanged, you looked around and said "Gee, I can't understand how all this new hardware they're going to bring in is going to change the frequency."

MR. WU: Seismic analysis is simply not affected by EPU. So the stress below they have in the past. It's still valid. It's still applicable.

MEMBER POWERS: But if we look at --

MR. WU: For Unit 1, Unit 1 the use -- That's a good question. Unit 1, the use of seismic, the previous seismic, and use of older load combinations for the analysis.

MEMBER POWERS: But if we look at the seismicity of the east coast as it's concerned today compared to when the FSAR was written for these plants, what do we find?

MS. BROWN: Kamal.

MR. MANOLY: This is Kamal Manoly. I'm the Branch Chief for the Civil and Mechanic Branch.

The seismicity issue really has no relevance to this power uprate review. I mean the plant is licensed for certain seismic requirements and that's what we expect them to stick to. The new seismicity affects the new plants which we're not discussing right here.

MEMBER POWERS: I presume the seismicity affects all plants.

MR. MANOLY: In terms of --

MEMBER POWERS: And you can talk to me legalistically about what seismicity you'll take into account, but the fact is that the new assumptions, the current state of the art, on seismicity is in fact applicable to the existing plants.

MR. MANOLY: No, that's correct. I'm not saying that unless it changes. But it does not change the licensing basis for this plant. I mean if we want to consider whether the -- perhaps we change the licensing basis because of new information on seismicity, that's a whole different discussion. I think John was trying to articulate that the seismic analysis was unaffected by power uprate because the structural model is essentially the same. The masses are essentially the same and they basically are following whatever they're licensed for.

MR. WU: The EPU, no more from the ERTR,

the topical reports, we are committed to evaluate the difference between the EPU and the current operational systems or current conditions which is --

MEMBER POWERS: But it seems to me --

MR. WU: That's why the design basis. The design basis is the one. The seismic is the use in the design basis which you consider that's important for this EPU use.

MEMBER POWERS: You probably have correctly outlined the task of this job, but the job of the staff is also to assure adequate protection of the public health and safety. And so the question I pose to you is have you looked at the changes in seismicity and as it assumed to exist now and concluded that that does not impinge on this plant providing adequate protection to the public health and safety.

MR. MANOLY: I don't believe -- I think there is another effort that was done. I can't recall when we discovered the new information of seismicity that addressed the plants on the east coast and I think that in NUREG CR which I can't remember the number, but that's really relevant to answer your question. But for the power uprate we don't revisit the seismic assumptions as long as they existed in the licensing basis to the plant. I mean your question is very relevant but I think that's addressed in a different exercise and I can get you more information on that.

MEMBER POWERS: I guess I'm fishing around to understand. I certainly am acutely aware of the changes of seismicity at sites Clinton, Grand Gulf and North Anna which kind of ring or form some sort of an arc across this plan. I am not aware of major changes in the seismicity at Browns Ferry. My suspension is that they're small but I don't know that for a fact.

MS. BROWN: Bill, did you want to add something?

MR. CROUCH: Yes. Remember as John says, the uprate itself doesn't change the seismic loads, but we have been reanalyzing Unit 1 for all the seismic loads as part of the restart and when we did that, we assumed the loads associated with the 120 percent uprate. So it's in the analysis using whatever equipment was added into the plant or replaced in the plant as part of the restart process.

MEMBER POWERS: What Im asking is as your seismic source term, what I'm effectively asking is if I build a new plant at this site would I change the seismic source term significantly from what you have in your FSAR for these plants recognizing things have happened in the last 20 years over what the perceived seismicity of the east coast is. In some cases, that's fairly dramatic. I suspect for your site it's not very dramatic, but I don't know that for a fact.

MR. CROUCH: I think it's --

MR. WU: Dr. Power, you have a good point. Regarding the seismics, the evaluation of the seismics, in the '80s, we have SEP, seismic evaluation program and in the '90s, we also looked at all this seismicity, look at all the seismic effects only if SECY related by we called it USI and result of SECY issue, USIA for instance. In that sense, we looked at all this SECY related equipment to make sure that all this SECY related equipment is ready for the shutdown. Yes, from there --

(Off the record comment.)

MR. WU: For the Unit 1 site. Unit 1 we just finished.

MR. MANOLY: It's the last plant we did USI 46 for. We had completed all the USI 46 in the '90s and Browns Ferry Unit 1 was the last plant that we did safety evaluation for, A46 implementation which was for qualification or seismic adequacy of plant equipment for safe shutdown. But that's still based on the assumptions of the original seismicity that the plant was licensed for and I want to answer your question.

MEMBER POWERS: What I'm telling you is that it's changed dramatically.

MR. MANOLY: Yes, I understand that. I understand what you're saying.

MEMBER POWERS: And so I'm asking the question. Does this plant still provide adequate protection to the public health and safety with respect to seismic?

MR. MANOLY: I think the comparisons for the change in seismicity, we have that, the staff has that and we can present that to you. But I just wanted to decouple from the power uprate.

MEMBER POWERS: Absolutely. This is outside of that discussion.

MS. BROWN: But the question you asked the staff is do we have reasonable assurance of the ability of these plants to operate uprated conditions given the seismicity that we're aware of it and I believe the answer to that is yes. We don't have any information that I'm aware of that suggests that we should change or alter that determination at this point. Should we receive additional information, we'll go ahead and take a look and then make an evaluation at that time.

MEMBER POWERS: I guess I would be happy to provide you information that says that the seismicity has changed.

MS. BROWN: Thank you sir.

MEMBER POWERS: What I don't know is whether it's changed significantly.

MS. BROWN: Thank you.

MEMBER SIEBER: But if that's the case, it's unlikely to affect just the uprate.

MS. BROWN: It would affect -- Yes sir.

MEMBER POWERS: -- turning the fan on in the morning.

MS. BROWN: Yes sir. We definitely -- If you have indication.

MEMBER ABDEL-KHALIK: Do any of the changes made at Unit 1 in components and/or piping have any impact on the limiting seismic loads?

MS. BROWN: I believe the first thing on our slide. Does that answer your question?

MEMBER ABDEL-KHALIK: So have you analyzed all the changes that have been made to Unit 1? In other words, it just gratuitously turned out to be the exactly the same as it was before.

MS. BROWN: Bill, would you like to comment?

MR. WU: It was different

MEMBER ABDEL-KHALIK: I mean the statement says "remain unchanged."

MS. BROWN: Go ahead.

MR. CUTSINGER: This is Rick Cutsinger, TVA Civil Engineering Manager. The analysis that we did for seismic is exactly the same methods and processes we used for Units 2 and 3. The criteria and the allowables are all the same and we maintained all the allowable stresses of all the components within our stated criteria.

MEMBER ABDEL-KHALIK: So did they analyze the changes in components and/or piping that had been made in preparation for getting this unit restarted have had no impact on the result of these analyses.

MEMBER ABDEL-KHALIK: The changes in piping and components were reanalyzed to make sure they were in compliance with our criteria.

MEMBER ABDEL-KHALIK: Okay. Thank you.

MR. WU: We have looked at the results hiding in the components regarding the stresses and cumulative for the uses factor. They are below the limits, all below the limits, which satisfies the code, all of them. So that means it's adequate.

MS. BROWN: And the information that we sort of went over also staff found applicable for the NSSS and the balance of plant piping. What we're saying is that the limiting size of loads remain unchanged. The most limiting LOCA dynamic loads remain bounding. The calculated stresses and accumulative fatigue usage factors were less than the code allowable limits and there is also the consideration because this added confidence at least when we're talking about Unit 1 that Units 2 and 3 have successfully operated 105 percent power since 1998 without incident.

When we looked at the seismic and dynamic qualification of equipment, the staff also found no change in the seismic loads, no new pipe break locations or pipe whip and jet impingement targets, no increase in pipe whip and jet impingement loads and no increase in the SRV and LOCA dynamic loads. As a result the staff found the seismic and dynamic qualification remain acceptable.

All right. I know you've been waiting for this. The staff is aware that there has been a lot of discussion regarding the status of the steam dryer review. The Licensee has indicated to the staff that

Unit 1 steam dryer and steam system design is similar to that of Units 2 and 3 and has been modified to be more robust and stronger than the Units 2 and 3 and that those units have operated 105 percent since the late '90s without evidence of dryer cracking. The staff feels that these facts provide reasonable assurance that Unit 1 should be able to operate at 105 percent.

CHAIRMAN BONACA: The SER says that in fact Units 2 and 3 developed cracks.

MS. BROWN: Yes sir.

CHAIRMAN BONACA: And that they had certain repairs that you have now implemented on Unit 1. So I mean why do you say there were no cracks?

MS. BROWN: Yes sir. I believe Bill discussed that a little bit yesterday what the issues were with that cracking. Bill or --

MR. VALENTE: This is Joe Valente. The crack, Dr. Bonaca, was associated with IGSCC, the material and a slightly undersized weld. It occurred on both the previous Units 2 and 3. We did have indication of a crack on Unit 1, same weld, same size weld. So that repair has been made on the Unit 1 dryer.

CHAIRMAN BONACA: If I remember you made

two modifications to the Unit 1 dryer.

MR. VALENTE: Yes, and we changed out tie bars and the cover plate.

CHAIRMAN BONACA: I remember.

MR. VALENTE: And outer hood fix.

MEMBER SIEBER: Wear type dryer. Right?

MR. VALENTE: Slant hood type.

MEMBER SIEBER: Slant hood, okay.

CHAIRMAN BONACA: Okay.

MS. BROWN: However, the staff is keenly aware that small changes in configuration have the potential to result in much different acoustic effects. As a result, TVA will monitor the Unit 1 main steam pressure fluctuation of vibrations and conduct walkdowns during power ascensions.

MEMBER WALLIS: What kind of vibrations are going to be monitored?

MS. BROWN: Bill, did you want to field this?

MR. VALENTE: Joe Valente again. Dr. Wallis, what we're going to do is put on the strain gauges to monitor the change in the main steam lines.

MEMBER WALLIS: Main steam lines.

MR. VALENTE: Main steam lines to get the pressure fluctuations to project back on to the dryer hood. In addition to that, we're going to monitoring recirc pipe, feedwater pipe.

MEMBER WALLIS: So you're using strain gauges to get the pressure fluctuations. You're not measuring the pressure fluctuations directly.

MR. VALENTE: No. Now --

MR. WU: You also indicated in one of the responses piping vibration will be monitored with the remote sensors, cameras or instruments. Also there are some extra meters will be installed and I think that in one of the slides we also indicate that the Unit 1 steam dryer -- Let's see. Where extra meters or measurements, okay, power sensory procedures. The steam typing acceleration measures every 2.5 percent. In other words, there will be extra meters installed on the main steam dryer.

MEMBER WALLIS: It's not pressure you're measuring directly. It says here pressure. It's actually the vibration of the pipe you're measuring or the stresses in the pipe.

MR. WU: The pressure --

MEMBER BANERJEE: It's the hoop stress. What are you actually -- Can you tell us what you're measuring?

MR. VALENTE: The hoop stress with the

strain gauges.

MEMBER BANERJEE: And are you putting in accelerometers as well?

MR. VALENTE: Yes. What John was alluding to, we are going to place accelerometers and some LDTDs on main steam, recirc and feedwater lines. In addition, our system engineers, A. E. Wells, will have the capability with hand-held instrument to measure vibration out in the plant on these lines and that's all in the plan for the power ascension for --

MEMBER WALLIS: So this is not really a true statement. You're measuring fluctuations and the stresses in the pipe wall and you're measuring the acceleration of the pipe wall.

MR. VALENTE: The pipe.

MEMBER WALLIS: You're not measuring steam pressure fluctuation.

MR. VALENTE: No.

MEMBER SIEBER: You said you had eight points where you could look. Where are those points at?

MEMBER BANERJEE: Do you have a diagram or something?

MR. VALENTE: Yes, we have a slide we can put up if Len can get his computer.

MEMBER CORRADINI: Swap computers.

MEMBER BANERJEE: And you're not instrumenting the dryers at all.

MR. VALENTE: No sir.

MEMBER BANERJEE: Now like what --

MR. VALENTE: No sir.

MEMBER WALLIS: And what's this walkdown tell you? You walk down and you say the pipe seems to making a noise or what is it you look for when you walk down this thing?

MR. VALENTE: We know what the plant behavior is on Units 2 and 3. We expect the same plant behavior on our balance of plant piping systems.

MEMBER WALLIS: You know what kind of a noise it makes when you walk beside it and when you up the power, the noise may change.

MR. VALENTE: That's correct.

MEMBER WALLIS: At that sort of level.

MEMBER ABDEL-KHALIK: What frequency ranges are we talking about here?

MS. BROWN: Isn't that one of our --

MR. VALENTE: The frequency range is fine.

MS. BROWN: It's okay.

MR. VALENTE: But let me go through the strain gauges first since we have the slide up. What we've done is on all four steam lines at two locations on each steam line laid an array of eight strain gauges to measure the differential -- On each steam line, we've been putting an array of eight strain gauges circumferentially around the pipe to measure the hoop stresses and from that hoop stress, we then develop a differential pressure that is then converted into a load that's generated back onto the steam dryer for analysis purposes.

MEMBER CORRADINI: And you do a computation to impress what the pressure is at that spacial location back to the dryer? Are you just using the same pressure?

MR. VALENTE: Yes. No, there's an analysis that's done. To get into the analysis aspect, we'll have to go into closed session because that's proprietary documentation.

MEMBER BANERJEE: Now some measurements of this nature are being made on Quad Cities --

MR. VALENTE: Yes.

MEMBER BANERJEE: -- which have coordinating, I suppose, hoop stresses with what's actually happening in the dryer.

MR. VALENTE: That's affirmative.

MEMBER BANERJEE: Are your dryers similar to Quad Cities or are they different?

MR. VALENTE: The Browns Ferry dryers are a slant hood construction. The original Quad Cities dryers were a vertical hood construction and the new --

MEMBER SIEBER: Square corners.

MR. VALENTE: Right. And the new Quad Cities dryers are, I guess, a slant in the perspective that it's a constant slope. It's a sloped hood.

MEMBER SIEBER: Later model.

MR. VALENTE: Later model, right. But the methodology was benchmarked against Quad Cities measure plant data and then adopted to the Browns Ferry's geometries.

MEMBER BANERJEE: Now I remember sitting at that session, so I'm not going to say anything which can't be said in open session. But I remember that there was very poor correlation between this model and what was seen in a scaled-down system that was used and what happened in Quad Cities. Is that a true statement or not?

MR. VALENTE: The GE scale model, that was a 1/17 scale model of the Quad Cities' dryer and certain frequency bands did not have good correlation. In other frequency bands, it did have good correlation and GE was trying to develop a subscale model to predict dynamic pressures within the steam dome as opposed to trying to -- You see it's very difficult to lay instrumentation on these existing dryers just because of radiation dose and things of that nature. So we, the industry, was trying to develop alternative ways to predict pressure on these steam dryers.

MEMBER BANERJEE: These dryers are new dryers, aren't they?

MR. VALENTE: No, our dryer has been -- It operated from 1973 --

MEMBER BANERJEE: New added batches and -- plates and all sorts of things to them.

MR. VALENTE: No, Units 2 and 3 dryers we had some cracks on the tie bars. The Unit 1 dryer, the original tie bars are still intact.

MEMBER SIEBER: Well, sure. You haven't run the plant.

MR. VALENTE: Yes, but the key point here, Jack, is, the key point here is, the damage to those tie bars we don't believe was operationally induced. It was due to the handling during refueling outage.

MEMBER SIEBER: It could be.

MR. VALENTE: Our original bars on Unit 1 are an inch by an inch by 3/16 inch thick.

MEMBER SIEBER: Well, my original question which we drifted away from had to do with the manual points that you had set up to make measurements. My question, I have several questions. One is where are they. The second question is what do you intend to measure. The third question is if you measure it manually you have to have a person there. The radiation dose is pretty high there. How are you going to deal with that?

MR. CROUCH: All these issues, these are strain gauges and the wires are taking that out of containment into a -- system.

MEMBER SIEBER: You glue them on and they're there.

MR. CROUCH: They're welded on. Right.

MEMBER SIEBER: Okay.

MEMBER ABDEL-KHALIK: Again, the question I posed earlier, what are the frequency ranges we're talking about?

MR. CROUCH: The frequency range that we're doing analysis for at Browns Ferry is zero to 250 Hz.

MEMBER BANERJEE: So when you did the --

MEMBER ABDEL-KHALIK: And where were these frequencies, you know, these dominant frequencies, how were they determined?

MR. CROUCH: We looked at the various acoustic sources we have in the steam line. We have two primary acoustic sources. One is the target rock valves that have -- They are the safety relief valves. They have a frequency of around 115 Hz. Then we have some blind phalanges that have no valves on them that have a resonance frequency of around 220 Hz. So that's why we did a range of zero to 250.

MEMBER SIEBER: I presume the dryer's vibrating would be lower than frequency. Right?

MR. CROUCH: The dryer has structural frequency resonances from starting around 9 Hz up to higher frequencies.

MEMBER SIEBER: Nine or ten. Which ones did you pick out? Especially when they're going to the turbines. Right?

MR. CROUCH: Correct.

MEMBER ABDEL-KHALIK: Have you completely excluded higher frequencies?

MR. CROUCH: Higher than the?

MEMBER ABDEL-KHALIK: Two hundred fifty Hz cut off.

MR. CROUCH: Yes.

MEMBER ABDEL-KHALIK: And how was that

exclusion decided upon?

MR. CROUCH: The wave length gets to become too short.

MR. BILANIN: Alan Bilanin from CDI. As frequencies get higher, the acoustic wave lengths get shorter. You start exciting higher and higher modes of the structure that don't effectively couple very well. So it's not thought, but it's well demonstrated that what you really need to do is make sure you get the primary loading on the structure and get the lowest modes of the structure and get that correct.

MR. PAPPONE: And this is Dan Pappone, GE. We do have some measurement data from instrumented dryers where we have put strain gauges on the dryers themselves and when we look at the measurements, we've taken their -- Like Allan said, the forcing functions are in the zero to 250 range and we don't see any real significant strain gauge response on the structure itself at higher frequencies.

MEMBER SIEBER: That means the amplitudes are small.

MR. PAPPONE: Right. That's right.

MEMBER BANERJEE: Before you go away, when you see these vibrations on the instrumented dryers, are they --

MEMBER CORRADINI: They don't see that.

MEMBER BANERJEE: No. Dan, General Electric. When you see these vibrations on the instrumented dryers, do you find a correlation of any sort with the downstream measurements?

MR. PAPPONE: Dan Pappone from GE again. Yes, we do. If you want to think of it as basically the approach that's being used, we're listening in on the steam lines using them as a stethoscope and we do see a good correlation between the fluctuating pressures that we're hearing in the steam lines and what we've measured on the dryer itself.

MEMBER BANERJEE: And are you using strain gauges to measure the fluctuations on the steam lines?

MR. PAPPONE: In these applications, every application we've done like this, we've had a ring of strain gauges at each measurement location so that we are measuring the hoop stress and then doing an analytic conversion to a fluctuating pressure from the hoop stress.

MEMBER BANERJEE: And this fluctuating pressure correlates at all frequencies or at some frequencies with what you see at the dryer?

MR. PAPPONE: We've seen a good correlation where we have an acoustic signature, something that we're listening to, and this idea, the standpipe resonance, the dead-like organ pipe branch resonance. We have a very good correlation throughout the system on that from the source through the piping and onto the dryer.

MEMBER BANERJEE: Do you have this documented? This results? No?

MEMBER CORRADINI: Can we look at this, I guess, is what --

MR. PAPPONE: Yes.

MEMBER BANERJEE: And these measurements were made on an operating reactor such as Quad Cities.

MR. PAPPONE: The Quad Cities' reactor after the issues that we had when GE put the replacement dryer in, we instrumented that dryer. We had an array of pressure sensors on the face and a few on the skirt and then we also had this steam line strain gauge pressure measurement system in place so that we could do that correlation and benchmark the analytic models that we're using.

MEMBER BANERJEE: And since you've put this on, have you seen any damage at all or is you've just been correlating the vibrations?

MR. PAPPONE: The primary purpose of what we're doing in these measurements is to develop the load definition that we're using for the structural analysis on the dryer and so we're in a mode where say in Browns Ferry what we're doing now is we took measurements there, developed that load definition. We're doing structural analysis and then during the power ascension we'll take measurements again to confirm that we've predicted as a load that we're not seeing any surprises there and we're staying within the analysis basis.

MEMBER BANERJEE: If I understand you correctly then, what you're really saying is that the loads on the dryer are primarily some sort of standing acoustic or some sort of an acoustic wave and it's not a local vortex shedding phenomena. Is that correct?

MR. PAPPONE: There are two basic loads that we're seeing on the dryer. One is the acoustic load that's generated outside and then there is, I believe, a local vortex at the entrance to the steam line that's also providing a load and we do see that signature in the steam line.

MEMBER BANERJEE: So there is nothing that you don't see in the steam line that's giving you a big load that you know of right now.

MR. PAPPONE: That we know of.

MEMBER ABDEL-KHALIK: Did you plan to

confirm these dominant frequencies by doing an FFT on the strain gauge signal?

MR. PAPPONE: Yes, that's part of the process. Actually, the -- Yes, the load definition calculations are being performed in the frequency domain.

MEMBER CORRADINI: Can I ask another question because I'm curious about the analysis to the extent? But the document has this analysis that we're asking about that we can understand better. Let me tell you where I'm going with this. What you're saying is that I have a certain three dimensional structure in Quad Cities that you're measuring stuff on that structure and then you're measuring it downstream and you're seeing a correlation. But if it's a three dimensional structure and it has a natural frequency, I would assume it's the natural frequency of the structure and how it interplays with what's reverberating.

So my next question is let's say all the fluid mechanics is identically the same. Is the fundamental natural frequency of the structure different so that it would play differently with a different physical structure?

MR. PAPPONE: Basically, we're not seeing

-- If you're getting into, say, the fluid structure interaction, we're not seeing a significant fluid structure interaction like a flood or anything like that and as part of the Quad Cities' analyses we went through, we also had strain gauges at key locations on the structure. We took the -- We had measurements there, took the steam line pressure measurements, ran them through, developed load definition, put that onto a finite element model of the dryer and then predicted the strains at the locations where we had the strain gauges and put the plots next to each other and we got a good correlation there.

MEMBER CORRADINI: Assuming that the structure is rigid versus that it is essentially somewhat pliable relative to the pressures you're applying, is that what I just heard?

MR. PAPPONE: We're assuming that we're not getting a significant fluid structure interaction such that the vibration of the structure is affecting the load definition.

MEMBER BANERJEE: I guess -- Let me --

MR. PAPPONE: But again, we have a good correlation. We have a good agreement between the predicted strains at those locations on the dryer and what we measured at those locations and that helps confirm that.

MEMBER CORRADINI: So may I ask one last question and let Sanjoy go back to it. So what you're saying is that from your analysis the structure is essentially infinitely rigid and it's the -- There's no feedback and there's essentially the pressure due to whatever mechanism is the fluctuating pressure which is causing local strains and stresses that then is the root cause of any cracking versus the structure itself being pliable and feeding back and getting to some harmonic and it's sitting there singing in the breeze. I'm trying to get to a root cause.

