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UNITED STATES NUCLEAR REGULATORY COMMISSION'S
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SEPTEMBER 26, 2001

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

THERMAL-HYDRAULIC PHENOMENA SUBCOMMITTEE MEETING

DUANE ARNOLD ENERGY CENTER POWER UPRATE REQUEST

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WEDNESDAY

SEPTEMBER 26, 2001

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ROCKVILLE, MARYLAND

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The ACRS Thermal Phenomena Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 1:00 p.m., Dr. Graham Wallis, Chairman, presiding.

COMMITTEE MEMBERS PRESENT:

DR. GRAHAM WALLIS, Chairman
DR. F. PETER FORD, Member
DR. THOMAS S. KRESS, Member
DR. DANA POWERS, Cognizant ACRS Member
DR. STEPHEN ROSEN, Member
DR. WILLIAM SHACK, Member
DR. VIRGIL SCHROCK, ACRS Consultant

ACRS STAFF PRESENT:

PAUL A. BOEHNERT, ACRS Staff Engineer

I-N-D-E-X

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

(1:00 p.m.)

CHAIRMAN WALLIS: The meeting will come to order. This is A meeting of the ACRS Subcommittee on Thermal-Hydraulic Phenomena. I am Graham Wallis, Chairman of the Subcommittee.

Dana Powers will be the ACRS Cognizant Member for this meeting. Other ACRS Members in attendance are Peter Ford, Thomas Kress, Stephen Rosen, and William Shack. The ACRS Consultant in attendance is Virgil Schrock.

The purpose of this meeting is for the subcommittee to review the license amendment request of the Nuclear Management Company fora core power uprate for the Duane Arnold Energy Center.

The subcommittee will gather information, and analyze relevant issues and facts, and formulate the proposed positions and actions as appropriate for deliberation by the full committee. Mr. Paul Boehnert is the Cognizant ACRS Staff Engineer for this meeting.

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register on September 19th, 2001.

Portions of this meeting may be closed to the public as necessary to discuss information considered proprietary to General Electric Nuclear Energy. Please let us know if and when that is the case.

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

We have received no written comments or requests for time to make oral statements from members of the public. I have a brief opening comment.

The ACRS, before this meeting, received stacks of paper which amounted to over a foot in height. We obviously don't have time to read and digest every word.

So I think that it is very important that the speakers focus on what issues the ACRS needs to consider and what information we are going to need to reach decisions on those issues. And I believe that Dr. Ford has a statement to make.

DR. FORD: Yes. I am a GE retiree, and therefore I have a conflict of interest.

CHAIRMAN WALLIS: Now I would like to ask my colleague, Dana Powers, to take over my job for a while and to run the meeting.

DR. POWERS: Thank you Professor Wallis. We are going to be looking at one of the first of the major power updates that we seem to have coming along the pike here. This is a truism that the boiling water reactors in this country typically operate at powers that are less than what they were originally conceived of operating at.

And in part that was because of a historic -- a long time ago many ACRS' before this current version of it had particular concerns about DWR stability at the higher power.

What we are going to try to cover is a huge amount of material. Professor Wallis' is over a foot, and he must have only gotten half of it if he only had a foot.

CHAIRMAN WALLIS: Over a foot. I was being conservative.

DR. POWERS: And the plan of attack is that we are going to listen to the applicant this afternoon, and then tomorrow