MR. PAPPONE: Okay.

MEMBER CORRADINI: I'm trying to understand.

MR. BILANIN: We don't believe there's a air elastic instability of the dryer. The energy that --

MEMBER SIEBER: I can't hear you.

MR. BILANIN: There is no evidence of an air elastic instability of the dryer. It looks like the source that are across the acoustics are looked located downstream, the primary one downstream in the main steam lines. That sends an acoustic wave upstream, standing wave. That's standing wave bangs in perpetuity on the dryer and causes the fatigue to occur.

MEMBER CORRADINI: Thank you.

MEMBER SIEBER: That presumes then that the diameter of the steam line has a major impact on the frequency and the amplitude of that wave. Is that correct?

MR. BILANIN: The diameter of the steam line does and I'm actually glad you brought that point up. My name again, Alan Bilanin, Continuing Dynamics. Thomas Edison observed when he was looking at developing a device that if in fact you taper a tube and use it in your ear you can amplify sound.

MEMBER SIEBER: Yes, I need one of those.

MR. BILANIN: If you're looking at acoustics -- Okay.

(Laughter.)

MR. BILANIN: So it's not a bad idea where in fact the flow is converging down to a narrow tube in your main steam lines to put your pressure transducers there and measure acoustics there and infer back what's going on on the dryer. So that's the basis of the analysis that's done and you find out that the dominant loads on the dryer are in fact acoustic in nature and then subscale testing and other testing is confirmed with the sources, where the sources are, and they seem to be a whistling phenomena in some of the stand pipes in the main steam lines as one of the dominant sources.

MEMBER SIEBER: And so one could perhaps not draw a conclusion but get a better or worse feeling if one would compare the diameter of the steam lines at Browns Ferry with the diameter of the steam lines at some Illinois plant.

MR. BILANIN: Yes. One could do that but then the other, more dominant effect is what's the diameter of the inlets to the stand pipes, so the Coke bottles that are fastened along the main steam line and how they whistle and what frequency they whistle and that is quite different between plants.

MEMBER SIEBER: Could you give me any insights as to what those differences in designs are?

MR. BILANIN: Oh, some of the diameters in lines are four inches up to six or eight inches for the inlets to the main steam lines and several valves or one or two valves per line 'till have five or six of them on a line and then the distances that are between each other unfortunately sometimes comes out to be exactly a wave length of the resident frequency. So these plants are complicated musical instruments and very expensive musical instruments and there wasn't a design criteria when the stand pipes were placed for the safety valves that are mounted on top of them. Some of them could have been located in better locations.

MEMBER SIEBER: My guess is that an attempt to develop a scale model that would reproduce these phenomenon would be next to impossible.

MR. BILANIN: We don't believe it so. We've had some success at fifth and eighth scale doing that.

MEMBER SIEBER: You have a lot of things that scale different ways. Do you know what I mean?

MR. BILANIN: We've been successful if you look strictly at the acoustics and the onset to go ahead and come up with loads from fifth and eighth scale testing.

MEMBER SIEBER: Thank you.

MEMBER BANERJEE: I want to continue this. Dan, don't sit down.

(Laughter.)

MEMBER BANERJEE: If what is being proposed, the hypothesis, is true, then the equations which govern this phenomena, just the wave equations, you have a Foxfillian sort of expression for this. So why is it now possible simply to calculate these things if this hypothesis is true? There's no Navier-Stokes involved.

(Off the record discussion.)

MR. BILANIN: Because the mean flow being converted into oscillatory unsteady energy is occurring in this sheer layer that flows over the inlet to the inlets to the stand pipes. So it's a very nonlinear, very complicated --

MEMBER BANERJEE: That's the source term. Right?

MR. BILANIN: That's exactly right and you're saying let's compute the source. If you can compute the source, then you can calculate the radiation. So we don't compute the source. What you do is you measure the pressure field that has radiated from the source and project the pressure field back onto the dryer. That's a lot easier problem.

MEMBER CORRADINI: Measure the radiated field?

MR. BILANIN: And then project the radiated field out onto the dryer. You never compute the source.

MEMBER BANERJEE: So it's an inverse problem you're trying to solve.

MR. BILANIN: Yes.

MEMBER BANERJEE: Well, but have you actually set up the radiation field in some sort of Foxfillian type of a set of equations and looked at what the source terms will do? I mean do the forward problem.

MR. BILANIN: The methodology -- We haven't done that, but the methodology is available in a proprietary report.

MEMBER BANERJEE: Well, yes. NASA has this. I mean almost everybody does this. So I'm just wondering why the hypothesis can't be directly tested.

MR. BILANIN: We think it has if in fact you take a look at the correlations with the Quad Cities' data. There in fact were eight pressure measurements on four steam lines and 26 pressure measurements on the dryer itself and then strain gauges and accelerometers on the dryers. So it answers the question of what part of the pressure field measured on the dryer is acoustic. Is that more significant at a given frequency? It asks the question of taking that load that computed, putting it through a finite element model and predicting stresses. It tells you whether a fluid structural interaction is coming into play and looking at the acceleration that are measured on the dryer as well. It confirms again whether fluid structural interaction is contributing to the pressure fields that are measured on the dryer as well. So there is a dataset that is very comprehensive that this model has been rung out again.

MEMBER BANERJEE: I'm more against trying to see if there's an predictive power to this model. So what -- Or any -- We know that the equations really govern this model. It's not like it's something unique. You have lots of solvers which do this. Really what I'm after is to understand does it have predictive power so that you will be able to say what will happen in Browns Ferry before the measurements.

MR. BILANIN: At a higher power level.

MEMBER BANERJEE: Yes.

MR. BILANIN: No. The answer is it doesn't. It doesn't do that. It listens in on the main steam lines and hears pressure fluctuations and tells you what the loadings are on the dryer at that power level.

MEMBER BANERJEE: But if the model is predictive, it should be able to tell you.

MR. BILANIN: It's not a predictive model. The sources have to be there radiating that sound in those main steam lines. You measure that pressure field and then you move it onto the dryer. So the plant has to be operating at the power level that you want the load on the dryer.

MEMBER BANERJEE: Measurement.

MEMBER CORRADINI: So might I ask the -- Maybe you're not the right person to ask, but might I ask this back to the staff? So the protocol is let's say that's all right and now you're at 105 and you want to go to 110. What's the protocol that you're going to do then to essentially make the extrapolation to the next five percent?

MS. BROWN: Okay.

MEMBER CORRADINI: That's what I'm --

MS. BROWN: It's actually on the slide.

MEMBER CORRADINI: Thank you.

MS. BROWN: Thank you very much. We can get back to where I am.

MEMBER ARMIJO: Are you going to answer that question?

MEMBER CORRADINI: I didn't mean to divert you guys from anything, but by answering that, I'm now --

MS. BROWN: I don't think we ever answered your question.

MEMBER CORRADINI: -- I mean if you're taking the approach that you don't want to make a predictive, you want to make an empirically valid one.

MEMBER BANERJEE: No, I would prefer it to be predictive.

MEMBER CORRADINI: I understand.

MEMBER BANERJEE: They're saying --

MEMBER CORRADINI: They won't or they can't.

MEMBER BANERJEE: -- they can't.

MEMBER CORRADINI: I don't understand how you get that next five percent logically.

MS. BROWN: Tom, did you want to go through --

MR. SCARBROUGH: Right. Well, this whole discussion is basically the reason why we're here today on 105 because they came in with 120 request over the summer and indicated that based on their analysis using the 1/17th scale model they were predicting some of their components in their steam dryer would have potential problems and we saw that and we agree with that. They went back and did some further analysis. They came back and said, "Okay, now we think we're okay with these levels of stress in the components in the steam dryer."

Based on all of the uncertainties that you've just been talking about, the staff was unable to agree that we were comfortable with them going to 120 power. The uncertainties in the analysis, extrapolating this information, the nature of it, all of these factors led us to a decision that the assumptions in the analysis, the uncertainties in the scale model, all of that, we weren't ready to try to prepare a safety evaluation accepting to go to 120.

TVA went back, relooked at our concerns. We sent out a long list of requests for information with specific concerns that we had, damping assumptions, things of that nature and they came back and they said, "Okay. Because we don't have any plant-specific data" and that was part of the problem, the significant problem with here, Vermont Yankee had plant-specific data. Quad Cities had plant-specific data to try to see what those pressure fluctuations were in the plant. They did not have that here at Browns Ferry at any of the units at that time and when you don't have that you don't have a way to really correlated what's happening in the scale model with what's happening in the real plant.

So with that, we were sort of flying blind. We were sort of relying on the scale model to tell us exactly what's happening in the plant. And each plant as you've talked about is different. With that, TVA said, "Okay. We will do that. We'll ask for 105 percent. We'll take Unit 1 up to 105. We'll get the plant-specific data at 105 from the steam lines, use that to correlate what's happening in the scale model" and things of that nature. That's one way to do it.

Vermont Yankee as you all remember did not have -- did not use the scale model at all. They started with the assumption. They used plant-specific data, measured what the pressure fluctuations were by monitoring the strain gauges to see what level of noise was happening in their plant. From that, they calculated what the stresses were on the dryer through this analysis that Alan Bilanin was talking about.

Then from that, they said, "Okay. That's how far we are away from the stress limit of the dryer. We will think that this uncertainty, this analysis, is about 100 percent uncertainty which is probably about what we thought." So they increased it because they did a frequency-specific uncertainty analysis based on information from Quad Cities where they actually had an instrumented dryer and they compared it to the analysis coming from the steam lines and they said, "Okay. If you look at it on a frequency-specific basis over discrete intervals, there are places where it's pretty conservative, places where it's not." So they tried to take the worst case and said, "Okay. This is the way it could be in terms of the frequency ranges of interest."

MEMBER BANERJEE: Where are they now in this process?

MR. SCARBROUGH: Vermont Yankee? They're up and running at 120 percent power. What they did, they went back and developed power ascension limit curves where they said, "Okay. Assuming this is 100 percent uncertainty, uncertain, we will develop this curve which still keeps us like a factor of five or so below what a damaging stress level would be to 13,600 psi."

So they came up with that and then they started the plant up and using this type of power ascension process where they would go up at a small amount of time, measure the strain gauges, recalculate it and see what's happening with those strain gauge fluctuations and if they saw a pressure fluctuation, a resonance peak of any particular frequency that popped up and they had that. As they started the plant up, they started to see some resonances start to occur. They would come and go. And if they came up high enough to hit their power ascension curve, they would stop as part of the limit licensing condition on the plant. They would stop, reanalyze, run through the whole acoustic analysis again, see where they were in terms of the over because what the license condition was was any frequency peak that hit the curve they had to stop. It could happen. You'll have one peak at one particular frequency resonance pop up and hit. But all the others stayed down low. So overall, their energy is relatively low. But it required them to stop and reanalyze.

And that's what we did and over time, Vermont Yankee worked their way up to 120 percent power and I think they had to stop like three times where they popped up enough to hit that resonance. The rest of the times they have every five percent of power increase they had to stop and completely re-analyze and go up and that's what they did. It was over a couple of week time period it took them to work their way up to 120 percent power.

Now for Browns Ferry, we're only talking about 105 percent because what they need to do is get up to 105 percent, gather the data from the strain gauges, go back, decide how they're going to evaluate

120. They could go back, use that information to benchmark their scale model. That's one way they could do it. There are different scale models out there they could choose. They could go the path that Vermont Yankee did where they did not use a scale model and they worked their way down from an ultimate stress limit and do it that way and come in. But they haven't done that yet. So we're not in any position to say what they're going to do until they decide.

MEMBER BANERJEE: How different was the Vermont Yankee dryer from Quad Cities in design? Was it similar? I don't recall now.

MR. WU: Vermont Yankee is --

MR. SCARBROUGH: Well, in terms of --

MEMBER BANERJEE: Geometry.

MR. SCARBROUGH: The original dryers were square. Both of them were square.

MR. WU: Vermont Yankee still uses that.

MR. SCARBROUGH: Vermont Yankee and Quad.

MR. WU: They still use the square.

MR. SCARBROUGH: Yes, they use the square. Now Quad Cities, once they had the repeated failures of their dryer, they redesigned their entire dryer and made it taller, much thicker and bulkier and installed that and put pressure sensors, strain gauges, on the dryer itself and they used that to correlated what the main steam line strain gauge measurements were and the acoustic circuit model that they were using to correlate that back up and they used that and that's part of what Vermont Yankee did in terms of coming up with an estimate of what the uncertainties were.

MEMBER BANERJEE: But their dryers were geometrically similar or different?

MR. SCARBROUGH: For which plants?

MEMBER BANERJEE: Compared to Quad Cities.

MR. SCARBROUGH: Vermont Yankee?

MEMBER BANERJEE: Yes.

MR. SCARBROUGH: No, because once Quad Cities changed theirs, they went from a square design to a very tall, slanted --

MEMBER WALLIS: They went to the new GE design which is very much different, very much heavier.

MR. SCARBROUGH: Yes. It's much heavier and bulkier and now Vermont Yankee, they kept the same basic design but they beefed it up with much thicker plates and such to make it stronger.

MEMBER SIEBER: Right.

MR. SCARBROUGH: So they did that. That's how they did theirs. Now different, when you look at the data in the steam lines for both plants, there was significant difference in the acoustic resonance in the noise thumps. Quad Cities had significant pressure pulses going on in their steam lines, severe pulses. Vermont Yankee very quiet. If you look at the strain gauges for the steam lines, very quiet, and that's how they were able to work their way through this problem at Vermont Yankee is it stayed quiet. And as they started up the plant going to 120 percent, it still stayed relatively quiet. It came up a little bit but not much. So that's how they were able to handle it, whereas in Quad Cities 1 and 2, both of them had high pressure peaks in their steam lines, Quad 2 higher than Quad 1, but still both of them very high.

MEMBER BANERJEE: Once they changed the dryer, did these peaks stay the same or did they change?

MR. SCARBROUGH: For Quad Cities --

MEMBER BANERJEE: Yes.

MR. SCARBROUGH: -- the peaks still stay high.

MEMBER BANERJEE: And they stayed similar in shape and everything.

MR. SCARBROUGH: Right, because it was all steam line phenomenon. There were probably some small changes, but --

MEMBER SIEBER: Right.

MR. SCARBROUGH: -- from the design of the dryer.

MEMBER SIEBER: I agree with that.

MR. SCARBROUGH: But down the road since then, Quad Cities ended up having electromagnetic relief valve failures from this severe resonance in the steam lines and we had, the staff had, still not accepted the Quad Cities' new dryers in terms of long-term EPU operation because of this continuing concern about these high pressure fluctuations. After the electromagnetic relief valve failures at Quad Cities in Christmas time of 2005, Exelon went back and installed what they called acoustic side branches which are modifications in those steam lines, these branch lines we talked about, which resulted in the reduction of those pressure fluctuations down to where it's below the original licensing power fluctuations. So they are much lower.

(Off the record discussion.)

MEMBER BANERJEE: Let me ask you a question now that all this leads up to. You look at the Browns Ferry lines. Are they similar to Quad

Cities or are they very different? What do you expect of the fluctuations there?

MR. SCARBROUGH: Do you mean at Browns Ferry and Quad Cities?

MEMBER BANERJEE: Yes. I mean if you were --

MR. SCARBROUGH: I don't have a comparison of the two.

MEMBER BANERJEE: I mean would you expect the acoustic fluctuations based on the geometry?

MR. WU: We saw acoustic fluctuation on these at Browns Ferry --

MR. SCARBROUGH: The scale model --

MR. WU: -- the subscale model --

MR. SCARBROUGH: The scale model for Browns Ferry showed some high pressure fluctuations.

MR. WU: The scale model --

MR. SCARBROUGH: You know, this is the scale model. So you have to take it with a grain of salt.

MEMBER BANERJEE: Right.

MR. SCARBROUGH: It showed high levels of pressure (Coughing) like Quad Cities was showing. So that was one reason why we had some concerns is that it didn't look like -- the scale model was not showing a quiet Browns Ferry. It was showing a Browns Ferry more on the order of a Quad Cities.

MEMBER BANERJEE: Okay. Thank you. I think you've answered my question.

MEMBER ARMIJO: Tom, could I ask -- I have to change the subject a little bit.

MR. SCARBROUGH: Okay.

MEMBER ARMIJO: You reported that there was IGSCC in the dryers of Units 2 and 3 and I'd like to know why isn't that a matter of concern as far as Unit 1. I mean it doesn't matter whether it cracks from fatigue or cracks from IGSCC and if IGSCC can happen either before the 105 percent power uprate or after the 105 percent power uprate, it's still a mechanism for failure. So what's your reasoning or what's your expectation as far as integrity of the dryer with respect to stress corrosion cracking?

MR. SCARBROUGH: What we found is all of the steam dryers have some limited amount of IGSCC and when they discover it, they have to go back and evaluate the consequences of it, the extent of it and it's part of the normal process for maintenance of the steam dryers, where they're going, and looking at that aspect when they do inspections and that's part of what is done during the refueling actions.

MEMBER ARMIJO: I understand that, but what makes you think it isn't going to be worse with a higher power operation? More liquid phase will get into the steam dryer. More transient oxidizing species will be in that liquid phase perhaps and perhaps the environment for stress corrosion cracking is going to get worse and you have a lot of welds in there and is that a mechanism that the staff is satisfied is not going to be much of a problem or TVA or it hasn't been looked at.

MR. SCARBROUGH: Part of all of the other power uprates that we've had, there is some IGSCC that's discovered when they go and they look at it. We haven't see that to be a consequence and when you look at the failures that did occur at Quad Cities and the limited amount at Dresden and at some other places where they've had some smaller cracks, the IGSCC has not been part of the catastrophic type failure that's occurred at Quad Cities. It's been smaller cracks that grow, that we discover during --

MEMBER ARMIJO: Welds separating.

MR. SCARBROUGH: Yes, little things that don't cause a major problem that this acoustic resonance seems to be causing. So it is monitored and those types of questions are the types of questions we ask them when they find these types of IGSCC. Could be a trigger for something more? But that's something that they have to monitor as part of the -- The BWR in this group has an inspection program for the dryers and for the plants going up to power uprate and they have to monitor that. So we do. We do ask those types questions and that's is something we do look into. But so far, our experience has been that we haven't seen that to be a real trigger for any sort of catastrophic problems that occurred like at Quad Cities.

MEMBER ARMIJO: Okay.

MEMBER ABDEL-KHALIK: Are there any other potential sources of pressure fluctuations within the zero to 250 Hz range other than the whistling phenomena that was referred to earlier?

MR. SCARBROUGH: There have been -- Part of the monitoring is done in the steam lines to look for anything that's being transmitted back up through. Also as they're monitoring, when they do the monitoring with accelerometers, part of looking at the FFT for those to look at those frequencies to see what are the frequency peaks in there and what are the sources of those and that's part of what the staff discusses with the licensees like Vermont Yankee. As they go from power, we get those traces and they do to and you look at those FFTs to see, okay, these are the peaks. Where are those peaks coming from? What are the sources of them?

But there are situations where you can have inside the dryer itself, I mean, inside the rack, the dome itself, being its own mechanism to initiate and part of the discussion is to look for those. Can you see something that may be occurring that might be significant that could not be picked up by the dual strain gauges in the seam lines and part of that overlap is to look for the accelerometers, to look for that, to see if there's anything popping up from those particular frequencies spectra that might indicate there may be a source that wasn't being identified.

But so far, we haven't seen anything from the scale models or from the testing at Quad Cities or for the measurements on Quad Cities itself on the dryer because we measured actually on the dryer itself at Quad Cities for the new dryer. We haven't seen anything that wasn't being picked up that was significant.

MEMBER BANERJEE: May I just ask you a question? When you look at the fluctuations on the dryer and in the line, if you look at a phase lag, you do a coherence function, do you find that the dryer lags the line? You have a cross correlation, right, of these two signals?

MR. SCARBROUGH: Right.

MEMBER BANERJEE: So if you do a coherence and a phase lag, does that dryer lag the line fluctuations or does it proceed them? You would expect by your theory that they should lag them.

MR. SCARBROUGH: Right.

MS. BROWN: Dr. Bilanin, did you want to answer that?

MR. BILANIN: Alan Bilanin of Continuing Dynamics. The source is downstream. It's a harmonic source. It's a standing wave.

MEMBER BANERJEE: Right, but you get a coherence function. Right?

MR. BILANIN: Yes, it's highly coherent. It's highly coherent, but the phasing is such that you have a standing wave sitting there. So it's vibrating. There are actually pressure nodes and loops in the main steam line, pressure nodes and loops on the dryer. It's a standing wave. It's a forced vibration problem. It's forced vibration.

MEMBER BANERJEE: But they are not vibrating simultaneously. There's an acoustic wave moving. Right?

MR. BILANIN: Well, there's a wave going upstream and it's bounced back off the dryer and it comes back again. It operates for a long period of time eventually to steady state oscillation. There's a steady state source in the steam line generating steady state acoustic oscillations. Harmonic. It's a standing wave. Right.

MEMBER SIEBER: Okay.

MEMBER ABDEL-KHALIK: If I --

MEMBER WALLIS: Go ahead. Sorry.

MEMBER ABDEL-KHALIK: If I may go back to other potential sources of pressure fluctuations within -- This is a very wide range, zero to 250 Hz. So for example, coupled neutronic thermal hydraulic oscillations below the trip set point of the OPRM would certainly fall within this range. Would you be able to detect it with the transducers or the strain gauges on the steam line?

MR. SCARBROUGH: My understanding that down into the 20, 30 Hz range they're pretty good. Now down below that, there are discussions of how far apart you place the sensors and such and how reliable they are at the very, very low frequencies and that is one area that is continuing. It is an aspect of the model that's being used right now that could be stronger if there's a way to develop, you know, amplify that, try to make that a stronger aspect of the model. So we do look at that area.

We haven't seen anything from the work at Quad Cities where they did actually measure it. There wasn't enough there to say that there would be a severe problem with that lower frequency that might be occurring. But that is an area that there is some work going on. Actually, Exelon as part of their long range operation of Quad Cities is going to be monitoring the reactor pressure level instrumentation. They put additional sensors and instrumentation there to make it more precise to be able to look for very low Hertz types of frequency ranges which is something that may be occurring that wouldn't be picked up on those strain gauges. So that's an ongoing effort that they're looking at there.

MEMBER ABDEL-KHALIK: So right now, you say that the system's capabilities in the low frequency range is sort of questionable.

MR. SCARBROUGH: Right.

MS. BROWN: All right. I think that pretty much wraps up where we are.

CHAIRMAN BONACA: Tell us, include what

you're handling 105 power now. You know you're talking about that now.

MS. BROWN: Yes. Right now, the staff is in discussions with TVA on the type of monitoring they're going to be doing at 105. Primarily we're just discussing the time frame for which they will be providing information and the staff may be imposing a license condition to get that information but I believe TVA has said that they would give it to us. So we may not -- So you don't see that in the SE, but the staff was considering a license condition. But whether or not it remains a commitment or goes to a license condition is something we'll discuss with our legal staff.

For steam dryers, that's it unless there are any other questions.

CHAIRMAN BONACA: Okay. Then let's move to the -- maybe pumps and safety valves.

MS. BROWN: Yes sir. Do you want to hit that real quick.

MEMBER BANERJEE: We are going to revisit the steam dryer thing.

MR. SCARBROUGH: Absolutely for 120 percent.

MS. BROWN: This is specifically the March meeting. Yes sir.

The staff's review included certain safety related pumps and valves typically designated as Class 1, 2 or 3 under Section 3 of the ASME Code and within the scope of the Section 11 of the ASME O&M Code as applicable. The staff's review also focused on the effects of the uprates on the required functional performance of the valves and pumps any impacts that the proposed uprates may have on the MOV programs related to Generic Letters 8910, 9605 and 9507 as well as the Licensee consideration of the lessons learned from the MOV program and the application of those lessons learned to other safety-related power operated valves.

For the safety-related valves and pumps, the Code of record is the 1995 Edition to the 1996 Addenda of the ASME O&M Code. The Inservice Test Program assesses the operational erosion of pumps and valves. The scope and the testing frequencies will not be affected by power uprate. No changes in the Inservice Test Program in support of the power uprate requests are anticipated with the exception of specific implementing procedures.

TVA stated that many design changes were being prepared to uprate or replace Unit 1 motor operated valves to support uprate operation and response to Generic Letters 8910 and 9507. For example, TVA stated that 17 MOVs will be entirely replaced, 34 actuators will be replaced and the Licensee's goal was to have all 8910 MOVs with SmartStems installed to facilitate diagnostic testing. Generic Letter 8910 at Unit 1 will be tested as part of the post MOD program before being declared operable and for the Generic Letter 9507 pressure locking and thermal bonding concerns, the safety-related power operated gate valves, one HPCI and two Core Spray flow valves will have double disk valves installed before restart.

TVA also indicated that five HPCI and Core Spray valves will drilled with a hole in the reactor disk side to preclude the potential for pressure locking. TVA has also reiterated their intent to implement the Joint Owners Group Program in response to Generic Letter 9605.

CHAIRMAN BONACA: The previous slide said "of the Inservice Testing Program's scope and frequencies not affected by power uprate." I imagine this is a problem that is already in place at Units 2 and 3 and is being moved to Unit 1.

MS. BROWN: Yes sir.

CHAIRMAN BONACA: And so there has been an evaluation of the applicability?

MS. BROWN: Yes sir. We're going to -- I'm going to get to that.

CHAIRMAN BONACA: Okay.

MS. BROWN: Let's go past the acceptance criteria and go straight to the special items.

The Units 2 and 3 review in this area was more routine in that there were no effects expected for safety related pumps and valves as a result of power uprate and the associated generic communication programs have previously been reviewed and due to no EPU effects remain acceptable. However, at the time of the staff's review, not all the items necessary to close out the Generic Letter items had been completed.

The previous slides outline some of the actions needed to close the MOV program and the staff therefore conducted an inspection November of last year which found that on Unit 1 the Licensee had a well developed program with a reasonable design assumption and operating experience. There was more work needed to complete the MOV testing and feedback results to confirm some design assumptions, but the staff's walkdowns found that MOVs ready for operation and in good condition. As mentioned previously, the long-term Generic Letter 9605 program follows the Joint Owner's Group recommendations.

Did that hit on your --

MR. SCARBROUGH: I just have one clarification. Just on that because I hadn't noticed, they're in the process of taking system by system and getting them ready for operation. So the ones that were ready were all in good operation, good condition. But there are some that are still in the process of being ready for operation. So those would be the ones that still have some work to go on them. But the ones that had been completed were ready to go, were in good condition and we inspected those.

We inspected about 30 out of the 51 MOVs in the program and they were in good condition, quite a bit of work on them and they're still working on other systems. They were just doing the HPCI system, I think, whenever I was there.

MS. BROWN: The process parameter and ambient temperature increases seen during operation of uprated conditions were found to require no significant changes to the functional requirements of the safety related valves. The existing Generic Letters 8910, 9507 and 96 programs were found to remain adequate at uprated conditions. Therefore, the staff found that the operation of safety-related pumps and valves acceptable for extended power uprate conditions and acceptable and bounding for the Unit 1 105 percent uprate.

Was there anything else on valves or pumps?

CHAIRMAN BONACA: No. Following your comment regarding there are still certain portions that are being inspected, I would like to hear from TVA. What's the plan for restarting Unit 1? I think as they're shifting and moving and I am confused about timing and I understand things may still change. But could you give us a little brief update on what the plan is for Unit 1?

PARTICIPANT: We'll get the VP, Ashok Bhatnagar.

MS. BROWN: Dr. Bonaca, I can tell you what they've told the staff or what the staff's understanding is of their restart schedule.

CHAIRMAN BONACA: As of?

MS. BROWN: As of the 10th of January.

MEMBER CORRADINI: That's pretty recent.

MS. BROWN: Yes sir.

CHAIRMAN BONACA: Well, nothing that would --

MEMBER SIEBER: Good enough for now.

CHAIRMAN BONACA: Okay. Go ahead.

MS. BROWN: I know you said it and I just forgot what it was. Actually, I really did.

MEMBER POWERS: Can't it wait?

PARTICIPANT: Ashok will be here shortly.

MS. BROWN: Okay. I will defer. But why don't we go through and hit --

CHAIRMAN BONACA: Let's go through the presentation and then when the Chancellor comes we will ask him.

MS. BROWN: It's very quick and just a couple more.

CHAIRMAN BONACA: All right. Let's go. Mr. Bhatnagar, would you like to --

MR. BHATNAGAR: My name is Ashok Bhatnagar. I'm Senior Vice President of Nuclear Operations. I'm sorry I was out. So I didn't hear the question.

CHAIRMAN BONACA: The question is what's the plan for the restart of Unit 1. I mean there's been some changes. We go from 20 percent power uprate to 5 percent.

MR. BHATNAGAR: That's correct.

CHAIRMAN BONACA: -- intend to go into

February. Now I understand it's been delayed. I'm trying to understand what your plan is regarding -- And we understand also that there might still be changes.

MR. BHATNAGAR: Correct.

CHAIRMAN BONACA: But for now?

MR. BHATNAGAR: Let me try to cover that. We've made significant enough progress on the reactor building and drywell as far as the modifications that were done there. We took the opportunity to move up the Unit 2 refueling outage. Unit 2 is already in its coast-down period and we looked out into the future and saw that the potential was that we would be trying to start up Unit 2 coming out of its refueling outage and restart of Unit 1 at the same time.

We felt like from a conservative decision making process that would not be a good place to put our operators in to try to do both of those activities simultaneously. So with the reactor building work and the drywell work progressing very well, we chose to go ahead and move up the refueling outage probably about three weeks from its original plan in order to try to get that outage accomplished as quickly as possible.

The remaining work in the drywell and the reactor building will continue to be done and we think we can get that finished somewhere by the end of January, maybe even mid February. But we will continue to progress on the balance of the plant. The majority of the remaining work is in the turbine building and our plan is to continue that work even though we're in an outage on Unit 2. So we'll get that work accomplished if we're successful in the outage on Unit 2 and get it back on line. Then we would subsequently go right to Unit 1 and we would start that subsequent and we still feel like we can make our commitment for a May startup with our plan. So it's just trying to integrate those two activities and make sure that we don't overload the critical resources we have which is really operating operations resources and trying to do both of those activities.

CHAIRMAN BONACA: So the plan is to restart it in May.

MR. BHATNAGAR: Sometime in May, that's correct. We're still going through a very detailed review. We're trying to just apply the right schedule for Unit 2, the scope for Unit 2 and how much work we plan to do in Unit 2 to make sure that we can do both of those activities.

CHAIRMAN BONACA: Okay. Thank you.

MR. BHATNAGAR: Did I answer the question?

CHAIRMAN BONACA: Yes.

MR. BHATNAGAR: Okay. Thank you.

CHAIRMAN BONACA: All right. We're done. Let's proceed to the final portion of this presentation.

MS. BROWN: All right.

CHAIRMAN BONACA: And then we'll break for lunch.

MS. BROWN: Mechanical and electrical equipment covered by this section includes equipment associated with systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling and containment and reactor heat removal. Equipment associated with systems essential to preventing significant releases of radioactive materials to the environment are also covered by this section. The NRC staff's review focused on the effects of the proposed extended power uprate on the qualification of the equipment to withstand seismic events and the dynamic effects associated with pipe whip and jet impingement forces.

Consistent with the ELTR guidance, the functional capability of nonmetallic components and mechanical equipment inside or outside containment is not adversely impacted by power uprate and the effects of increased temperature, pressure and flow are not significant for environmental qualification of mechanical equipment for power uprate.

This slide just lists --

MEMBER POWERS: When you do those analyses, you have a variety of new equipment in this plant. What is the high frequency component of the source term that you use?

MS. BROWN: You asked what was the high term frequently --

MEMBER POWERS: High frequency term.

MS. BROWN: High frequency term. Rick or J.D. Joe.

PARTICIPANT: Ask the question again.

MEMBER POWERS: I want to know what the 100 Hz load is on this for the seismic analysis of new equipment.

MR. CUTSINGER: This is Rick Cutsinger. On seismic at Browns Ferry, the high frequency code offers 20 Hz.

MEMBER POWERS: Twenty Hz. So relays, plotting equipment, things like that, just are essentially don't know there's an earthquake taking place.

MR. CUTSINGER: The low frequency can

affect some of the relays. In the 846 program, we try to look for the low rug in these relays to make sure we didn't have contact chatter.

MS. BROWN: Like I was saying, this slide just lists acceptance criteria and related guidance used by the staff. As the effects of operation and extended power uprate conditions remain within an environmental qualification envelope, the environmental qualification of mechanical equipment was found acceptable for all units up to and including 120 percent operation which bounds Unit 1 at 105 percent.

We're done unless there are any questions.

CHAIRMAN BONACA: Any more question for Eva? All right. Let's take a break for lunch and start again at 1:30 p.m. and I think we have two major discussions. One is the Human Performance and Applicable Training from TVA and then Risk and Human Performance Discussion from NRR.

MS. BROWN: Yes sir.

CHAIRMAN BONACA: And then of course, there will be a discussion of the members.

MS. BROWN: Also Mr. Dyer will be coming to address --

CHAIRMAN BONACA: Off the record.

(Whereupon, at 12:29 p.m., the above-entitled matter recessed to reconvene at 1:34 p.m. the same day.)

A-F-T-E-R-N-O-O-N S-E-S-S-I-O-N

1:34 p.m.

CHAIRMAN BONACA: On the record. Back into session. The next presentation is from TVA regarding Three Unit Staffing, Power Uprate, Human Performance.

MR. ELMS: Good afternoon. My name is Tony Elms. I'm an Operations Manager at Browns Ferry. The first item we'd like to discuss is Three Unit Staffing. Currently, the Operations Department meets Three Unit Staffing at Browns Ferry.

In anticipation of future staffing needs, I have two hot license classes that are progress. The first class takes our NRC exam in the 8th month of 2007. The hot license class takes their NRC exam in the 3rd month of 2008.

In addition to that, I have 15 nonlicensed operators that are in the training program. Those persons will be on-shift the second month of this year. I've just hired an additional class of nonlicensed operators. They'll complete the training program in the 7th month of 2008. There is an additional hot license class scheduled to start the 7th month of 2007 and another initial or NSGPO class scheduled for the 10th month of this year.

MEMBER SIEBER: What's the minimum shift compliment look like at Browns Ferry right now?

MR. ELMS: The minimum tech spec requirement is three SROs, five ROs and five AUOs. We presently have on-shift, we're on a five crew rotation, 12 hour shifts, we have five SROs, six ROs and 13 AUOs is what we have on shift at this time.

MEMBER SIEBER: And when you qualify the fire brigade, how many? Who is on the fire brigade and how many does it take out of your operating crew?

MR. ELMS: Browns Ferry has an independent fire protection organization that is not part -- They work under the Ops organization. They actually work for me, but they're independent of the 13 AUOs and that's five additional persons on each shift.

MEMBER SIEBER: Okay. And that's their only duty or do they do other things?

MR. ELMS: They do some maintenance activities, but their primary function is fire protection.

We also have persons that are supporting Unit 1 recovery operation. We currently have three

SROs and two ROs. These persons support the day-to-day testing and return to service of the systems on Unit 1 as well as interface with the operating units to make sure that the schedule is logically tied and the activities and the schedule can be supported by the Unit 2/3 organization.

Unit 1 organization has retained the services of many of our ex-SROs that retired from Browns Ferry. These SROs were instrumental in the recovery of Unit 2 and Unit 3 and are very knowledgeable in the process. They also help put the logic ties into the schedule. They are the sequence of the return to service of the systems as well as the testing to support these systems. These persons will eventually be the test oversight persons for our power ascension testing program as what many years of SRO experience and many years of recovery experience have been retained in these positions.

I do have a long-range staffing plan that goes out through 2013 to ensure that we have persons available. That does take into account attrition. I lost two SROs, one RO and three nonlicensed persons in 2006. For 2007, I don't anticipate losing any SROs, no ROs and less than five nonlicensed operators. So staffing looks pretty good going forward.

As far as the licensing requirements, these licensed persons are licensed on all three units. We rotate these persons through the units to maintain them proficient on all three units. So there's not any issue with them not being proficient on any of the units.

As you see at the bottom of the slide, 15 years equivalent experience at 105 percent. That's from 1998. Unit 2 in February of this year will end its fourth cycle at 105 percent. Unit 3 is in its second year of its fourth cycle at 105 percent power. So a lot of experience by the operators operating at 105 percent power.

MEMBER SIEBER: Do you have more than one simulator?

MR. ELMS: Yes sir, I do and I'll discuss that on the next slide.

MEMBER SIEBER: Okay.

CHAIRMAN BONACA: I have a question regarding -- You know yesterday we saw the MPSH calculation for the Appendix RKs where the operator within two hours has to isolate coolers and to provide sufficient head for the RHR. Is this process generalized already?

MR. ELMS: Yes sir, it is. It is in the

SSIs, the Safety Shutdown Instructions. It is part of that procedure and that time has been validated.

CHAIRMAN BONACA: And that was introduced I imagine when you went to 105 percent at Units 2 and 3.

MR. ELMS: That was actually identified during Appendix R audit at Browns Ferry.

CHAIRMAN BONACA: So you always had that provision.

MR. ELMS: We did not. We did not always have that provision. No, this was an additional operator accident. It came out of the Appendix R --

CHAIRMAN BONACA: Appendix R. Okay. So early enough. Okay.

MR. ELMS: For training, I own training. I hold training accountable and responsible for the performance of the Operations Department. Training consists or starts with a zero week or a staff week. During that time, either myself or the Ops superintendent attends training. We sit through all the classes that will be presented and we review all the simulator scenarios that will be presented. What that gives us is the ability to make sure that our expectations are being met in training as well as what is being taught in training.

All the persons on the Ops staff are required to do training observations on a monthly basis. This also provides quality feedback to the training organization on how well they're actually performing and meeting our standards and changes have been made based on that feedback.

In training week, the first scenario, and that happens on Monday morning, the crews come from midnight shifts. They work off midnight shifts. They come Monday morning. The first scenario they see on the simulator is an as-found or an evaluated scenario., That scenario meets the requirements for NRC annual exam scenario.

It tests their competency in tech specs, abnormal operating instructions and it takes them down one or more legs of the emergency operating instructions. It is not uncommon for one of these scenarios to be ATWS anticipated transient without scram, requires the operators to lower water to maintain level and maybe even emergency depressurize with rods out.

Another common scenario would be a containment problem where containment pressure would be elevated. We talked about the net positive suction head curves that could play into these scenarios at that time. There again, you know, you will be tested on one or more legs of the emergency operating procedures or the way those end and like I said, these evaluated scenarios do meet the criteria for NRC evaluated scenarios.

MEMBER POWERS: How about Appendix R scenarios?

MR. ELMS: We do evaluate -- We don't have an evaluated Appendix R scenario, but we do train on the Appendix R scenarios at least bi-annually and the nonlicensed operators were last trained on that the last cycle of 2005. We give six weeks of training each year divided up into six cycles and they were trained the last week of 2005.

MEMBER POWERS: What is the typical Appendix R scenario you train on?

MR. ELMS: We have 38 fire zones and we normally pick one of the more complicated ones. Fire Zone 16 is one that requires evacuation of the control room. One that has time critical evolutions associated with it would be a typical scenario that we would train on.

MEMBER SIEBER: Do you have manual operator actions for fire protection authorized for your plant and, if so, how many?

MR. ELMS: We have manual operator actions associated with the SSIs. We do not have any that are performed by the fire protection organization.

MEMBER SIEBER: But by operators for fire protection scenarios?

MR. CROUCH: They are performed by the operators, yes.

MEMBER SIEBER: Right, but how many of them do you have?

MR. ELMS: I don't know the number of manual actions. If you look at the Appendix R event, you wind up with an RHR pump injecting into the vessel with four SRVs open discharging into the suppression pool with a service water cooling the pool. And depending on which fire zone you're at is how many manual operator actions we have.

MR. CROUCH: Let's let Dave.

MR. BURRELL: We have -- The number of manual actions vary depending on the particular fire zone. One of the zones that Tony mentioned, Fire Area 16, which is (Inaudible) has the most operator actions and it entails 337 manual actions spread over 120 minutes. They vary from as little as low 40 depending on the fire area to (Inaudible).

MR. CROUCH: And we treat an operator

action as if you were manipulating two switches side by side, that's two actions.

MR. ELMS: And like Dave said --

MEMBER SIEBER: It's still big numbers.

MR. ELMS: Like Dave said, this Fire Zone 16 has the most because it does require evacuation of the control room.

MR. BURRELL: Right. And we have done comparisons with other BWRs and the number of manual actions is consistent with those.

MEMBER SIEBER: Now according to the rules, you require an exemption for each of those manual actions from the NRC. Do you have those exemptions?

MR. BURRELL: We don't specifically have those as exemptions. They are documented in our SER for Units 2 and 3 as part of the recent regulatory interactions. You have put those in our corrective action program for (Inaudible.)

MEMBER SIEBER: Well, some day you're going to have to resolve that.

MR. BURRELL: That's right in the guidance. I think it gives us two years either to resolve in the way of an exemption or to (Inaudible).

MEMBER SIEBER: Yes. Well, just so you're aware.

MR. CROUCH: We're fully aware of that.

MEMBER SIEBER: Yes. That's not a power uprate.

MR. CROUCH: No sir.

MEMBER SIEBER: That's an operate tomorrow issue. You have to do that no matter what.

MR. CROUCH: We understand, sir.

MEMBER ABDEL-KHALIK: You said that you have -- Each crew has three SROs and five ROs to run the three units.

MR. ELMS: That's the standard in the tech spec for minimum manning. That's correct.

MEMBER ABDEL-KHALIK: But what is the actual --

MR. ELMS: The shift compliment as it is now is five SROs, six ROs and 13 AUOs.

MEMBER ABDEL-KHALIK: Okay. So when you schedule a week training for the crew, how do you divide them amongst the two simulators?

MR. ELMS: We have staff persons that fill in on these. What you'll do -- One of these persons is a shift manager. So you have the shift manager on one crew. He'll take three ROs and a unit supervisor, maybe two unit supervisors and we have we call them back-up shift managers or a person that is a qualified SRO, shift manager qualified, that doesn't always work in that position. He'll take the lead on the second scenario with the other half of the group and then we fill in with staff persons to make a Charlie crew.

MEMBER ABDEL-KHALIK: But I guess my question is related to are there physical differences between the two control room simulators?

MR. ELMS: They're starting and our first cycle of 2006 started Monday morning. One of the simulators does have the upgraded EPU equipment model on it. It's 105 core load. Both of them are 105 core load. One of the simulators simulates the pumps, the condensate pumps, the booster pumps as well as the feed pumps for the EPU. So that's how we're training on the installed equipment. The other simulator mimics 105 percent uprate without the condensate booster pumps, condensate pumps and feed pumps.

MR. CROUCH: So the actual control room has some difference. They have the paperless recorders.

THE WITNESS: The paperless recorders. That's true. The span on the instrumentation for the simulator that has the uprated equipment on it.

MEMBER ABDEL-KHALIK: And those

differences are actually present in these two simulators.

MR. ELMS: Yes sir, that's correct.

MEMBER ABDEL-KHALIK: So if an operator is going through a requal training and enters one of the simulators and says "I have Unit 1 today" can the operator do that?

MR. ELMS: Yes, they can and these simulators are physically situated in close proximity to them and we swap the crews. Like the alpha crew will train on the non-uprated simulator to start with and then the next scenario they see they will go to the uprated simulator and we swap those back and forth so all the crews get equal time on all of the simulators.

MEMBER ABDEL-KHALIK: Thank you.

MR. ELMS: The two simulators disks provide us a great advantage as far as training. With a number of hot license classes that we have, it prevents or it lessens the amount of time that we have to train on the off hours. Getting an SRO license or even an RO license is hard enough and having to do that simulator training on the back shift or midnights makes it even that much more difficult. So a lot of benefit for the two simulators.

As INPO accreditation, November 30, the operations training program went to Atlanta and sat in front of the accreditation board. We did receive re-accreditation for all of our training programs for the operations training programs. That's a pretty intense process. It starts out with a self evaluation of your training process where you go through and look at yourself. INPO comes in and does a week followup with that to see if they identify any issues different than you do and then you go sit in front of the accreditation board and present your responses to those. As I said, we did receive accreditation for all of our training programs associated with that.

MEMBER SIEBER: Yes. When did you last get re-accredited?

MR. ELMS: November 30, 2006.

MEMBER SIEBER: Okay. So you're --

MR. ELMS: We just finished that up. We also --

MEMBER SIEBER: You shot at the hopper.

MR. ELMS: Yes sir. We also had the NRC requal inspection last year too. So our training program has been looked at by NRC and INPO within the last six months.

We got re-accreditation for the

nonlicensed operator training program, the reactor operator training program, the SRO training program, the STA program as well as the shift manager program.

Okay. We committed, we, TVA, committed to two cycles of requal training prior to implementation of the uprate on Unit 1. That first cycle of training was the last cycle of 2005 which would have been the sixth cycle of 2005. It finished up in December. That was the classroom portion of the uprate that included the procedures associated with it and the differences for the modifications.

The next cycle which would be the first cycle of 2007 is the simulator portion of that and I just spoke to that as to what the simulators look like, the differences between the simulators and how we make sure that the crews get equal time on each of the simulators.

For plant transient response, we use the simulators for several things and one of the things that we use the simulators for is just-in-time training and that's how we'll train for these large transients. Just-in-time training, we use it for our shutdowns. We use it for our start-ups. We use it complex, infrequently performed procedures such as our LOCA tests or RHR Logic test where we can go to the simulator, set it up and run it and see the actual plant conditions that we expect to see during this test. During that time, that gives the crew the ability to go through and validate the procedures, walk it down, make sure that the nomenclature matches what it's going to be, know the instruments they're going to look at, where they're at. They also get to see the expected plant responses from these transients or procedures or whatever they're going to do. It's a validation process for the procedures. At this time, that gives the shift manager the time to develop or to assign the roles and responsibilities for each person on the crew, determine what critical steps may be involved in these procedures, determine what human performance tools or techniques we'll use to ensure these critical steps are completed as written.

We also discuss what's the worst thing that could happen. It gives us time to develop the pre-job brief associated with these evolutions and the development of that pre-job brief, we look at any plant specific OE that may be out there as well as any industry OE that may be out there.

MEMBER ABDEL-KHALIK: So do you update your core design model in the simulator every cycle then?

MR. ELMS: Yes sir, we do.

MEMBER ABDEL-KHALIK: So how do you update your core design model in the simulator every cycle then?

MR. ELMS: Yes sir, we do.

MEMBER ABDEL-KHALIK: So how do you model three different cores in two different simulators?

MR. ELMS: We have both simulators meeting the 105 percent power at this time.

MEMBER ABDEL-KHALIK: But the core design in the three units may be different.

MR. ELMS: We will only be able to model two of them and if the decision is made midway through the cycle to upgrade Unit 1 or one of those units, we would shut the simulator down. We have to go in and reload the core design in there to 120 percent power.

MEMBER ABDEL-KHALIK: But let's say all units are operating at 105 percent power. You still only have the capability of modeling two cores.

MR. ELMS: Right.

MEMBER ABDEL-KHALIK: So how do you --

MEMBER SIEBER: You don't use the simulator to look at in-core kind of things. Right?

MR. ELMS: Well, we do. I mean we can change the core load and one of the things that we've had some issues with is late in core life, the notch works on the rods, you know the top notches have much more worth than they did at the beginning of core life. So we have the ability to go in and modify that core load or what the computer sees in there to mimic it as close as possible and we try to do that with our just-in-time training for our shutdowns and start-ups to get the core life where we're adding core life whether at the beginning of core life, middle of core life or end of core life prior to training on that simulator.

MEMBER ABDEL-KHALIK: I'm still sort of -- I'm lost. You can only model two cores on the two simulators.

MR. ELMS: That's true.

MEMBER ABDEL-KHALIK: And yet you say that the operators are trained to understand the response for all three units. How do you do that?

MR. ELMS: Now we have 2 and 3 cores are very similar and the Unit 1 core will be different. So we'll have one that is very similar to 2/3 and one that mimics Unit 1.

PARTICIPANT: I believe you're talking about consistent operator actions based on that as well. Right?

MR. ELMS: That's exactly right. Okay. Once the persons are finished at the simulator, the last thing that they'll develop is the abort criteria associated with whatever evolution that they're going to perform once they get back to the plant and that will be clearly delineated and the shift manager will have responsibility for determining when that abort criteria is met. Once we come back to the plant, we will -- whatever support is needed if we need instrument maintenance support or electrical maintenance support to perform the SI with procedure, we may need system engineering support. We'll gather those persons together as a group and we will walk down each one of their specific functions. So they have a copy of the procedure. They get the time to go walk it down to make sure they know (1) where they're going to go and (2) what they're going to do.

Also develop the pre-job brief, we've developed it at the simulator. We bring it back. We further look at any OE we may have, get input from the support persons as to what human performance tools and techniques they may need to use, have critical steps identified, see if they have any different steps that they believe to be critical than what we believe to be critical. They also discuss the worst thing that could happen. All that gets rolled into the pre-job brief. We hold the pre-job brief before we actually perform the procedures.

These will also be rolled into our -- We have a 12-week rolling schedule that the items are put in the schedule. It gives 12 weeks for each activity to roll in, gets reviewed from a system engineering, the scheduling organization, maintenance organization as well as the OPS organization. We also have a risk SRO. This is a STA qualified SRO that reviews that schedule for any risk associated with it and approves it by signing his name to it. We have critical evolutions meetings that anything that's deemed as critical or has generation risk comes before a group of people that includes a senior level manager. They review it. They decide are there any additional actions or what type of things need to be put in place. Where we would use peer checking? What human performance tools will be needed at this step? What level of oversight?

That's decided in the critical evolution and we have an NSGR sheet which is a nuclear safety generation risk form that's completed for that evolution and it puts in writing what type of oversight, what type of human performance tools. It lists the factors that are going to make this job successful.

MEMBER SIEBER: Do you have on-shift STAs?

MR. ELMS: Yes sir, I do. I have two STA qualified persons on each group both of which are licensed SROs and I have one nonlicensed STA that works day shift.

MEMBER SIEBER: Okay and they're all engineers.

MR. ELMS: They all are degree-ed. persons. That's a true statement, technically degree-ed.

MEMBER SIEBER: And do they work in the control room or do they do other things?

MR. ELMS: They will rotate with the other unit supervisors and set the units when their time comes to do that, outside position as well.

MEMBER SIEBER: Okay.

MR. ELMS: Okay. This just-in-time training, we also -- Training has what's called a single point of contact. This single point of contact is a training instructor that's assigned to each one of the crews and that person is held responsible and accountable for this crew's performance. That person will be the one that puts together the just-in-time training for the crew. He'll administer the training. When the evolution takes place, he'll be present in the plant to observe the crew to make sure that they perform as expected. He'll also look at any differences from the way that they've been performed and provide feedback to them and if necessary, he will enter items into our corrective action program.

Consistent operating response, one additional operator action for termination of drywell cooling Appendix R event, we've discussed this at length. There are three different ways that we terminate this drywell cooling and the termination of the drywell cooling is we stop the RBCCW flow to the drywell coolers. The blowers themselves continue to run and it's depended upon which of the fire zones that we have the fire in is to how we terminate this cooling flow to the drywell.

One of them is we do it from the control room. If we don't have to abandon the control room, we just trip the pumps from the control room. Another is we have it's called an essential and nonessential loop on the RBCCW. It is an isolation valve that lets the water flow into the drywell to cool the components in the drywell. It's closed under other conditions and the worst case is we have to go to the 480 V shutdown boards and trip the pump breakers.

And there were no other changes made based on the Appendix R, no procedure changes. The mitigation philosophy for our transients remains the same.

We have as we spoke many operator actions. Those are broken up into specific time frames. All of those have been validated. The SSIs for Unit 1 or safety shutdown instructions for Unit 1 have been written. All those actions have been validated and verified and as I spoke, the nonlicensed persons were trained last on SSI the last cycle of 2006.

For power ascension testing modifications, on this page minor equipment differences, you know, obsolescence has been one of the reasons why you would see differences in the control room and mainly you would see that in the recorders. We have some of the -- We used to have the paper records. Those have become obsolete. So we are changing over to the paperless recorders. That would be a reason for an equipment difference.

Improved plant performance and additional margin. Once we install the upgraded pumps -- Well, they're installed in Unit 1. When we install them in Unit 2, these at 105 percent will be three 50 percent pumps for condensate, condensate boosters as well as feed pumps. So additional operating margins to the operator crews, we'll be able to take a feed pump, a booster pump and a condensate pump out of service and maintain 100 percent power.

The sequencing of the EPU modifications. Ashok spoke earlier about the sequence that we're going to do, the modifications. Unit 1 has already been completed or is in the final stages of being completed. The Unit 2 outage which starts in the latter part of February, we'll put everything except the high pressure rotor and the high pressure turbine and the steam dryer modification won't take place on Unit 2 and then we'll follow the Unit 3. This design is not unique to the industry.

The power ascension testing under command and control, Op owns the plant. We have the final say-so in what goes on. The shift manager is the one that's in control of all activities at the plant. He has the ability and the authority and the expectation to stop if he's unsure. Do not proceed in the face of uncertainty. If the procedure is not right, the expectation is that they stop and get it fixed. They don't continue on.

He needs to make sure that the right human performance tools are used for the right steps. Unit 1 testing team that I spoke of earlier will be involved in this test. They have exactly the same expectations. Another task that the -- Or another action that the shift manager is tasked with is to ensure that the proper plant conditions are met prior to starting any test or evolution and additionally that they have the correct manpower prior to starting into any of these tests.

MEMBER ABDEL-KHALIK: How would they know that the procedure is incorrect during this process?

MR. ELMS: Well, they may identify it on a walkdown. We talked about walking it down on a simulator. We talked about walking it down at the plant. Now one of those, either one of those, you could catch a nomenclature issue. You could catch something that was out of sequence. You could catch the fact that you were verifying something on another unit. You know our procedures, we have three units. So during the procedure upgrade, I mean that's a possibility. So the walkdown process is one. Doing it on the simulator is another one. Actually getting to the step to perform it and say, "Hey this is not right."

MEMBER SIEBER: The sequence.

MR. ELMS: That's exactly right. And once we get into these tests, we have 24 hour support from engineering as well as the procedures section. We take several people to change a procedure. We have the engineering section out here for technical support. The operations procedure group will be out to make the change and then it has to be issued through our document control organization. So we have those persons 24/7 once we start into these major evolutions.

MEMBER SIEBER: Your shift supervisors have that authority for a one-time deal procedure change. Right?

MR. ELMS: We can make minor pen-and-ink changes on procedures, but we don't do that on a regular basis.

MEMBER SIEBER: But you can.

MR. ELMS: We can do that. That's true. Yes.

MEMBER SIEBER: If you have to, you would do it.

MR. ELMS: Yes sir. Okay. The transient testing, I spoke about what all happens in preparing for the transient testing and the oversight associated with it and the process we're getting ready for.

Another issue that we deal with is the turnover of systems and especially on Unit 1 and we use the SPOT process and that's a system preoperability process is what that is.

And it has two phases to it. It has a SPOT 1 and a SPOT 2. And the SPOT 1, that occurs after all the maintenance on the system is being completed up to the point to allow testing. At that time, the Ops organization will go in and establish status control on the system. All the testing on the system will be done and that includes any logic testing, any flow testing, any MOVs. If it has initiation from instrumentation, the instrumentation department will have run their part of that system logic SR and that takes it up to the point of supporting plant, whatever phase the plant's in. It doesn't necessarily take it to operability.

The second phase of that is the SPOT 2 process and that's after all the testing has been done and you know the system performs as it's designed. We can -- At that point, it will support a specific plant condition. It might not be tech spec operable and it may have some outstanding issues associated with it. And you have two different types of issues associated with it at this time. You'll have an exception which is something that does affect operability and the system cannot be made operable until that exception is cleared. You will have a deferral and a deferral is a maintenance activity that needs to be completed but doesn't affect operability. That may be a packing leak on valve. It may be a drain valve that's leaking through, something minor in nature but it doesn't affect operability.

Also prior to the SPOT 2, the systems are walked down by the operations department. A list of housekeeping items are identified. A list of whatever is out there is written down and has to be dispositioned to SPOT 2. At this time, we also review the backlog associated with this systems. We have systems on Unit 1 that haven't been operated in 20 years or haven't been operable in 20 years. You have to go back through the backlog and see what's out there that needs to be fixed on that system. So that's one of the things that happens prior to SPOT 2.

MEMBER POWERS: Maybe you went pretty fast over this. You've maintained a component. This is done. Then you have to do the post maintenance testing and that's done by operations?

MR. ELMS: That's correct. If it's instrumentation, I mean, if it's a water level instrument --

MEMBER POWERS: I understand.

MR. ELMS: But if it's a flow test, if it's a valve operability test, if it's a valve timing test, those belong to the operations department.

MEMBER POWERS: And operations does that and they go through a variety of things before they can declare operability.

MR. ELMS: That's correct. And one of the things that we use is we use a system called iTEL and iTEL is our tracking mechanism for items that have been identified during the process to bring it up to operability. Once you get tech spec operable, you track open items in the tech spec LCO tracking log at that time.

Another thing that happens prior to this SPOT 2 occurring is the plant side system engineering develops a system health report for the system and what that does for us is that forces him to go back and look at what outstanding issues are associated with that system and we have a SPOT 2 meeting that's attended by senior level management as well as the Unit 1 personnel. One of the persons that comes to that meeting is the system engineer and he presents the health report for what that system is going to look like once we take it.

And one of the big things that has to be done at that time is the critical spares have to be identified and either ordered or on hand. The potential to miss that is pretty high if you don't put it in the process early on. So we capture it at SPOT 2.

The acceptance criteria for testing, that's pretty straightforward. I mean it's spelled out and if you're looking at a surveillance, it's straightforward as to what -- It's denoted with AC stiff as to what acceptance criteria is and this is a go or no-go. I mean if the pump doesn't retrade its flow, if the turbine doesn't come up to speed in time, your acceptance criteria is not going to be satisfied.

Compared to the original start-up testing you'll see on the following slide as you well know we're going to have to do some large transient testing. We didn't do that originally but this generator load reject and MSIV closure as well as the pump trips, that is going to ensure that our plant operates by design and we have a quality product at that time. The steam dryer monitoring, we spoke a little bit about that earlier. We'll look at the carry over on that and we've also got the strain gauges that will be on steam lines as well as the accelerometer. So that will be monitored as we come up in power.

In short, you know the Operations Department, we feel comfortable we have the staff to run three units. We're comfortable with the training that we've received to operate the three units and then we're looking forward to a three-unit operation. Any questions?

MEMBER SIEBER: Yes, I have a couple. You're in charge of the Operations Department.

MR. ELMS: Yes sir.

MEMBER SIEBER: Do you have SRO license?

MR. ELMS: I did hold an SRO license. I have 26 years at TVA and all of that has been at Browns Ferry and I held a license for more than 15 years.

MEMBER SIEBER: Okay. How many people at Browns Ferry hold current licenses who aren't in Operations for doing other jobs like engineering or administration or what have you?

MR. ELMS: There are three people in training that hold an S -- Four people in training that hold an SRO license and all other persons with us RO licensing or either they belong to the Operations

Department or they're on loan to other departments.

MEMBER SIEBER: Thank you.

MR. ELMS: Any further questions?

MEMBER ABDEL-KHALIK: Steam dryer monitoring, I guess that's also operated by Operations. Is that correct?

MR. ELMS: That will be in conjunction with system engineering.

MEMBER ABDEL-KHALIK: So physically where is that data going to be collected?

MR. ELMS: That data is collected -- On Unit 2 the data was collected on the first floor of the reactor building on the south side. Those gauges were installed inside the drywell, run through a penetration and all the data was recorded external to the drywell.

PARTICIPANT: That's inside the reactor building but outside the drywell.

MEMBER ABDEL-KHALIK: Thank you.

MR. ELMS: Anything else? Thank you for your time.

CHAIRMAN BONACA: Thank you.

MR. CROUCH: Dr. Bonaca. We had a couple other --

CHAIRMAN BONACA: Mr. Crouch has some

answers to questions raised. He can provide it now.

MR. CROUCH: Okay.

MEMBER SIEBER: Thanks very much.

MR. ELMS: Thank you.

MR. CROUCH: One of the questions that was asked in one of the previous sessions was concerning the unfiltered end leakage into the control room and back in 2003, we ran a tracer gas test and the unfiltered end leakage that was measured by that method was 817 SCFM as opposed to what's used in the calculation which is 3700, 3800, because that was the old number and we just retained that for the calculations. But it was 817 SCFM.

Another question that was asked was what's the amount of curies that are released on an annual basis? For the airborne with no fission activation products in it, it is $4.45e^{-3}$ curies for iodine and it is $4e^{-3}$ curies for particulates. In the liquid, we have $5.75e^{-1}$ curies with no alpha emitters. So that's that.

The dose at the boundary of the site is measured and it typically runs 59 to 60 millirems per year and we have seen no change in that value from the time we initially started operating until now and even when we were in periods of nonoperation such that all three units were shut down, you saw the same number so that the site boundary is far enough away from the plant that it is virtually unaffected by plant operation.

MEMBER POWERS: You didn't give us anything on noble gases.

MR. CROUCH: No, I do not have anything on that.

MS. MARTIN: Good afternoon. I'm presenting on the Human Factors Engineering portion of the power uprate. These are the areas that I reviewed as a part of my evaluation to ensure that the uprate did not adversely affect operative performance at Browns Ferry. These are the regulations that I use as my basis for my evaluation.

These are the five standard areas that I reviewed as a part of my evaluation for the power uprate. The first area is the emergency and abnormal operating procedures. The changes consisted primarily of business to numerical values which represent plant status and there were no new procedures in the areas of BOPs or AOPs.

The next area is operator actions which are sensitive to the power uprate. There were no new operator actions in the areas of emergency or abnormal operating procedures and no changes in the actual time it would take the operators to perform their actions and no change in the philosophy as well.

There were four main new actions created in the safety analysis portion.

MEMBER WALLIS: Were there changes in the time it takes the operator? There's no effect of this power level on the time response?

MS. MARTIN: No.

CHAIRMAN BONACA: For example, no change?

MS. MARTIN: Sorry.

CHAIRMAN BONACA: For example, the response time of the operator to adverse event?

MEMBER WALLIS: Adverse event. Usually the operators have less time to respond to an adverse event.

MEMBER SIEBER: ATWA B in the procedure.

MEMBER WALLIS: Not in the --

CHAIRMAN BONACA: So now we're talking only about the procedures.

MEMBER WALLIS: We're only talking about the procedures.

MEMBER SIEBER: They have to do it faster.

CHAIRMAN BONACA: All right.

MEMBER WALLIS: The addition -- action to completion.

CHAIRMAN BONACA: Where should I ask the question regarding the scenario that we just heard?

MEMBER CORRADINI: I knew we were going to get into that.

CHAIRMAN BONACA: Appendix R.

MEMBER CORRADINI: Is this the right point to ask that?

CHAIRMAN BONACA: Appendix R, the actuation of -- Well, the turning off the coolers in order to increase back pressure to deal with the Appendix R event. I mean is that -- That's a new action that the operator has to perform.

MEMBER SIEBER: Pretty quickly too.

MS. BROWN: Yes sir, but it's not in the abnormal operating instructions or the emergency operating instructions.

CHAIRMAN BONACA: You're going to talk about it somewhere else, but you're going to address it.

MEMBER SIEBER: Yes, where is it?

MS. BROWN: They're in the safe shutdown instructions for Appendix R. Those are reviewed by the inspection staff as part of the inspection activities where they go in and do those actions that you guys are familiar with where they have to validate the feasibility and reliability of those actions under Appendix R.

CHAIRMAN BONACA: When is that going to happen?

MS. BROWN: Next week, the staff is going out to look at those, I believe, was it 22 or so safe shutdown instructions. So those are being validated by the inspection staff onsite next week, selected ones.

CHAIRMAN BONACA: Do they have human factor capabilities?

MS. BROWN: I'm sorry. What exactly do you mean by that?

CHAIRMAN BONACA: By that I mean, you would want to understand. I mean this is an action that is pretty critical. It's counter intuitive because why would you try to increase pressure in containment except you need by pressure. So are the staff that go to review this implementation capable of evaluating that assessment? You wanted to add something, Michael.

MEMBER CORRADINI: No, you're going -- I'm trying to figure out where we should ask the question about how one enters into this regime and if we should wait, that's fine.

CHAIRMAN BONACA: I'll be glad to wait if at some point it's being addressed.

MS. BROWN: I don't believe it's addressed in the staff's presentation. But I'll try to field it. I actually used to do some of this review for the agency. So I'm not exactly sure I understand what your question is.

CHAIRMAN BONACA: My question has to do with an action that we have seen presented to us.

MS. BROWN: Yes sir.

CHAIRMAN BONACA: That deals with providing sufficient back pressure to the RHR pump during an Appendix R scenario so that you have in fact a flow going to the wetwell and the issue is there is a new operator action. We are looking for a representation by TVA that they are addressing that. It's an action and who is evaluating the feasibility of this action?

MS. BROWN: When the originally came to light, there was also a concern that it may be needed for the operating units. So the senior resident inspector and the resident inspection staff did go in and validate and verify that the action was appropriately placed and trained on as well as the fire protection staff who routinely goes in as part of their triennial inspections to review the feasibility of operator manual actions and there is a set of criteria that I'm sure you guys are very aware of after the operator manual action rulemaking. That criteria is still used by the staff to validate the feasibility. We look at environment, temperature, whether or not it's marked, those types of things. So yes, sir, I do believe that the inspector staff is more than capable of determining the feasibility and reliability of a manual action for Appendix R.

MEMBER ABDEL-KHALIK: Now entry into this leg of the procedure required indications that can only be obtained in the control room. Now who makes the decision and maybe the Applicants can answer this. Who makes the decision that we have entered this leg of the procedure and indeed that this action has to be taken?

MR. ELMS: My name is Tony Elms and I'm Operations Manager and the shift manager makes the determination of when you enter the safe shutdown instructions.

MEMBER ABDEL-KHALIK: Now what procedure does he have in his hand that tells him that entry into this leg of the procedure is required?

MR. ELMS: SSI 001.

MEMBER ABDEL-KHALIK: And this is not a part of the emergency operating procedures.

(Off the record discussion.)

MR. ELMS: Okay. The shift manager, he makes the determination as to when the SSIs or safe shutdown instructions are entered and this is an independent procedure that is outside the emergency operating procedures. I mean this you just set the emergency operating procedures aside once you get into the SSIs and you're correct. The indications are from the control room. In the entry conditions, you have a fire obviously and it say "the Unit 2 or Unit 3 and this is the 2/3," the Unit 1, it will 1/2/3 when it changed, "is greater than atmospheric pressure and the magnitude of the fire has the potential to affect safe shutdown capacity by multiple failures or spurious actuations of systems/components have occurred or erratic or questionable indication on numerous main control room instrumentation have occurred or multiple trains/channels of safety related equipment are threatened by the fire." At that time, you'll make the determination that you need to enter these safe shutdown instructions.

MEMBER ABDEL-KHALIK: Now this set of

instructions is not very specific.

MR. ELMS: Oh, it is specific. It's 38 different -- From this you have to go identify which fire area you're in. You have to identify the fire area. Then you have specific directions based on the equipment that's available with the fire in that area as to what actions you take.

MEMBER ABDEL-KHALIK: Well, numerous spurious actions or indications in the control room is sort of in the eyes of the beholder during a severe accident. So some people may interpret two spurious indications as numerous and they would initiate this leg of the procedure immediately. Other may say --

MEMBER SIEBER: Then you have to look for the fire.

MR. ELMS: You have to look for the fire. You have to have the fire also.

MEMBER SIEBER: You go to the fire panel.

MR. ELMS: But you have to have a fire that -- This is all predicated on the fact that you have a fire in one of the safe shutdown areas.

MEMBER ABDEL-KHALIK: So the shift supervisor makes that determination.

MR. ELMS: Right.

MEMBER ABDEL-KHALIK: Who actually takes

that action?

MR. ELMS: Once the shift manager made that determination, you have assigned persons. There are four or five persons that will have actions that will be dispatched from the control room with copies of the procedures and they'll start into implementation of the safe shutdown instructions and those are our nonlicensed operators that I spoke about --

MEMBER ABDEL-KHALIK: They're AUOs.

MR. ELMS: Exactly right. Those will be the persons and in some instances in Fire Area 16 when we evacuate the control room even the operators would have actions to leave the control room at times. But we disperse the procedures to the nonlicensed operators. They go out. They have required actions to be completed. Once they complete those required actions with the radio, telephone, whatever form of communication is in the area, get back to the control room and say, "I've completed up to step whatever" and it says in the procedure, once you've completed this you call the control room and you tell them you're complete up to this step. So they know to stop there.

The operator will be tracking along in his procedure and he'll tell them at the prescribed time "continue on in your procedure" and they will go to the next step and complete it in that manner.

MEMBER ABDEL-KHALIK: Okay. Thank you.

MEMBER SIEBER: Pretty standard.

CHAIRMAN BONACA: Thank you.

MS. MARTIN: These are four main operator actions which are accredited in the safety analysis. The response time for these manual actions was not changed and there was only one change to the available time for the operator to complete their action and that is for the CAD system initiation. The available time was previously 42 hours and it's been changed to 32 hours.

There was no change again in the actual time it takes for the operator to complete this action. It remains at five minutes. Staff found this change to be acceptable with review of the environmental conditions of the manual actions and the time available and the time necessary for the operator to complete their actions.

The next area I reviewed was the control room alarms and displays. There were several set points which were changed in the RPS system and changes to instrumentation and aids in the control room. This will be covered in the training of the operators prior to modifications.

The next area I reviewed is involving the SPDS system. In Units 2 and 3, the inputs/outputs were changed to reflect the changes due to the power uprate. And in Unit 1, there will be an SPDS installed similar to the same one that exists for Units 2 and 3.

MEMBER ABDEL-KHALIK: I'm sorry. Could you go back one slide? What was the scope of your review in this area? What did you actually do?

MS. MARTIN: I reviewed which set points were changed and what was changed as far as the aids in the control room and whether or not TVA committed to reviewing these changes and training all the operators on the changes required to modifications due to the uprate.

MEMBER ABDEL-KHALIK: Okay. Thank you.

MS. MARTIN: The changes to the SPDS system will not affect the emergency operating procedures executions.

CHAIRMAN BONACA: The SPDS is identical to the one for Units 2 and 3?

MS. MARTIN: Yes, it will have the same design and intent as the one that currently exists for Units 2 and 3. And as I stated previously, TVA committed to reviewing all these modifications to identify all the required procedures and simulator changes. That will covered in the training. The simulator changes as they stated previously in their presentation includes the hardware and software changes and updates to the modeling of the core. They committed to collecting date during startup and implementation that will benchmark the simulator.

In conclusion, we bound the changes to the plant and the training with regards to human performance to be acceptable with respect to human factors engineering.

MEMBER ABDEL-KHALIK: Have you actually done onsite inspections to see that the control room alarms, controls and displays have been modified in accordance with what the Licensee has stated?

MS. MARTIN: No.

MEMBER ABDEL-KHALIK: So how did you arrive at the conclusion that these changes are --

MS. MARTIN: Acceptable.

MEMBER ABDEL-KHALIK: Yes. Are acceptable.

MS. MARTIN: All of the modifications have not been completed. So we just have the commitment by the Licensee that these changes will be made and will be covered in training once they've been made.

MEMBER ABDEL-KHALIK: Will there ever be a step where you can independently verify that these changes have actually been made in accordance with what the Licensee had stated?

MS. BROWN: We also have inspection staff that's going to be onsite because remember Unit 1 is restarting. So some of your concerns about validation of the operator training and human factors aspects can be if necessary and if needed by the staff validated by the inspection staff. Just for example there's going to be around-the-clock coverage during the start up of the unit. There will be an NRC inspector in the control room during the startup phase. I think we're doing 24 hour coverage for whatever period of time that it takes.

MEMBER ABDEL-KHALIK: I'm just trying to understand how much effort was involved on your part to get to the point where you can list the conclusions on the last slide.

MS. MARTIN: I'm sorry. What's the specific question that you're asking?

MEMBER ABDEL-KHALIK: How much effort was involved on your part to reach the conclusions that you list on the last slide?

MS. MARTIN: I would say a lot of effort went into my review.

MEMBER ABDEL-KHALIK: Good answer.

(Laughter.)

MS. MARTIN: A great amount. I reviewed everything that they submitted and we went back and forth for request for additional information to make sure that all the modifications that they made to the plant or that they planned to make the plant that they committed to making changes and making training as far as human performance is involved to make sure that it does not adversely affect the safety of the operation of the plants for Units 2 and 3 and for the restart of Unit 1.

MEMBER ABDEL-KHALIK: Thank you.

MS. MARTIN: You're welcome.

CHAIRMAN BONACA: It would have been actually -- I mean my understanding is that prior to the restart there will be a full inspection and so many of these commitments will be verified, not all of them probably, but on an audit basis and so I was looking at the SER for a comprehensive commitment list and I didn't find it there.

MS. BROWN: At the back. I believe it's either Section --

CHAIRMAN BONACA: Yes, but it's --

MS. BROWN: It might be five or six.

CHAIRMAN BONACA: It's a limited -- Yes, there is a small set.

MS. BROWN: It's a limited set and --

CHAIRMAN BONACA: It's just one page and I think that there are many more commitments than that.

MS. BROWN: There are a lot of commitments. Some of them are 120 specific and some of the ones we listed are just the most important ones that the staff found necessary to verify.

CHAIRMAN BONACA: Yes. Confirmatory actions.

MS. BROWN: Yes sir.

CHAIRMAN BONACA: But I think that it would have been interesting to see the whole list of commitments because I'm sure there are -- I would suspect there are literally hundreds of commitments.

MS. BROWN: There is a restart oversight panel list that I believe has been issued publicly with a listing of all the outstanding items that the staff will be looking at and the Licensee will be completing as part of that effort. That's definitely publicly available.

MEMBER CORRADINI: Can I ask a broader question because I don't -- This is a part of NRC that I don't completely understand. So does NRR participate actively with inspection and enforcement? So let's say there's a list. You've looked at this now from a paper trail. Now it proceeds over to you're getting close to restart and you said there's a restart team. Is that all from the region in I&E or NRR folks participate as a team with that? Do you see my question?

MS. BROWN: We have individuals that support the inspection staff as needed from NRR.

MEMBER CORRADINI: Onsite?

MS. BROWN: As needed.

MEMBER SIEBER: They go to the site.

MEMBER CORRADINI: I'm sorry.

MEMBER SIEBER: They go to the site from here.

MEMBER CORRADINI: Okay. Fine.

MS. BROWN: There are some individuals.

MEMBER CORRADINI: Only if inspection enforcement ask for it or it's a normal procedure to have an onsite?

MS. BROWN: I think for human factors I think we have two individuals that will be onsite as part of this restart activities.

MEMBER CORRADINI: Okay. Thank you.

CHAIRMAN BONACA: Any other questions? So then we move to the Risk Evaluation.

MS. BROWN: Yes. Mr. Stutzke.

(Off the record comments.)

MR. STUTZKE: I'll get out my weapons here.

CHAIRMAN BONACA: Okay. So.

MR. STUTZKE: My name is Marty Stutzke, a Senior Reliability and Risk Analyst in the Division of Risk Analysis NRR.

MEMBER KRESS: I'm going to be George Apostolakis.

(Laughter.)

MEMBER CORRADINI: I'm going to be Tom Kress.

PARTICIPANT: George, you've lost a lot of weight.

MEMBER CORRADINI: I thought you were going to say something else.

MEMBER POWERS: And look how much hair he's grown.

MEMBER CORRADINI: That's what I thought you were going to say.

MEMBER SIEBER: I'm going to get a copy of the transcript.

MEMBER POWERS: I thought he was going to say something more delicious.

MEMBER SIEBER: Yeah, go ahead.

(Off the record discussion.)

MR. STUTZKE: Okay. So for this session, I'm going to talk about the staff's review of the Licensee's risk evaluation of the 120 percent EPU with the exception of the containment accident pressure credit which I believe we finished yesterday unless you had some more time over the evening to think about it.

CHAIRMAN BONACA: We may have some additional questions, yes, before it's over.

MEMBER CORRADINI: Yes, I think we might.

MR. STUTZKE: I would not be surprised.

Whenever one looks at a risk evaluation, you have to decide what parts of the PRA you need to adjust and what you don't have to adjust. This is a list on Slide No. 2 of things that were not adjusted. I should make a few comments so you understand.

The PRA structure itself is called a linked event tree structure. It's implemented in the risk man code. It's markedly different from the link fault tree structure such as the staff's SPAR models. Everything is done is an event tree. So it changes how one has to go about reviewing this sort of thing.

CHAIRMAN BONACA: This analysis was done by TVA.

MR. STUTZKE: The analysis was done by TVA. That's correct.

MEMBER CORRADINI: So can you for the naive give us 25 words or less about the difference between linked fault tree and linked event tree? I'm sorry.

MR. STUTZKE: The idea of the linked event tree is all the branch points probabilities are independent. So you can just multiply them out. So the event tree structure tends to be very large, large quantities of events to get through the accident sequence.

MEMBER CORRADINI: So just for sake of example, it would be like in Appendix 8 of Wash 1400 where all the containment failure modes were essentially independent.

MR. STUTZKE: That's the notion.

MEMBER CORRADINI: Okay. Thanks.

MR. STUTZKE: That's probably enough said. There are proponents of both methods and both methods have known weaknesses like this and we could probably debate it for --

MEMBER CORRADINI: That's fine. I just wanted to make sure I understood.

MR. STUTZKE: Yes. That's the idea.

MEMBER POWERS: We could debate it but not productively.

MR. STUTZKE: That's the point. The level 2 model is a simplified LERF type of calculation like this. As far as the external events and shutdown risks, the Licensee treated them qualitatively, not quantitatively. That's in accordance with our NUREG Guide 1-200 on PRA quality. They didn't identify any new vulnerabilities like this.

I'll remind you we're not here to actually estimate the change in risk. We're trying to use the PRA to decide whether we have a question about a good protection or not. So you don't need to be necessarily as quantitative or as precise as you would for a risk informed type of application.

For the effected PRA elements, Slide No. 3, there were changes in the success criteria, credit for enhanced control rod drive flow, a number of relief valves that needed to operate during ATWS events and of course a cap credit increase like this.

Thus changes then were reflected in changes to the event tree structures and into the fault tree structures was necessary like that. Also some of the human failure event probabilities changed as a result of the power uprate.

One thing I should point out, it's an interesting effect, is when the Licensee first submitted the Units 2 and 3 risk assessment models they were predicated on the assumption that Unit 1 was shut down, permanently shut down. They then updated that where they have a complete three unit linked model assuming Unit 1 is now operating. Core damage frequency went down. The operation of Unit 1 is actually beneficial in certain aspects to the operations of 2 and 3.

MEMBER SIEBER: Can you tell us how that is?

MR. STUTZKE: It's because of the shared systems and I believe it's a service order related effect.

CHAIRMAN BONACA: The more plants you add and nowhere is the risk.

MEMBER POWERS: The risk goes up. The core damage frequency for the plant may go down.

MR. STUTZKE: That was my first reaction

when I saw this is let's build more units.

CHAIRMAN BONACA: Yes.

MR. STUTZKE: It's safer. But it's a curious type of effect. Okay. With respect to the success criteria, the Licensee reevaluated plant behavior using the MAAP code to come with some changes in success criteria. One thing that happens is when you're at the uprated power the CRD system is simply not capable of providing adequate flow for the first six hours of transients. The scenario is something like this. You would lose main feedwater system, HPCI and RCIC systems and then it's conceivable you would use CRD system to provide some flow into the reaction. You would do that if you were unable to depressurize and get on to low head types of systems.

MEMBER KRESS: Hasn't it melted the core by then?

MR. STUTZKE: At six hours, it depends on the type of scenario. Not always. At Unit 1, they didn't even model the CRD system because they got such little benefit out of it like that.

MEMBER CORRADINI: So can I say it back to you so I get it? So you're saying what is the sequence of things that failed that you then have to ask for the use of the enhanced CRD? Can you just repeat that? I'm sorry.

MR. STUTZKE: The other high pressure systems, feedwater, HPIC, RCIC.

MEMBER POWERS: What's amusing about that is that it's the CRD flow that bridged through the Browns Ferry fire.

MR. STUTZKE: That's correct.

MEMBER POWERS: And so now that poor CRD flow has been relegated to the cutting room floor after its heroic activity, yea, these many years ago. It's a sad commentary, Terry, on the --

MEMBER KRESS: It had its 15 minute of fame.

MEMBER POWERS: Yeah, it had its 15 minutes. Actually it was almost 12 hours of fame.

MR. MIMS: Marty, this is Bill Mims, TVA. One correction to the slide is we do, in Unit 1, take credit for CRD but it's late credit. It's after six hours. So we do take a limited amount of credit for it.

MEMBER CORRADINI: But given -- I just want to make sure I understand again. But given that you've gone to 120 percent, there's not enough flow in the enhanced CRD flow to make a difference in the first six hours. Is that what --

MR. MIMS: Yes, that's correct. In the previous to the EPU for high pressure injection, the CRD early on was enough to prevent core damage. But with the additional power, the additional heat, it's no longer credited for early-on injection.

MEMBER KRESS: That means you exceed the 2200 peak clad temperature. Is that --

MR. MIMS: Right. You would -- We would not credit CRD for preventing core damage early on all by itself enhanced flow.

MEMBER CORRADINI: So you're in this no-man zone over this, but you've entered into the potential core damage. The way you answered that is you passed a set point and therefore there shall be core damage.

MR. MIMS: Right. CRD by itself, enhanced CRD flow by itself early on is not credited to prevent core damage.

MEMBER ARMIJO: At the 105 percent or 120 percent?

MR. MIMS: At the 120.

MEMBER ARMIJO: At 105, what is it capable?

MR. MIMS: We're still taking credit for it.

MEMBER SIEBER: Well, that's it then.

MEMBER KRESS: Yes, we're through. Sorry. Go ahead.

MR. STUTZKE: There was also a change to the success criteria for the number of relief valves that need to operate during ATWS from 9 of 13 to 11 of 13. It's a very small change because the probability of the event is dominated by the common cause failure of all the valves. It probably doesn't matter.

MEMBER CORRADINI: Can I ask another question just for the sake again of just some sort of perspective? For Vermont Yankee at 120, is this the same sort of effect?

MR. STUTZKE: On the CRD flow?

MEMBER CORRADINI: Yes.

MR. STUTZKE: No.

MEMBER CORRADINI: Other BWRs that are at 120?

MR. STUTZKE: There aren't any other at 120.

MEMBER CORRADINI: I thought it was Quad Cities.

MEMBER POWERS: This is a very big core.

MS. BROWN: It's like the fifth largest.

PARTICIPANT: It's a large core.

MR. STUTZKE: I can't really answer it. At VY this was not an issue.

MEMBER CORRADINI: Okay.

MR. STUTZKE: This is the only time we've really seen a change of success criteria that had a notable impact on the CDR like this. You can really see it.

Okay. Since Dr. Kress is now Dr. Apostolokis, we'll talk about human reliability.

MEMBER KRESS: I'm going to ask you why you didn't use THERP.

MEMBER CORRADINI: What the hell is THERP?

(Laughter.)

MEMBER SIEBER: Nobody knows what it is.

MEMBER POWERS: You got it backwards. You used THERP. Why didn't you use ATHENA? That's what you're supposed to say.

MEMBER KRESS: I'm sorry, Marty. Go ahead.

MR. STUTZKE: That's okay.

MEMBER POWERS: And then you got wax eloquent about why you hate the EPRI HRA calculator.

MEMBER SIEBER: Yes, you can read the whole testimony.

MEMBER WALLIS: Well, how did you estimate the --

(Laughter.)

MEMBER KRESS: He's going to tell us.

MEMBER WALLIS: He's going to tell us?

MR. STUTZKE: Okay. Yeah.

MEMBER KRESS: He didn't. They did.

MEMBER WALLIS: What does "considered how" mean? Does it mean they had a way of calculating which was reliable?

MR. STUTZKE: No, they started out with a simple ratio of the powers.

MEMBER WALLIS: They assumed it was proportional.

MR. STUTZKE: They assumed it was proportional. Okay. The reason why --

MEMBER WALLIS: That was inversely proportional. It's -- less time you get more errors. So that can't be proportional.

MR. STUTZKE: Inversely proportional.

MEMBER WALLIS: That's different.

MR. STUTZKE: 7/8ths to be precise.

MEMBER WALLIS: Was that reasonable?

MR. STUTZKE: I believe it's okay because you have to understand how the human error probabilities are actually calculated like this and you're probably aware of the concept of a time reliability correlation that's a nice smooth curve that says find out the available time I can pick off the exact probability of the human error like this. So in concept if the time were to be reduced, for example, by one second, I could calculate a change in the probability. We all agree that's not a meaningful change. It's an artiface of the model.

What happens when you use other sorts of technique is time is bend. Either it's a very short time or it's a short time or something like this. So time is discretized (sic) like this and if you don't see a large change in time, you assume time doesn't have a large effect.

The other thing to realize is that operator reliability is not solely driven by the amount of available time. For some events, realizing that the plant is operating using symptom-oriented EOPs what becomes important is the operator training and the availability of cues to the operator, procedural guidance, these sorts of things. So the time is not really material to the estimation of the probability of human error like this.

So what the Licensee did that we agree with is when there are certain causal factors they used the technique called the cause based decision tree to estimate the human error probability. For errors that were time sensitive, they used the technique called the human cognitive reliability technique. Both of these are well known human reliability techniques, but I was a little concerned about why you would pick one over the other.

MEMBER WALLIS: What sort of numbers do you get for the most significant time changes?

MR. STUTZKE: In terms of?

MEMBER WALLIS: Whether there is a significant time changes.

MR. STUTZKE: In terms of minutes.

MEMBER WALLIS: Whatever? What's the most significant time change that you came across and how different were the methods, how different were the results from different methods as to estimating probabilities?

MR. STUTZKE: Well, I can't give you a choice on the difference of methods per se because we didn't do the sensitivity study to compare one method to the other like that. The one I'm remembering is inhibiting ADS, for example. The time went down by several seconds. It's not noticeable.

MEMBER WALLIS: Went down from what?

MR. STUTZKE: I don't remember precisely.

MS. BROWN: Bill, do you guys remember you --

MEMBER KRESS: Single digits?

MR. MIMS: Yes, this is Bill Mims. The time went from two minutes to 8.5 minutes on ADS.

MR. STUTZKE: So 90 seconds. Well, I did check. The Office of Research has issued a document called the "Human Reliability Good Practices Document." There's a followup to that which is indicated on the slide NUREG 1842 --

MEMBER WALLIS: When the operator is working a simulator and they have this ten minutes to do something, do they typically do it in the first minute --

MR. STUTZKE: Yes.

MEMBER WALLIS: Or do they wait eight minutes and then do it? Does the extra time help at all?

MEMBER SIEBER: They have to have lunch first.

(Laughter.)

MEMBER WALLIS: I would think that some decisions they just make in a minute and their extra time doesn't do any good at all.

MR. STUTZKE: No, that's correct. Once they recognize the need for the action and they achieve the cue, they're going to do what they've been instructed to do.

MEMBER WALLIS: The critical thing is do they have enough time, not proportional to time.

MR. STUTZKE: That's right.

MEMBER WALLIS: If they had an hour, it doesn't mean they would make a better decision than if they had ten minutes.

MR. STUTZKE: The genesis of the time reliability correlation is under scenarios when the operators didn't know what to do. Cognitive time, we used to call it diagnosis time. They're trying to figure out currently and they may be confused. They may set conflicting parameters, this sort of thing like this.

MEMBER KRESS: ATWS is pretty easy to recognize.

(Laugher.)

MR. STUTZKE: It is rather dramatic like that.

CHAIRMAN BONACA: Okay. Let's --

MR. STUTZKE: Okay. So anyway we did look at these different HRA techniques using NUREG 1842 which is a comparison of all the known human reliability techniques against the HRA good practices documents and the techniques are being used as the Office of Research has suggested. Everything is as it should be.

Now flipping to Slide No. 6, the events that they changed all pertain to ATWS, the inhibiting ADS, lower the water level down and controlling it at top of active fuel, running slicks and backup scram. I've indicated the HRA quantification technique in parentheses here. You can see that many of them are driven by time in this one case where the cause based decision tree.

The results of all of this having learned lessons painfully before with Dr. Apostolakis, I haven't you the numbers deliberately because I feared degenerated --

MEMBER KRESS: That would have extended the discussion another half an hour.

MR. STUTZKE: Right. Are these numbers really significant or not and this sort of thing? So I will test out a new strategy. In Reg. Guide 1.200, the staff's Reg. Guide on PRA quality, the staff has defined what we call significant basic events and an event is significant if it's Fussel-Vesley importance measures greater than 005 or if it's risk achievement worth is greater than two. So it's a simple screening technique to focus on the events of the risk assessment that are important.

The bottom part of page seven I've given you events that were significant pre EPU as well as post EPU. Nothing changed. At the top, we have two new events that became significant as a result of the EPU, controlling level using HPCI/RICI and initiate depressurization upon failure of the systems. This is the consequence of not crediting enhanced CRD flow. So you make certain human error.

MEMBER KRESS: And what's significant there is the fussel-vescity and raw value.

MR. STUTZKE: That's right. Now the reason, I'll emphasize, they are significant not because their probabilities changed. It's because the structure of the model changed and that made them significant.

MEMBER WALLIS: So there are two new things that have become significant that weren't significant before.

MR. STUTZKE: That's correct.

MEMBER WALLIS: And also possible that the ones that were significant have become more significant.

MR. STUTZKE: That's right. This is accrued.

MEMBER WALLIS: So this is all very qualitative, isn't it?

MR. STUTZKE: That's right.

MEMBER WALLIS: And you refuse to give us any numbers.

MR. STUTZKE: There will be a table in the final report for 120 percent.

MS. BROWN: Yes.

MEMBER CORRADINI: So can you go back? You said something to Tom before Graham asked his question relative to the character of this. Can you restate that? I don't think I'm completely --

MR. STUTZKE: Character of?

MEMBER CORRADINI: Well, you said it's not quantitative in terms of -- I was trying to --

MR. STUTZKE: Okay. What has happened in the past is that when the staff comes and approaches this committee on EPUs and we present changes in the human error probabilities, we've made mistakes like giving you three decimal places for error probabilities or estimating changes in time.

MEMBER POWERS: But, Marty, let's be very careful. When the staff has come before the committee, they've run into difficulties with that side of the table.

(Laughter.)

MEMBER KRESS: The right --

MR. STUTZKE: The problem is there's an implied precision or accuracy to the numbers that doesn't really exist. Okay. We're looking for --

MEMBER CORRADINI: You were pointing to him?

MR. STUTZKE: -- larger changes here.

MEMBER WALLIS: Well, the staff has come before the committee with these EPUs and they've usually ended up saying that there's no technical problem. That it's all -- the only thing that changes the CDF is operator reaction time.

MR. STUTZKE: That's right and this is --

MEMBER WALLIS: -- a key thing.

MR. STUTZKE: That's true and this EPU is different because the human error is not -- doesn't have as large an impact on the change in core damage frequency as compared to the change in success criteria.

MEMBER CORRADINI: But to repeat back now what you're saying though -- That's what I'm trying to capture. This is a different character. It's not a time to make the right action. It's that because what caused the top two bullets to occur, you actually have a whole new level of effect.

MR. STUTZKE: That's right. By not being able to use the enhanced CDF flow, we have made the need for low pressure systems more important.

MEMBER CORRADINI: And therefore failure to get there is a bigger deal.

MR. STUTZKE: Becomes more important. Right.

MEMBER CORRADINI: Not big but bigger.

MR. STUTZKE: Right.

MEMBER WALLIS: So all these things get considered and then when you get to the bottom line of a change in CDF somehow all this gets quantified somehow.

MR. STUTZKE: That does get --

MEMBER WALLIS: Is this using some EPRI thing or whatever? What are you using?

MR. STUTZKE: Our quantified use in the EPRI HRA calculator.

MEMBER WALLIS: That's the way you do it. Okay. All of these things.

MR. STUTZKE: Right. I may offer a

comment, too. The EPRI --

MEMBER WALLIS: This is the one that has the George Apostolakis approval stamp on it, the EPRI one. Is that it?

(Laughter.)

MEMBER KRESS: Well, George says we'd never reviewed it and we ought.

MEMBER WALLIS: Yes, that's right.

CHAIRMAN BONACA: But he looked at it and he was impressed.

MEMBER KRESS: He looked at it and he thinks it has some good -- on it.

MEMBER WALLIS: But he keeps saying it's never been reviewed, doesn't he?

MEMBER KRESS: Yes.

MEMBER WALLIS: He's always said that.

MEMBER KRESS: Yes.

MR. STUTZKE: But it's not -- The nature of the calculations are simple. It's a very simple database type of thing.

CHAIRMAN BONACA: Excuse me. You said that the changes in success criteria are the measure contributors to the results.

MR. STUTZKE: That's my understanding.

CHAIRMAN BONACA: Okay, and that's mostly driven by the enhanced CRD system.

MR. STUTZKE: That's my understanding. Okay. PRA quality. During our review of the EPU, we became aware that the No. 1 PRA had been peer reviewed in September of 2006. You have to realize that there is no pre EPU Unit 1 risk model. The plant had been shut down for many number of years. They missed out on all the fun of the IPE. So they had to build a model starting from the Units 2 and 3, but they made substantial improvements to bring it up to the quality of the ASME PRA standard.

There was what I'll call a quasi independent review done on Unit 1. It was done by a different contractor that the Licensee had hired, mainly when they were looking at the containment accident pressure credit risk assessment.

The staff also made a one week onsite audit of the risk assessment. That was four guys full-time and I didn't participate. But we had two that are now senior level advisors. We had a guy that did all of the EPU reviews before I got involved into it. Two of the team were formally licensed SROs. So it was a pretty high powered team that went down.

And they did find some things. Our audit report is in ADAMs. The main issue seems to be documentation, trying to understand why the model is built the way that it was. In addition, the Unit 1 IPEEE review has been completed by the Office of Research. I called two weeks ago. The safety evaluation report and technical evaluation report has not been issued yet to my knowledge. The Licensee does have a formal program to maintain its PRAs as part of its maintenance role. So by these measures, the quality of the PRA seems to be sufficient for the application that we're trying to use here.

The last slide shows the actual change in the internal event risk metrics for each of the three units, both CDR and LERF. As I had alluded to yesterday, you can see that the CDF and LERF have doubled or more so. But I will also point out that if one were to plot these results onto the acceptance guidelines in Reg. Guide 1.174, it would show up in the very small change in risk.

MEMBER KRESS: That's your special circumstance, one of the flags. Right?

MR. STUTZKE: That's correct.

MEMBER CORRADINI: Can you --

MEMBER KRESS: Let me suggest to you another special circumstance like that doesn't seem to show up. You can see this one coming. Right? I would take those CDF numbers and those LERF numbers and add them up and say "Now this is a measure of the site risk characteristics with respect to surrogates or the QHOs." Now if I do that, they're well below the surrogates, you know, the CDF of $10^{-4}$ would be the latent and $10^{-5}$ would be the thing. So it doesn't raise a flag to me.

But you know I'd like to see that done. It's a simple thing. You could just have another bullet there and if these things added up to values for the site that put into question the QHOs and since I don't think they've very good surrogates for the QHOs, then it raises a flag that maybe one ought to say, "Let's have a Level 3 then to see." Even those QHOs are not requirements. We know that. But you know to me it's another special circumstance. But here we don't seem to have any problem because those are well below even if you add them up.

MEMBER SIEBER: Right.

MEMBER POWERS: They're totally meaningless.

MEMBER KRESS: Well, they don't have shutdown and even if you doubled them and say that took care of shutdown and you added in a fire risk and doubled that, they still wouldn't add up to values that would in my mind raise a concern. But I don't know if doubling it is an appropriate thing or not.

MEMBER POWERS: I have no idea. Now what's interesting is that you see peculiarities in the conditional containment failure probability drive from these numbers.

MEMBER KRESS: Yes, there's pretty high conditional containment failure problems.

MEMBER POWERS: Actually, it's pretty low compared to what you would expect for a boiler.

MEMBER KRESS: Yeah.

MEMBER POWERS: Okay. But you only have LERF. You don't have the longer term failures shown up here. So, yeah, it's just LERF.

MEMBER KRESS: Conditional includes the longer term ones. You're right.

MEMBER POWERS: Yes.

MR. STUTZKE: That's correct.

MEMBER KRESS: So this would be the early conditional.

CHAIRMAN BONACA: A question I have is for all three units you only credited CDR system enhancement after six hours.

MR. STUTZKE: That's correct.

CHAIRMAN BONACA: Why was it? If you can

explain to me again.

MR. STUTZKE: With the 120 percent EPU, there is simply more decay heat generated than the flow can compensate for in the system.

CHAIRMAN BONACA: All right. So you do not -- Okay.

MEMBER WALLIS: But it does have some effect, doesn't it?

CHAIRMAN BONACA: Sure.

MR. STUTZKE: Yes, it would have an effect. It would be beneficial -- It's always beneficial to add water.

MEMBER WALLIS: Right.

MR. STUTZKE: Even if it's not enough.

MEMBER CORRADINI: Can we go back --

MEMBER POWERS: Well, I mean it depends on where you are in the accident. If I were doing a Level 2, I can find sequences where I would just assume I didn't have that CRD flow. I'm not going to turn it off but it is going to cause me a headache because of an excursion taking place in the zirconium.

MEMBER CORRADINI: Can I ask you just a question? I want to make sure I -- So you made a point yesterday, I was pulling out your other two presentations, that the total from the cap credit looks to be essentially ten percent of the post EPU CDF. So is the other 90 percent primarily in this qualitatively characteristic change of essentially failing to depressurize? I mean let's just say that all these are totally acceptable numbers and life is good. I'm still trying to understand that 90 percent of the change is due to the fact that you failed to depressurize. Am I misunderstanding?

MR. STUTZKE: No. The 90 percent includes all types of sequences. Some of them are high pressure scenarios. Some are low pressure scenarios. Some are ATLAS driven.

MEMBER CORRADINI: So it's a whole bunch of things that aren't capped.

MR. STUTZKE: That's correct.

MEMBER CORRADINI: But you alluded to it yesterday. So now I guess I'm asking directly. How much of the post EPU CDF is related to this failure to depressurize in the time because you don't have an enhanced CRD flow?

MR. STUTZKE: I don't know.

MEMBER CORRADINI: Half of that order?

MS. BROWN: Bill, do you guys have -- want to comment on that?

MR. CROUCH: Can you repeat the question

please?

MEMBER CORRADINI: I'm trying to unravel because I guess -- so this is a little bit of just for my own understanding. There are levels of where one is concerned. If I understood this correctly from what you were answering to Tom's questions is that I'm below this magical limit of $10^{-5}$. So therefore all these deltas or these levels are below a level of concern, right, for the CDF and then 10 times lower for the LERF. So that's 0.1 and then the other point you were making yesterday was that a major fraction of the post EPU CDF is due to this qualitative failure to depressurize. So my question is how much is it.

If you had an enhanced CRD, would that go down by a factor of two? Would it go down by a factor of three? What is it?

MR. MIMS: This is Bill Mims. What we found before was we lost or gained 10 to 15 percent in CDF due to enhanced CRD flow elimination.

MEMBER CORRADINI: I see. Okay.

MEMBER KRESS: $10^{-4}$ and $10^{-5}$.

MEMBER CORRADINI: What?

MEMBER KRESS: $10^{-4}$ and $10^{-5}$.

MR. MIMS: I should say CRD elimination early.

MEMBER CORRADINI: Okay. Thank you. Then the next thing is that I wanted just to ask is because I caught the same thing. So if I take the ratio of the post EPU CDF and the post EPU LERF, that's approximately the containment failure probability.

MEMBER KRESS: Early.

MEMBER CORRADINI: Early.

MR. MIMS: Early.

MEMBER SIEBER: Conditional.

MEMBER CORRADINI: I'm sorry.

MEMBER SIEBER: The conditional.

MEMBER CORRADINI: Conditional. Thank you. So the total containment failure probability is of the order of one in four.

MR. MIMS: Actually it's closer to 60 percent.

MEMBER CORRADINI: Sixty percent. And that's --

MR. MIMS: It's the standard number.

MEMBER CORRADINI: And then Dana made the comment that that's not surprising for a BWR.

MEMBER KRESS: Some of them are around 0.8.

MEMBER CORRADINI: So how is that estimated in the Level 2? You said that quickly and

I didn't catch how it's estimated.

MR. STUTZKE: Traditionally, the way it's estimated conditional containment failure probability is one minus the sum of the intact sequences divided by the core damage frequency.

MEMBER KRESS: Each one of them is weighted by the core damage frequency for that.

MR. STUTZKE: That's right.

MEMBER CORRADINI: Okay. But the calculation -- So I will ask my question more specifically. How is the number estimated? I understand how all the numbers are estimated up to the point of CDF. From that point on, how is it estimated now?

MR. STUTZKE: For the frequency of release?

MEMBER CORRADINI: Yes.

MR. STUTZKE: All the way through in a Level 2 event consider the phenomenology and the system status.

MEMBER CORRADINI: So they will do a series of math calculations and then essentially compute what isn't failed of all the sequence.

MR. STUTZKE: That's it. Yes.

CHAIRMAN BONACA: I had a question

regarding CAP credit. You showed yesterday that it was around ten percent of the overall risk resulting from that.

MR. STUTZKE: Yes.

CHAIRMAN BONACA: And that scenario that was dominating the CAP credit issue was the Appendix R. It was the measurement of --

MR. STUTZKE: The generalization of that Appendix R scenario.

CHAIRMAN BONACA: That's right.

MR. STUTZKE: Yes.

CHAIRMAN BONACA: And now you also stated if I remember that you would not consider the possibility of failure of containment in this 70 hours, 68 hours, that the scenario lasts. I mean you assume that.

MR. STUTZKE: That's correct.

CHAIRMAN BONACA: And of course if you assume at any given time there you would lose the ability of cooling.

MR. STUTZKE: That's correct.

CHAIRMAN BONACA: So that's a critical assumption.

MR. STUTZKE: It's true and I know when we had discussed this at length under the Vermont Yankee one of the questions that you asked that I spent a great deal of time thinking about is how much credit is too much and how long is too long. And I have looked for some way to quantify that using pure reliability engineering techniques, but I need the equivalent of a failure rate of the containment following the accident and I don't know how to produce the number right now.

MEMBER WALLIS: I've a point regarding risk benefit and here you have a benefit which is 20 percent more. The risk is up in terms of LERF by a factor of 2.5 and in fact there's a bigger source term. So in terms of risk benefit although you meet 1.174, it doesn't look so good. You actually -- The risk has gone up more proportionally than the benefit.

MR. STUTZKE: No, it's --

MEMBER POWERS: It's not a way to look at those numbers. You're looking the difference are noise.

MEMBER CORRADINI: On these numbers here, Dana?

MEMBER POWERS: Yes. You can't tell the difference between those numbers.

MEMBER KRESS: You're right. You can't.

MEMBER CORRADINI: Fine. That's what I

was asking him privately.

MEMBER KRESS: They're all essentially the same number there.

MEMBER CORRADINI: Yes, that's right.

MEMBER ABDEL-KHALIK: Can I ask a question, a followup to the question raised by Dr. Bonaca? The CAP credit risk impact numbers that you gave yesterday essentially give an estimate of the increased risk if the operator were to fail to take the action that is specified procedurally to respond to Appendix R fire.

MR. STUTZKE: That's correct.

MEMBER ABDEL-KHALIK: Now the question is how about the opposite scenario. What if the operator takes that action too early when it's not needed? Where is that included in the risk assessment?

MR. STUTZKE: That's not included in the risk assessment.

MEMBER POWERS: That would be a narrow commission and it's not included.

MEMBER KRESS: A commission. You don't do that in PRA.

MEMBER ABDEL-KHALIK: But procedurally the operator is allowed to take that action and the operator takes --

MEMBER POWERS: How would he get into that scenario?

MEMBER ABDEL-KHALIK: There are indications of a fire that would automatically make the shift supervisor grab that piece of paper that is related to that particular procedure and if the shift supervisor were to initiate this drywell coolers termination action early or when it's not needed where is that action considered in the various scenarios?

MEMBER WALLIS: Would it over pressurize the drywell. Is that right?

MEMBER ABDEL-KHALIK: Yes.

MEMBER SIEBER: Yes, it does.

MEMBER POWERS: I guess I don't follow because if there were no fire and he took the action how does he get in trouble?

MS. BROWN: There's no --

MEMBER WALLIS: He knows there's a fire. He just takes the action too soon.

MEMBER ABDEL-KHALIK: Right.

MEMBER POWERS: Again, how does he get in trouble?

MEMBER ABDEL-KHALIK: That's what I wondered.

MS. BROWN: Is the question is there a too soon for this action.

MEMBER ABDEL-KHALIK: Yes, in a sense that there are certain indications --

MS. BROWN: Can you turn the drywell cooler on?

MEMBER ABDEL-KHALIK: The procedure says that there are certain sort of indications that have to be recognized by the shift supervisor to enter that leg of the procedure.

MS. BROWN: Right and they have conclude --

MEMBER ABDEL-KHALIK: And the question is what if the shift supervisor takes that action too early.

MS. BROWN: And Mr. DeLong.

MR. DeLONG: This is Rich DeLong, Site Engineering Manager for Browns Ferry. The answer is containment cooling is never credited in our analysis --

MEMBER SIEBER: For anything.

MR. DeLONG: -- for determining containment over pressure. So the act of securing containment ventilation cooling early has no effect on the analytical containment analysis.

MEMBER ABDEL-KHALIK: Thank you.

MEMBER CORRADINI: Can I? Dana, I was asking Tom privately but you kind of answered it which is the wiggle in all these numbers given the uncertainty is in the noise. So I would look at the exponents. So the way you've answered, I guess you originally answered Tom's stuff, is that given the fact that you're an order of magnitude and in some cases two orders of magnitude below a worry level, that's the confidence, that's where you gain the confidence that --

MR. STUTZKE: That's right.

MEMBER CORRADINI: Fine. Thank you.

CHAIRMAN BONACA: Any other questions on the PRA?

MEMBER WALLIS: Well, it's not just noise. There have been increases in risk. It's not as if you were ignore completely the number. One is bigger than the other. You shouldn't too seriously by how much but it gives us an idea of an increase.

MEMBER KRESS: -- risk is increasing by 60 percent.

MEMBER POWERS: Sixty percent of vanishing small is still vanishing small.

MEMBER KRESS: That's right. That is right. That's why we say it's not to be of a concern.

MEMBER CORRADINI: I mean to put it a different way, Graham, the reason that I'm curious about the ratio is that you're telling me that with all the effort on containment it still fails 80 percent of the time when you need it. I mean to me that's the thing that worries me most about the numbers personally.

MEMBER WALLIS: What's the contention for in that case?

MEMBER KRESS: And it has to go through the suppression --

MR. RUBIN: Excuse me. This is Mark Rubin from the staff. This is not 80 percent of the time where it's challenged from design basis accidents. This is well beyond design basis and severe accident space. I'll just give that perspective too. Much lower frequency.

MEMBER CORRADINI: That's correct. I agree.

MEMBER WALLIS: Isn't that why you need it?

MEMBER CORRADINI: That's why I --

MEMBER WALLIS: There's no sense in protecting the public against DBAs because they don't really do anything. But really you would want to protect them against the big accident.

MEMBER SIEBER: It's defense-in-depth for DBAs.

MEMBER POWERS: It seems to me before I get too wrapped up in what the conditional containment failure probability is remember if you ADS this system you have about 10,000 different low pressure water sources in here. I have once seen a list for Browns Ferry No. 1 of all the low pressure water sources and it went on for about two or three pages.

MEMBER KRESS: That's why the CDF is small.

MEMBER POWERS: That's why the CDF is really small on these units.

MR. RUBIN: Mark Rubin again. Between BWRs and PWRs, obviously you'll see the inverse where you have perhaps in some cases a higher core damage frequency but a comparatively lower conditional containment failure probability. So the net result is essentially a wash. But as Dr. Powers pointed out, the ADS capability makes available to the plant operators many additional opportunities to provide the K heat removal and inventory makeup.

MEMBER POWERS: Yes. Where you get in trouble with these units is when you hang on in a scenario until you deplete the batteries or other sources and you can't ADS. Those are the classic sequences to get you in trouble with boilers.

CHAIRMAN BONACA: Any other questions specific to this? I thank you for the presentation and what I would like to do is I would like to break now and then come back into session and simply ask your views individually, what you think about what you've heard today, your concerns are, and also your recommendation to what we should provide the full committee in two weeks.

MS. BROWN: Dr. Bonaca, before you do that, I think there was one additional question in the containment accident pressure that Mr. Lobel have come over to answer.

MEMBER ABDEL-KHALIK: Yes. I just wanted to -- You pointed to the documents where the calculations for the suction, the pressure drop in the strainers and -- But I think that that was a question for information.

MS. BROWN: Rich, did you --

MR. LOBEL: There is a -- What I --

MEMBER BANERJEE: Which document was that?

MR. LOBEL: This is Richard Lobel from the staff. What I have is a November 25, 1998 letter from

TVA that describes their debris considerations for the strainers that's publicly available and I was only able to get the answers to some questions that I asked as part of this review that describe in words, but not in calculations, what they do. But unfortunately the pages that I have are marked proprietary even though I don't think any of this is really proprietary. It was just from a proprietary submittal.

So somewhere in ADAMS, there's a nonproprietary version. But I can give you that or --

MEMBER BANERJEE: I can have the proprietary version.

(Off the record discussion.)

MR. LOBEL: I made a copy of the proprietary and I made a copy of the other letter too.

MEMBER KRESS: We're allowed to see that.

MR. LOBEL: I know. It's just inconvenient to carry it around I would imagine. That's all.

MEMBER BANERJEE: However if you say it's just qualitative that's not what I'm looking for. I want to see the quantitative.

MR. LOBEL: The November 1998 letter has calculations.

MEMBER BANERJEE: Calculations.

MR. LOBEL: Yes.

MEMBER BANERJEE: It has things like their approach.

MR. LOBEL: But that was done awhile ago. So the number probably aren't going to be the same as the numbers exactly that are used in the power uprate, but the method description and all that is going to be the same. And it does have calculations. It shows the steps that TVA went through.

MEMBER BANERJEE: We'll start with that and then I'd like to see where --

MR. LOBEL: Like I said though before when we were doing this review, this was considered as something that had been resolved. This was talked about at the time that the larger strainers were put on Units 2 and 3 and that's when most of the correspondence is and for this review the only question was have you made any changes from what you previously submitted and TVA not only answered the question, but they provided a description again of the head loss and the other parts of the calculation, the other assumptions for other types of debris and that kind of thing. But this wasn't much of an area of review for the power uprate since it had already been reviewed by the staff.

MEMBER WALLIS: Rich, can I ask you a question?

MR. LOBEL: Sure.

MEMBER WALLIS: As a preamble to this allowing containment over pressure, there was a statement that if the design cannot be practically altered. Now this plant has been in a state in which it could have been altered for decades. How do you justify that the design couldn't be practically altered and therefore we have to allow containment over pressure?

MS. BROWN: Bill, did you guys want to answer that question?

MR. CROUCH: In order to significantly affect the MPA site calcs you would have to raise either your water level in containment which means that I would have to raise the entire containment which is not practical or I'd have to somehow lower the pumps.

MEMBER WALLIS: Well, you could have a bigger pipe. You have less friction in the pipe.

MR. CROUCH: The pipe is not a major portion of the pressure drop.

MEMBER WALLIS: Where is the pressure drop? Is it all just in the head?

MR. CROUCH: It's the elevation head.

MEMBER WALLIS: Oh, there's elevation.

MR. LOBEL: Yes.

MEMBER WALLIS: So the pressure drop part is negligible because I didn't see any breakdown of the contribution. There was simply an equation that says that you had upped these things. But I didn't see the breakdown. Okay.

MEMBER BANERJEE: That's what I'm asking for.

MEMBER WALLIS: Have you assessed this? Has the staff made an assessment that the design could not have been practically altered? Change the pump in some way or something?

MEMBER CORRADINI: The answer yesterday I think -- I think Professor Wallis really needs to get this background. We were asking you yesterday and you went through a list of things that you considered doing that you can't do given the fact either time or expense. I guess --

MEMBER WALLIS: To me he has gone through this and it's been resolved.

MEMBER CORRADINI: Yeah, but I think it's well worth going over though.

MR. CROUCH: You obviously cannot raise

the containment. It would require raising all the floors of the reactor building and you cannot lower the pump effectively because the pumps right now sit on the base mat of the plant. So you have to be digging down through the base mat.

Increasing the size of the suction piping, that's not a major portion of the pressure loss. So it would not --

MEMBER WALLIS: Is there any pressure loss by friction?

MR. CROUCH: There's some.

MEMBER SIEBER: You can't make up by changing the pipe size the amount that you need.

MR. WOLCOTT: J.D. Wolcott, TVA. The --

MEMBER WALLIS: You can't change the pump in some way. You can't change the induction to the pump so that --

MEMBER ABDEL-KHALIK: How about raising the tech spec limit on the level?

MR. CROUCH: You couldn't raise it that much.

MEMBER ABDEL-KHALIK: Right now the tech spec level on low level is how far? Is it five feet about?

MEMBER SIEBER: Do you mean the -- level?

(Several speaking at once.)

MR. LOBEL: You have to be careful changing the level of the suppression pool because you start to affect the hydrodynamic loads calculations. They are sensitive to the elevation of the water in the suppression pool.

MEMBER ABDEL-KHALIK: But what is the range of acceptable level? You have a minimum level and you have a maximum level.

MR. CROUCH: The tech spec band is only six inches. It's pretty close.

MEMBER SIEBER: And you need over six feet.

MEMBER CORRADINI: Right. That's the thing, Graham, that I wanted to --

MEMBER WALLIS: You couldn't go to a Zilzer pump? You couldn't go to Zilzer and say "Redesign the impeller so that it cavitates -- less prone to cavitation."

MEMBER SIEBER: Now with the head that you need.

MEMBER WALLIS: I'm not sure. I think you can. There are pumps that are less prone to cavitation but they don't produce such a low pressure locally so that you cavitate.

MEMBER BANERJEE: Well, we don't know whether that can be done or not. But we haven't --

CHAIRMAN BONACA: You've been told.

MEMBER BANERJEE: You've been told that's not been done.

MEMBER SIEBER: Usually when you design a pump that will tolerate real low MPSH it's very large in diameter.

MEMBER CORRADINI: Circ water pump.

MEMBER SIEBER: Yes. And one that's large in diameter won't fit down in the casing because this is a deep draft pump.

MEMBER WALLIS: Okay.

CHAIRMAN BONACA: What I would like to do is to complete this portion, take a break, because Mr. Dyer I've been told will come here to wrap the staff presentation to the committee. So before we go to our commitments, we can hear what he has to say to us and he'll come around 3:50 p.m. So the timing is good. I think let's take a break, get back here between 3:45 p.m. and 3:50 p.m. We'll listen to him and then we can do what I said. Put on the table our views and the recommendation of the presentation. Off the record.

(Whereupon, at 3:31 p.m., the above-entitled matter recessed and reconvened at 3:52 p.m. the same day.)

CHAIRMAN BONACA: On the record. We'll get back into session and we have Mr. Dyer who is coming here to give us some conclusion statements of the presentation for Browns Ferry power uprate.

Mr. Dyer: Thank you very much, Dr. Bonaca. I guess I want to thank first of all thank the subcommittee for working on this important licensing issue here in the month of January and accelerating your review schedule to support this licensing schedule that we're on. We really do appreciate it recognizing the additional work and certainly this 105 percent uprate is a critical part of the licensing package for the Browns Ferry Unit 1 restart activities that we're undertaking and recognizing that it will go before the full committee in a couple weeks in February.

You know, recognizing too, I just left Bill Travers and the other regional administrators are meeting with Bill Kane right now. But it is very dynamic time right now with the schedules for the Browns Ferry Unit 1 restart and the systems turnovers and completing the licensing action and your support is critical to that.

Recently, the schedule has changed. We heard about that right before the Commission meeting where the outage TVA chose for safety reasons in the shared control rooms in Unit 1 and Unit 2 at Browns Ferry to delay the Unit 1 restart activities until after they completed the Browns Ferry Unit 2 refueling outage. But I think it's important that we proceed through the licensing actions and then my team is heading up here.

I think it's in the best interest of safety when you get all the major modifications approved and the licensee has a month or two to prepare for their restart activities knowing exactly what their licensing basis is going to be. It's always a concern to me when we sign off on a licensing action and a week later they are preparing for restart and whether or not everything has been double-checked and that and the training that's been going on is the anticipation of what the staff is going to approve and the last minute conditions we may put on a license action. So I think the schedule and the effort that we're putting in now is still going to be beneficial going forward.

Again, to that end, we really aren't clear yet what the schedule is for the extended power uprate. I know that the safety evaluation that you reviewed and a number of the challenges that the staff relayed to me during the breaks involve a lot of the analyses that we did for the 120 percent that the Licensee is requesting to credit for the 105 percent safety evaluation. So I think we're in a good position for working to closure on those commensurate with 120 percent extended power uprate and I believe TVA is still planning sometime in the future, but not on the same schedule that we had originally thought.

With that, I appreciate the effort that the subcommittee has made. I understand there was a very healthy discussion and, Dr. Bonaca, I'll turn it over to you for concluding remarks and feedback.

CHAIRMAN BONACA: I thank you. Our plan right now is actually to go around the table and get individual member views as well as recommendations, so two things, one views on what we heard, what the concerns are and, second what we should bring to full Committee in two weeks, what kind of presentation, what are the issues that we should dedicate ourselves to and yet we will have only a couple of hours during that meeting. So you are welcome to stay here so you can listen to these views.

I will start then around the table with

Jack.

MEMBER SIEBER: Okay. I guess I have just two comments to make. Our review has really been a review of the 120 percent EPU application with the exception of the core design. In the interest of efficiency, I think that we should consider that if we give approval or to recommend an approval for the 120 percent work that the analysis that's been done with the exception of the core design that we not review that again because it's really been presented. We have commented on it and analyzed it and so forth. On the other hand, a license for an extended power uprate to 120 percent would require our review of the fuel and core design prior to the staff taking that action.

I thought over all that -- The SER and the application are in pretty good shape. Some issues I think were done better than others, but I found no issues that actually violated the regulations.

On the other hand, I do have an issue that is of concern to me and I would refer to TVA's handout on page N-8 which is a graph that looks like this and it depicts the containment over pressure allowance that needs to be given and if I look at that graph and interpret it, the center line on that which is purple I guess, unfortunately I'm color blinded, I can tell red, yellow and green but purple is a tough one for me, but it's the middle one, it seems to me that the required containment over pressure allowance is larger and longer than any that we have ever approved.

According to this graph, it's almost 24 hours in length and it's 3 psi which is 6 feet a head from an MPSH standpoint. I don't think that would be easy to overcome by plant modifications or procedural changes and the troublesome thing is that it sort of flies in the face of defense-in-depth because when you do that you make the one barrier of the three dependent on another barrier and that barrier that becomes dependent is the fuel cladding and it's dependent on containment integrity. If containment integrity fails, you can't cool the core and the cladding will fail and that's against the precept of defense-in-depth as far as I'm concerned.

If you look through the regulations though, there is no codification that says that you have to do that. And so it's not clear to me whether that dependency is allowed or not allowed. On the other hand from an engineering standpoint, it's not a great idea. I would be satisfied and much more comfortable with a shorter period and a lower head because then there will be some hope that the pump would ride through a cavitating period without destroying itself.

But I think 24 hours is really stretching it. And so while I won't say that I vote against granting the EPU under the condition of also granting containment over pressure exemption, I would worry about it.

CHAIRMAN BONACA: What about the sequence for Appendix R? Is it the one -- What about the Appendix R sequence? That's even longer. That goes --

MEMBER SIEBER: The one where you can't get it at all. Right?

CHAIRMAN BONACA: Right.

MEMBER SIEBER: Well, I think that one is a concern too.

CHAIRMAN BONACA: Because it depends entirely on the containment capability of holding pressure.

MEMBER SIEBER: Yes. On the other hand, if you stick to the code allowances, then you really probably cannot make it. I think it would take some more thought and analysis to do that. On the other hand, I don't feel totally uncomfortable because we know that within the code allowances there is factors of strength and margin that's pretty big. On the other hand, it's not allowed and you aren't supposed to use margin in that way. But I think that needs additional analysis and additional thought.

CHAIRMAN BONACA: What would you see important for representation to the full committee?

MEMBER SIEBER: I think the containment over pressure and the Appendix R are the key issues.

CHAIRMAN BONACA: Yes. Okay. Thank you, Jack. Said.

MEMBER ABDEL-KHALIK: I agree with the comments made by Jack. I would like to sort of as a side issue to that, I'd like to add one concern which is what comes in Appendix R having the operator required to take sort of a counter intuitive action by terminating drywell coolers and to me in a plant like Browns Ferry that may create an operator mind set. See a fire. Terminate drywell cooling and that is not sort of in an integral is not the optimal action to take.

CHAIRMAN BONACA: And the presentation to the committee.

MEMBER ABDEL-KHALIK: I think the MPSH calculation should be much more clearly and in detail elucidated. I also would like to see the stability analyses at 120 percent power. The Applicant indicated that the analysis at 105 percent power are being performed at this time and that analyses at 120 percent power were done in the past. I haven't seen either one of them and I would like to see them.

CHAIRMAN BONACA: Okay. Thank you. Sam.

MEMBER ARMIJO: Well, I agree with Jack's and Said's comments on the over pressure issue and on the responses to fire. I think that's hard to swallow. You know, it just seems like it's not the right thing to do. I was very impressed with the plant with all the changes and improvements in the materials that have gone into the plant, clearly a massive investment and all for the better modern materials, a commitment to apply the best water chemistry to avoid the problems of materials degradation that we've had in the past.

I'm not totally convinced that the steam dryer issue is solely limited to failure due to fatigue or vibration. I still think -- I still have some concern that IGSCC can also be affected by power uprate through environmental change, not necessarily vibration, but the chemistry changes and the amount of water that can get into the steam dryers. We might have to be seeing some problems with dryers due to more IGSCC than expected. Other than that, I think as long as we get to review the core and fuel design for 120 percent, I think the issues that had already been reviewed are satisfactory.

CHAIRMAN BONACA: Okay. Thank you. And again presentation pretty much you agree on that focus. Dana?

MEMBER POWERS: I think you should start off your presentation in front of the full committee with a very clear, crisp introduction of who's done what to whom with respect to Browns Ferry because 105 license extension, all those things get wrapped up and it gets very confusing and you just need a very crisp definition of that.

In general, I find things are in pretty good shape. We have a couple of areas that I think create generic concerns for us more so than specific things for Browns Ferry. We do have this net positive suction head and as the committee has often said, requests for containment pressurization should involve small amounts of pressurization for short periods of time and be rare.

In general for most cases, that is the case here for Browns Ferry. They have introduced this relatively new accident sequence which is really an

Appendix R sequence and I myself need to go back and look at this. I think there's a way out of this woods on the Appendix R sequence and we ought to pursue that one. But then the question comes up, what about all the others that we've not looked at this Appendix R sequence? Have we any problems there? Probably not because many of those are fairly small cores.

Similarly we need a nice clean, crisp what do we know now about the steam dryer issue, not just for Browns Ferry, but generically and then what are they doing at Browns Ferry. I think they're in very good shape. I think they have a robust steam dryer here that it's just not in the same league with the situation at Quad Cities and elsewhere. But I think the committee has to have a very clean, crisp, -- and I'm talking about 15 minutes of here's what we know, here's what the status is, here's where we're going.

I think that the members not present here will be insistent on hearing the human error analysis and the CDF results. The staff is getting experience to presenting those and to the absent members and their particular peccadillos in this area. But I think we have to endure that because they'll expect it. I don't think there's any problem there.

I do think we have a generic issue on the seismicity issue that we need to think about how to communicate to the commission about this issue that's coming up because seismicity has changed. I don't think there's any problem at Browns Ferry. I think they're in one of those seismic-least active areas and whatnot, but I think in general we have to communicate to the commission and make sure they're aware that our expected seismicity of the eastern United States is just different when most of these plants were licensed and it will have impacts in the future as we move to licensing. It's one of those things that we're just going to have to wrestle with on how we communicate not in the context of Browns Ferry but in the --

CHAIRMAN BONACA: More generic.

MEMBER POWERS: Yes. I think Browns Ferry deserves a lot of credit because they've alerted us to some generic issues, none of which impact them, but which impact the general enterprise.

As I said, I think they've done -- It's a pretty impressive job considering all they were trying to do and similarly I congratulate Mr. Dyer and your staff for undertaking a review that seems to occupy many shopping carts here. A heroic effort on all people's parts. I'm quite impressed basically. Again, discuss MPSH, steam dryers, human error and again I would begin all these things with very crisp introductions on what the status of the world is and then a very brief discussion of what the status is on Browns Ferry because I think these are pretty well -- I think we know what the situation is.

CHAIRMAN BONACA: Thank you.

MEMBER POWERS: The Licensee may be the right one to say what -- who has done what to whom here on this application because he might be able to put it in a good context of his overall strategy. Business gets awfully confusing at times.

CHAIRMAN BONACA: Graham.

MEMBER WALLIS: I would like to add a few things that haven't been said so far. Unfortunately, I wasn't here for the Browns Ferry presentation yesterday because of the weather. I thought the staff did a pretty good job of defining their conclusions in the oral presentation when we questioned them and the SER itself, we have worked over the years to try to get the SERs to stand on their own as a document that provides rationale for decisions and this one seemed to have slipped back a bit to the old format which was the staff looked at the application and concluded that everything was okay. It really helps if you cite the criteria used, give some numbers and give some sort of confidence that this decision was reached in a rational way and not just whimsically and it doesn't take much effort to do that. I think this SER slipped back a bit from what this committee has tried to make these SERs look like over the years.

Now in the pump containment over pressure question, when we wrote a letter on Vermont Yankee, we mentioned the efforts of that applicant to look at the uncertainties and the various phenomena that affected the suppression pool temperature and the containment pressure and that was very helpful. In fact, some of us wrote, had a comment, saying what we would like to see is a realistic analysis of containment pressure and suppression pool temperature with uncertainty and this might well show that when you did it that way the probability of having to ever need containment over pressure was very small.

Whereas, what's done here is we have a conservative suppression pool temperature which is probably too high, it doesn't often occur. We have a very conservative containment pressure which is far lower than is really there and when we look at these, it looks as things are really bad for the pumps. It really would help if we had a realistic analysis with uncertainties which would probably show that all this concern about needing so much pressure for so long really is right at the extreme end of some probability distribution and we really shouldn't be focusing on that. We should focus on what's likely to happen. What's the probability of something going wrong rather than making it look as bad as you do if you look at the worst possible conservative case for everything.

CHAIRMAN BONACA: Just one note on this issue. You weren't here when we heard that the BWR ERG is developing in fact some kind of methodology to do that.

MEMBER WALLIS: That would be good.

CHAIRMAN BONACA: That would be good. But I think it's a very good observation again. I think it's important that we remind the recommendation was in the letter and I think we still need something.

MEMBER WALLIS: I would like to preserve to encourage the staff to look for that in the future.

CHAIRMAN BONACA: Right.

MEMBER WALLIS: I think that the whole committee has to as has been mentioned by one of my colleagues think about what we meant when we said rarely and low pressure for a short time and whether we really meant what we said at that time. We said it twice. We reiterated it and certainly 60 something hours or however long it is, it seems to be 69 hours, it doesn't seem a very short time to me.

CHAIRMAN BONACA: Okay.

MEMBER WALLIS: The pinnacle issue seems to this containment over pressure issue. Otherwise, there isn't much that came up.

CHAIRMAN BONACA: Michael.

MEMBER CORRADINI: Want me to go? Okay. So most of the things have been said. I just want to emphasize two things. I'm new to all this. So I guess precedent has to somehow play a role. In the January 2006 letter about Vermont Yankee it states in the discussion that for the LOCA scenario the maximum containment pressure credit is 6 psi for 56 hours and for ATWS 2 psi for one hour. So if it's good for Vermont Yankee, logic says it ought to be good enough for Browns Ferry. But I personally am still concerned about it and I think what Graham said relative to there is a band on N-8 and N-10 from the Licensee's presentation. They make a point of saying that this is the lower bound of containment pressure and probably pressure is higher. I think what was said that we'd like to know how fat that band is versus that it's just a line is important.

But I don't think Browns Ferry is too far different than what I read to be the case for Vermont Yankee, at least, if I understand the letter correctly.

MEMBER SIEBER: Yes. On the other hand, the documents presented to us don't show any of that. So I can't draw that conclusion until they put it on the record.

MEMBER CORRADINI: Right. The second part of it, I guess, is that I think I would emphasize what Said said relative to Appendix R. If there is a way around it, that's fine. The way it looks that actually is more troubling relative to how close you are between the pressure and what is required to make things work.

The other thing is again to emphasize relative to a technical issue, I think one of the consultants for the Licensee did a nice job of explaining what they appear to be the root cause as being an acoustic mechanism. I think that's important and I also think there ought to be some sort of experimental empirical way of determining that as you go up into power ascension beyond 105 or else that will be a concern since this is a big unit.

I think that's basically -- in terms of presentation, I think everybody else has told you how to present it or asked how it could be presented.

CHAIRMAN BONACA: Thank you. Good. Tom.

MEMBER KRESS: I would like to think that TVA done a very good job of refurbishing the unit and getting ready for the restart and I didn't see anything particularly that would prevent the power uprate. I think they seem to meet all the requirements very well and the staff I think did a good job of reviewing that. I'm particularly glad to see that TVA has plans for the startup testing that they have. I think it's a good idea for Unit 1 and I would also like the concept of going up in increments and monitoring the effect on the steam dryer loads. So I think those are all good things.

The one thing I was left a little unsatisfied with was the basis for the vendor's pump curve for the remaining life time versus net positive suction head with flow as a parameter. I would just like to know how those curves were developed and more about the background on them. Of course, that's the vendor's thing but I don't know. Perhaps either the staff or TVA should understand them a little more if we're going to use them and I'd like to see more on that.

I really support Graham Wallis' comment on it would really be nice to have a realistic analysis with conservatisms on the net positive suction head. I think that would make the issue go away. I never did like our comments on the short time, low pressure for short time, because those sound like vague requirements that we hear all the time on other things and they're hard to define. I think if we had a realistic analysis with uncertainties like we hear are possibly being developed we'd would have a way to look at that and say "That's not a real problem." So that, I'm anxious to see somewhere down the line. I think what's done already for Browns Ferry is probably sufficient.

Similarly, I think in general I'd like to see more uncertainties on the risk parts of these. I know this is not a risk inform but I would like to know what the uncertainties are on the deltas, the ΔCDF and ΔLERF and as I pointed out to Marty, I think one of the flags for maybe even bringing in to question the adequate protection ought to be the full site risk and just to get a flag on that, I would add up the core damage frequencies and the LERFs and compare them with the surrogate values that we think are good surrogates for the latent and for the QHOs.

So I think it was a good job all around

and the staff's and TVA's parts.

CHAIRMAN BONACA: Thank you. My comments are the following. I share some of the concerns with MPSH. That's my central concern. The reason why I view it as significant is because it really is different from Vermont Yankee. Vermont Yankee, we had 6 psi for 50 hours, but once we removed some conservatism there was no further need for credit. Particularly, they had no need credit even without the best estimate evaluation, simply remove the conservatism. Then no need for credit for back pressure.

Here both in short term and long term, you removed some of the conservatism but you still need credit for back pressure and particularly the sequence that has to do with Appendix R that is up to 9.6 psi for a long time and again if you remove some of the conservatism, you still need back pressure. So we are stretching the envelope in a way and I agree that the statement we made, you know, short time and small amount is of our own making but I think it was a communication that I think this is being challenged by some of this analysis.

The other thing that troubles me somewhat is that the contribution to core damage frequency resulting from this specific sequence of Appendix R is small. It's 10 percent of the overall risk as presented. However, it fully depends on the ability of containment to maintain containment isolation. If you lose that containment, that flies out the window. It just simply is dependent on an assumption that hopefully will be there, but simply you have to count on the containment to be available for days to provide the back pressure necessary for the scenario to evolve the way that we saw. So I think it's somewhat more severe than what we had.

Now I also agree with the views of Dana that this may be generic at some other plants too and we haven't seen that before Vermont Yankee. It doesn't mean it wasn't there. This is my major concern and I think that should be the focus of the presentation to the rest of the committee.

I think in general there has been a lot of work been done clearly and I don't think we have seen in the SER the best of what the staff has provided. I mean the staff has spent a lot of time on the 120 percent evaluation and then they had a very short time to collapse it down to 105 percent.

So I think that I am pleased that we have a good testing program. I think that the plan to deal with the dryer is a good plan. So I don't see other issues that are significant for us to make a determination.

But again, my point is that we need a crisp presentation of the back pressure issues. The SER doesn't really describe these scenarios. It only describes the short term scenarios in detail. The rest is -- I have to go back to tables in the calculations to find out what the results were and that concludes my remarks.

CHAIRMAN BONACA: Thank you. With that, any other comments from the members? Any views or comments from the public? If not, I will adjourn the meeting.

(Whereupon, at 4:24 p.m., the above-entitled matter was concluded.)

## CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on
Reactor Safeguards
Power Uprates
Docket Number: n/a
Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Eric Mollen

Eric Mollen
Official Reporter
Neal R. Gross & Co., Inc.

# Risk Evaluation

## Review Details

Primary Reviewers:

Martin Stutzke PRA Licensing Branch A

Steven Laur

# Unaffected PRA Elements

Risk Evaluation

- Initiating event definitions and frequencies
- Component reliability data
- Human reliability analysis - pre-initiator events and most post-initiator events
- Quantification method
- Level 2 PRA
- External events (no new vulnerabilities)
- Shutdown risk (no EPU-related issues)

# Affected PRA Elements

Risk Evaluation

- Success criteria
  - Enhanced CRD flow
  - MSRV operation during ATWS
  - CAP credit to provide adequate NPSH to the CS and RHR pumps
- Accident sequence delineation (event trees)
- Systems Analysis (fault trees)
- Human Reliability Analysis - some post-initiator events

# PRA Success Criteria

## Risk Evaluation

- Licensee used MAAP to re-evaluate
- Enhanced CRD system operation:
    - Unit 1: not credited (limited CDF benefit)
    - Units 2 & 3: only credited after first 6 hours
    - Largest CDF and LERF impact
- MSRV operation during ATWS (all units):
    - Pre-EPU: 9 of 13 must open
    - Post-EPU: 11 of 13 must open
    - Very small CDF and LERF impact

# Human Reliability

## Risk Evaluation

- Identification of affected human failure events (HFEs):
  - Considered how much the EPU reduced the time available for operator response
  - Considered how the available time affected the estimation of the cognitive error probability
  - Recalculated using the EPRI HRA Calculator:
    - Cause-Based Decision Tree (CBDT) used when specific causal factors are judged to be more likely to drive the probability rather than time constraints
    - Human Cognitive Reliability (HCR) used for time-sensitive errors
    - Approach consistent with the HRA good practices document (NUREG-1842)

# Affected Post-Initiator HFEs

Risk Evaluation

- All affected human failure events (HFEs) pertain to ATWS:
  - Inhibit Automatic Depressurization System (CBDT if RPV is unisolated; HCR if RPV is isolated)
  - Lower water level and control at top of active fuel (HCR)
  - Initiate Standby Liquid Control System (HCR)
  - Backup scram (HCR)

# Post-EPU Significant HFEs

## Risk Evaluation

- HFEs that became significant as a result of the EPU:
  - Control level using HPCI/RCIC
  - Initiate depressurization
- Other significant HFEs (these were also significant prior to the EPU):
  - Inhibit ADS during ATWS*
  - Recover/maintain level above active fuel during ATWS*
  - Manual control of LPCI and CS
  - Align wetwell vent path
  - Initiate SLCS*
  - Achieve SP cooling
  - Defeat MSIV interlock during ATWS
  - Manual scram*

* modified to address EPU impacts

# PRA Quality

## Risk Evaluation

- Unit 1 PRA was peer reviewed in late September 2006; results not submitted for consideration. However:
    - Unit 1 PRA was built from the Units 2&3 PRAs, whose peer review results have been examined by the staff
    - Unit 1 PRA upgraded to meet ASME PRA Standard
    - Quasi-independent review done on Unit 1 PRA
- Staff made an one-week, on-site audit of EPU-related PRA elements
- Unit 1 IPEEE review completed, but not yet formally issued
- Licensee has formal program to maintain its PRAs (part of Maintenance Rule program)

# Outcome

## Risk Evaluation

- Internal events risk metrics:

| | Change in CDF | Post-EPU CDF | Change in LERF | Post-EPU LERF |
|---|---|---|---|---|
| Unit 1 | N/A | 1.8E-6 | N/A | 4.4E-7 |
| Unit 2 | 1.3E-6 | 2.6E-6 | 1.4E-7 | 3.9E-7 |
| Unit 3 | 1.5E-6 | 3.4E-6 | 1.8E-7 | 4.5E-7 |

- Causes of the risk increases:
  - Reduced credit for enhanced CRD flow (largest effect)
  - CAP credit (moderate effect on Unit 1 only)
  - Increases in post-initiator HFE probabilities (small effect)
- During its review, the staff has not identified any “special circumstances” that rebut the presumption of adequate protection afforded by compliance with the Commission’s regulations.

# Human Performance

Safety Evaluation Section 2.11

Primary Reviewer:
Kamishan Martin

Operator Licensing &
Human Performance Branch

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# Human Factors Engineering Evaluation

- Areas of Review
  - Procedures, training, and human system interface design features related to operator performance
- Purpose
  - Assure that the proposed Power Uprate does not adversely affect operator performance

# Acceptance Criteria

**Human Performance**

- Regulatory Criteria
  - Matrix 11 of RS-001
  - 10 CFR 50.120
  - 10 CFR Part 55 (Operators' Licenses)
    - Operator Licensing
  - Generic Letter 82-33
    - Supplement to TMI Action Items
  - SRP Chapter 18.0
    - Human Factors Engineering"

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# Standard Areas

Related to Effects of EPU

- Emergency and Abnormal Operating Procedures
- Operator Actions Sensitive to Power Uprate
- Control Room Alarms, Controls, Displays
- Safety Parameter Display System (SPDS)
- Operator Training and the Control Room Simulator

# Power Uprate Effects

## Emergency and Abnormal Operating Procedures

- Changes consist of revisions to numerical values
- Changes acceptable
  - No new procedures or changes to operating or accident management philosophy required

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# Power Uprate Effects

## Operator Actions

- No new operator actions in the EOIs and AOIs
- No change in actual time it takes the operator to perform actions from initiation of action to completion
- No changes in operating philosophy or the accident mitigation philosophy

# Power Uprate Effects

## Operator Actions

- Four manual operator actions are credited in safety analyses
  - Initiate suppression pool cooling
  - Initiate drywell spray
  - Standby Liquid Control system injection
  - Required start time for containment atmospheric dilution (CAD) system initiation

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# Power Uprate Effects

## Operator Actions

- Required start time for CAD system initiation changed only for DBA-LOCA Combustible Gas Control
  - The available time to initiate changed from 42 hours to 32 hours (based on post-LOCA production of hydrogen and oxygen)
  - No change in actual time for operators to initiate the CAD system which remains 5 minutes

# Power Uprate Effects

## Operator Actions

- Acceptability of Changes to Operator Actions
  - The staff finds that the operators will be able to successfully accomplish the actions required to support the proposed EPU

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# Power Uprate Effects

## Control Room Alarms, Controls, Displays

- Setpoints changed
  - Several RPS alarm setpoints changed
- Instrumentation and operator aids
  - Labels, sketches, and markings posted in control room will be modified
- Completion of operator training will be verified as part of modification closure process

# Power Uprate Effects

## The Safety Parameter Display System (SPDS)

- Units 2 & 3
  - Recalibration of input/output points, changes to displayed point constants, and changes to the EOI limit graphs
- Unit 1
  - SPDS installed with the same design, intent, and information presented as system in Units 2 & 3
- No effect on EOI execution

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# Power Uprate Effects

## Operator Training Program and Control Room Simulator

- Changes to parameters, setpoints, instrument scales, procedures
- TVA identified & committed to conducting necessary additional operator training and startup test procedures required for EPU conditions

# Power Uprate Effects

## Operator Training Program and Control Room Simulator

- Simulator Changes
  - Hardware changes
  - Updates to simulator models including re-tuning of the core physics model for cycle-specific data
  - In accordance with ANSI/ANS 3.5-1985, TVA committed to collecting data during implementation & start-up testing to benchmark simulator

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# Conclusion

- The licensee has:
  - Addressed the effects of the proposed EPU on operator actions
  - Taken or has committed to take appropriate actions to ensure that the EPU does not adversely affect operator performance
- The licensee will continue to meet applicable NRC requirements related to human performance
- With respect to human factors the Staff finds the licensee's proposed EPU acceptable

# Mechanical & Civil Engineering

## Safety Evaluation Section 2.2

Primary Reviewers:

| | |
|---|---|
| Thomas Scarbrough | Component Performance & Testing |
| Cheng-Ih Wu | Engineering Mechanics Branch |

# Evaluation Areas

## Engineering Mechanics

- Pressure-Retaining Components
  - Piping, Components and Supports
    - Nuclear Steam Supply System (NSSS)
    - Balance of Plant Systems (BOP)
  - Reactor Vessel and Supports
  - Control Rod Drive Mechanism
  - Recirculation Pumps and Supports
- Reactor Vessel Internals and Core Supports
- Seismic and Dynamic Qualification of Equipment

# Components and Supports

- Components and supports evaluated
- Analyses used for Power Uprate consistent with NRC-approved guidance
- Limiting seismic loads remain unchanged
- Original LOCA dynamic loads are bounding
- Calculated stresses and Cumulative Fatigue Usage Factors were less than the Code allowable limits

# NSSS & BOP Piping

- Limiting seismic loads remain unchanged
- Most limiting LOCA dynamic loads are bounding
- Calculated stresses and Cumulative Fatigue Usage Factors were less than the Code allowable limits
- Units 2 and 3 have successfully operated at 105% power since 1998

# Seismic and Dynamic Qualification

- Seismic loads unchanged
- No new pipe break locations or pipe whip and jet impingement targets
- No increase in pipe whip[ and jet impingement loads
- No increase in Safety Relief Valve and LOCA dynamic loads

# Unit 1 Steam Dryer

- Unit 1 steam dryer and steam system design similar to Units 2 and 3
- Units 2 and 3 have successful 105% OLTP operational experience since 1998
- Unit 1 steam dryer is modified to be more robust and stronger than Unit 2 and 3 dryers
- TVA will monitor Unit 1 main steam pressure fluctuations and vibrations and conduct walkdowns during power ascension up to 105% OLTP

# Unit 1 Steam Dryers

## Proposed Modifications

- 1-inch hood face plates
- 1-inch cover plates
- Improved design tie bars
- Improved weld designs at hood face plates
- Additional modifications may be necessary

# Steam Dryer Analysis

Status

- TVA submittals did not demonstrate the steam dryer would maintain structural integrity under 120% EPU conditions
- TVA requests 105% power uprate to support restart of Unit 1
- TVA has collected main steam pressure fluctuation data to support 120% EPU
- Staff awaiting submittal of revised analyses

# Power Ascension Procedure

Restart to 105% OLTP

- Main steam pressure fluctuations monitored hourly and at least every 2.5% power step
- Moisture carryover determined every 24 hours
- Steam piping acceleration measured once every 2.5% power step
- Periodic walkdowns of steam, feedwater, and condensate systems
- Performance criteria and required actions based on moisture carryover and main steam line pressure spectra data

# Proposed License Conditions

Upon Reaching 105% OLTP

- Provide plant data collected according to Power Ascension Procedure within 96 hours
- Submit results of steam dryer analysis for Unit 1 within 60 days

# Outcome

Engineering Mechanics and Steam Dryer

- The following technical areas found acceptable for operation at 105% power uprate conditions:
  - Pressure-Retaining Components and Supports
  - RPV Internals and Core Supports
  - Seismic and Dynamic Qualification of Equipment
  - Steam Dryer and Potential Adverse Flow Effects

# Safety Related Pumps & Valves

## Safety Evaluation Section 2.2.4

# Unaffected Systems

## Safety-Related Valves and Pumps

- Inservice Testing Program (IST) scope and frequencies not affected by power uprate
- No changes in IST Program except specific implementing procedures

# Power Uprate Affects

- TVA committed to complete GL 89-10 Motor-Operated Valve (MOV) program testing within 30 days of startup
- Of 51 MOVs under GL 89-10:
  - 34 have new actuators
  - 17 replaced entirely
  - All have SmartStems
- GL 95-07 pressure locking/thermal binding program results:
  - 3 HPCI & Core Spray (CS) valves with double discs
  - 5 HPCI & CS valves with hole drilled in reactor side

# Acceptance Criteria

## Safety-Related Valves and Pumps

- Regulatory Criteria
  - 10 CFR 50.55a
  - Appendix A, draft General Design Criteria
  - Appendix B, Quality Assurance Criteria
- Regulatory Guidance
  - GL 89-10
  - GL 95-07
  - GL 96-05

# Special Items

MOV Inspection November 28-30, 2006

- Well developed with reasonable design assumptions and operating experience
- More work needed to complete MOV testing and feedback results to confirm design assumptions
- Walkdown found MOVs readied for operation in good condition
- Long-term GL 96-05 follows Joint Owners Group
- MOV program inspection activity closed for restart
- TVA will notify NRC when MOV program complete

# Outcome

The following technical area found acceptable for operation at uprated conditions:

- Safety-Related Valves and Pumps

# Environmental Qualification of Mechanical Equipment

Safety Evaluation Section 2.2.7

# Unaffected Systems

## Environmental Qualification of Mechanical Equipment

- Functional capability of non-metallic components in mechanical equipment inside or outside containment not adversely impacted by power uprate
- Effects of increased temperature, pressure, and flow not significant for environmental qualification of mechanical equipment for power uprate

# Acceptance Criteria

Environmental Qualification of Mechanical Equipment

- Regulatory Criteria
  - Appendix A, draft General Design Criteria
  - Appendix B, Quality Assurance Criteria
- Regulatory Guidance
  - 10 CFR 50.49 Environmental Conditions

# Outcome

The following technical area found acceptable for operation at uprated conditions:

- Environmental Qualification of Mechanical Equipment

# Source Term & Radiological Consequences

Safety Evaluation Section 2.9

Primary Reviewer:
Michelle Hart

Accident Dose Branch

# Power Uprate Affects

- Plant operations and maintenance
- Normal operational environmental releases
- Irradiation effects on RPV and internals
- Offsite doses from design-basis accidents
- Control room habitability during accidents
- Fuel isotopic inventory
- Reactor coolant isotopic concentrations

# Assumptions

## Radiological Evaluations

- Only small changes in reactor core design
- Existing calculations in UFSAR are valid
- Radiological data/dose is changed only by the magnitude of the change in radiation source

# Acceptance Criteria

## Source Term and Radiological Consequences Analyses

- 10 CFR 50.67
- 10 CFR Part 20
- 10 CFR 50 Appendix I
- Appendix A, General Design Criteria
  - GDC-19, Control Room
- Accident-specific criteria in SRP 15.0.1 and RG 1.183

# Alternate Source Term

Prior Approval

- TVA submittal for AST on July 31, 2002
- Adopts AST methodology by revising accident source term IAW 10 CFR 50.67
- NRC approval of full-scope implementation of AST on September 27, 2004

# Outcome

- The following technical areas were found acceptable for operation up to 120% OLTP:
  - Source Terms for Radwaste System Analysis
    - 10 CFR 20
    - 10 CFR 50 Appendix I
  - Alternate Source Terms for Radiological Consequence Analyses
    - 10 CFR 50.67
    - SRP 15.0.1
- Source Term and Radiological Consequences Acceptable for 105% and 120% OLTP

# Radiation Protection

Safety Evaluation Section 2.10

<u>Primary Reviewer</u>:
Roger Pedersen

Health Physics Branch

# Major Areas Of Review

- Increased Source Term / Public Dose for Normal Operation
- Occupational / Worker Doses
- Increased Radwaste
- Increased Core Inventory and In-plant Post-Accident Doses

# Power Uprate

## Radiation Protection

- Radiological Impacts Projected at 3458 MWt (120% of OLTP)
- The 105% Evaluation Bounded by 120% Analysis

# Acceptance Criteria

Radiation Protection

- Regulatory Criteria
  - 10 CFR 20 Dose Limits
  - 40 CFR 190
  - 10 CFR 50 App. I, Effluent System Design Criteria
  - NUREG 0737, Item II.B.2, Post Accident Worker Dose

# Outcome

- The NRC staff finds the radiological protection acceptable based on:
  - Evaluation results at 120% bound operation at 105% OLTP
  - Evaluation results satisfy the Acceptance Criteria
    - 10 CFR 20
    - 10 CFR 50, Appendix I
    - NUREG 0737 and GDC-19
  - Any increases will be maintained ALARA
- Radiological Protection Acceptable for 105% and 120% OLTP

# Electrical Engineering and Instrumentation & Controls

## Safety Evaluation Section 2.3

<u>Primary Reviewers</u>:

| | |
|---|---|
| Om Chopra | Electrical Engineering Branch |
| Sang Rhow | Instrumentation &Controls Branch |

# Electrical Systems

Unaffected Components/Systems

- Emergency Diesel Generator
- AC onsite power systems
- DC Batteries (for 105% EPU only)
- Unit Auxiliary Transformer
- Start-up Transformer

# Electrical Systems

Power Uprate Affects

- AC Power
- DC Power
- Isolated Phase Bus Ducts
- Main Transformer Banks
- Environmental Qualification

# Power Uprate Affects

Offsite

- Change in Load Demand
  - Condensate Pumps
  - Condensate Booster Pumps
- Main Generator Uprate
  - Main Tap Isolated Phase Bus Duct
  - Generator Breaker
  - Main Power Transformer
- Operating Flexibility
  - Switchyard
    - Buses
    - Breakers
    - Switches

# Power Uprate Affects

## Onsite Electrical

- Onsite Power Analysis Changes
  - Motor replacements
    - Reactor Recirculation Pump Motors
    - Condensate Pump
    - Condensate Booster Pumps
    - Installation of Recirculation Motor-Generator Set Variable Frequency Drives

# Electrical Programs/ Issues

- Grid Stability
- Station Blackout
- Environmental Qualification

# Intent of Analysis

Electrical Systems

- Determination whether
  - Operation under increased electrical output and increased plant load
  - No load increase expected on safety equipment due to maintained ratings
  - Existing Environmental Qualification envelopes remain valid

# Electrical Systems

## Acceptance Criteria

- 10 CFR 50.49
  - Environmental Qualification
- 10 CFR 50.63
  - Station Blackout
- 10 CFR Part 50, Appendix A, GDC-17
  - Electrical Power Systems

# Outcome

## Electrical Systems

- The following technical areas were found acceptable for operation at uprated conditions
  - Environmental Qualification of Electrical Equipment
  - Offsite Power Systems
  - Onsite Power Systems
  - Station Blackout

# Instrumentation & Controls

# Instrument Setpoint Review

- Setpoint Methodology
- Analysis Review Setpoint Changes
  - High Neutron Flux
  - Vessel Scram and Recirc Pump Trip
  - Main Steam Line Isolation
  - Turbine-Generator Trip Scram
  - Feedwater Flow Setpoint
  - MSIV Closure

# Acceptance Criteria

- 10 CFR 50.36
- 10 CFR 50.55a(a)(1)
- 10 CFR 50.55a(h)
- AEC Draft General Design Criteria
  - Draft GDC 1, Quality Standards and records
  - Draft GDC 4, Environmental and dynamic
  - Draft GDC 13, Instrumentation and Control
  - Draft GDC 20, 21, 23, 24, 25, 26, Reliability and Testability of Protection Systems

# Instrumentation and Control

Staff Review

- Systems continue to meet safety functions
  - Methodology ensures appropriate margin set
  - Setpoints within the established setting tolerance
  - Setpoints selected to ensure that the value selected does not significantly increase the likelihood of a false trip or failure to trip upon demand

# Setpoint Methodology

- Limiting safety system setting for safety limit
  - Automatic protective action corrects the abnormal situation before a safety limit is exceeded
  - TS limits required for instrument channels that initiate protective functions
- Use plant-unique alternative
- Alternative reviewed under separate amendment
- Approach found acceptable

# Instrumentation & Controls

## Modifications and Variable Changes

- No modifications to instruments for power uprate
- Revision to various setpoints due to the change
  - Pressure
  - Neutron Flux
  - Recirculation flow

# Resultant Setpoint Changes

Unit 1 105 % Changes

- Reactor Protection System Instrumentation
  - Average Power Range Monitors
    - Neutron Flux - High (Setdown)
    - Flow Biased Simulated Thermal Power - High
- ATWS-RPT Reactor Steam Dome Pressure
- Reactor Vessel Steam Dome Pressure -High

# Resultant Setpoint Changes

120% Changes

- Reactor Protection System Instrumentation
  - Average Power Range Monitors
    - Neutron Flux - High (Setdown)
    - Flow Biased Simulated Thermal Power - High

# Outcome

Instrumentation and Controls

- The staff found the proposed allowable value changes acceptable

  - Allowable Values Changed
    - Use a method acceptable to the staff
    - Values selected conservative to the calculated values
  - Setpoint changes (allowable values)
    - Maintain sufficient margins between operating conditions and the trip setpoints
    - Do not significantly increase the likelihood of a false trip or failure to trip upon demand

# Materials and Chemical Engineering

## Safety Evaluation Section 2.1

<u>Primary Reviewers</u>:

| | |
|---|---|
| Ganesh Cheruvenki | Vessels & Internals Integrity Branch |
| George Georgiev | Piping and NDE Branch |
| Matt Yoder | SG Tube Integrity &<br>Chemical Engineering Branch |

# NRC Staff Review

## Applicability

- Unit 1 at 105%
- Unit 1 at 120%
- Units 2 and 3 at 120%

# NRC Staff Review

## Affected Areas

- Reactor Vessel Material Surveillance Program
- Pressure -Temperature Limits
- Upper Shelf Energy
- Reactor Internal and Core Support Materials
- Reactor Coolant Pressure Boundary Materials
- Protective Coatings
- Flow Accelerated Corrosion
- Reactor Water Cleanup

# Reactor Vessel and Internals

Sections 2.1.1 - 2.1.3

# Reactor Pressure Vessel and Internals

## Components Reviewed

- Reactor Pressure Vessel
- Reactor Pressure Vessel Internals
  - Top Guide
  - Core Plate
  - Core Shroud
  - Incore Instrumentation

# Reactor Pressure Vessel and Internals

- Structural Integrity Assessments
  - Reactor Pressure Vessel Surveillance Program
  - Reactor Vessel Upper Shelf Energy
  - Reactor Vessel Pressure Temperature Limits
  - Reactor Vessel Internal Components
- Renewal period

# Structural Integrity Programs

## Effects of EPU on Reactor Pressure Vessel

- Integrated Surveillance Program
  - Complies with 10 CFR Appendix H
  - Approved for extended plant life
  - Dosimetry program and fracture toughness evaluation
  - Schedule not affected
- Upper Shelf Energy
  - TVA used Topical Report BWRVIP-74
  - Margin in compliance with 10 CFR 50 Appendix G
  - Applicable for extended plant life

# Structural Integrity Programs

## Effects of EPU on Reactor Pressure Vessel

- P-T Limit Calculations
  - Must include effects of neutron fluence under EPU conditions
  - TVA will resubmit P-T limits
- IASCC
  - Reactor Vessel Internals susceptible to IASCC
  - TVA's chemistry control program
  - BWRVIP inspection guidelines
  - TVA demonstrated adequate AMPs to monitor aging effects on internals

# Reactor Pressure Vessel and Internals

## Acceptance Criteria

- Regulatory Criteria
  - 10 CFR 50.60
  - 10 CFR Part 50, Appendix H
  - 10 CFR Part 50, Appendix G
- Regulatory Guidance
  - RS-001, Revision 0, Review Standard for Extended Power Uprate

# Outcome

## Reactor Pressure Vessel and Internals

- The following technical areas were found acceptable:
  - Reactor Pressure Vessel Surveillance Program
  - Reactor Vessel Upper Shelf Energy
  - Reactor Vessel Pressure-Temperature Limits
  - Reactor Vessel Internal Components

# Reactor Coolant Pressure Boundary Materials

## Section 2.1.4

# Power Uprate Affects

## Reactor Coolant Pressure Boundary

- No Significant Increase
  - Flow
  - Pressure
  - Temperature
  - Mechanical loading
- Slight Increase in Oxygen Generation Rate

# Reactor Coolant Pressure Boundary

## Piping Modifications

- Recirculation System
  - Corrosion Resistant Material
  - Low carbon type 316NG Stainless Steel
  - Category A Recirculation System Welds
- Core Spray (Containment)
- Residual Heat Removal (Containment)
- Reactor Water Cleanup
- Jet Pump Instrumentation Nozzle Safe ends

# Outcome

## Reactor Coolant Pressure Boundary

- TVA's programs designed to mitigate IGSCC in Unit 2 and 3 has been reviewed and found to be acceptable by the NRC staff
- Unit 1 program is the same as Units 2 & 3
- RCPB materials will continue to meet
  - 10 CFR 50.55a
  - 10 CFR 50, Appendix A,
  - 10 CFR 50, Appendix G

# Protective Coatings and Flow Accelerated Corrosion

## Safety Evaluation Sections 2.1.5- 2.1.6

<u>Primary Reviewer</u>:
Matt Yoder

SG Tube Integrity &
Chemical Engineering Branch

# Protective Coatings

## Organic Materials

- NRC Staff's Review
  - Coatings Used in Containment
  - Design Basis Loss of Coolant Accident
    - Suitability
    - Stability
  - Radiation and Chemical Effects

# Protective Coatings

## Power Uprate Affects

- Coatings are subject to increased:
  - Temperature
  - Pressure
  - Radiation

# Protective Coatings

## Testing

- Previous Testing
  - Peak Accident Conditions at 120%
  - Service Level 1 Coatings
  - Zone Of Influence Not Impacted
- One Configuration Not Tested
  - Not Previously Used at Browns Ferry
  - Will Not Be Used
- Unqualified Coatings Assumed to Fail

# Acceptance Criteria

## Protective Coatings

- 10 CFR Part 50, Appendix B
- Regulatory Guide 1.54, 1973
- SRP Section 6.1.2, Protective Coating Systems (Paints) - Organic Materials

# Outcome

## Protective Coatings Acceptable

- Qualified coatings continue to be bounded by the qualification test conditions
  - Valid up to 120% power
  - Applicable for all three units
  - Unqualified coatings assumed to fail under accident conditions
- Qualified coatings meet the acceptance criteria for 105% and 120% for all three units

# Flow Accelerated Corrosion

## Uprate Affects

- Change In Process Variables
  - Flow Velocity
  - Fluid temperature
  - Moisture content
  - Oxygen content
  - pH
- Process Variables Should Remain Within FAC Model Parameters

# Flow Accelerated Corrosion

## Program and Acceptance Criteria

- Program Basis
  - NUREG-1344
  - GL 89- 08
  - Electric Power Research Institute (EPRI) Report NSAC-202L-R2
- Acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC

# Outcome

## Flow Accelerated Corrosion

- Adequately addressed changes in the plant operating conditions
- Updated analyses will predict the loss of material by FAC
- Ensure timely repair or replacement of degraded components

# Reactor Water Cleanup System

## Safety Evaluation Section 2.1.7

Primary Reviewer:
Matt Yoder

SG Tube Integrity &
Chemical Engineering Branch

# Reactor Water Cleanup System

## Uprate Affects

- Operate at increased
  - Temperature
  - Feedwater flow
  - Pressure

# Acceptance Criteria

## Reactor Water Cleanup

- SRP 5.4.8
- Draft Design Criteria Continues to Be Met
  - RCPB designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture
  - Means to control the release of radioactive effluents
  - Systems designed to ensure appropriate radioactivity confinement

# Outcome

## Reactor Water Cleanup

- Will continue to performing its function removing
  - Solids
  - Dissolved impurities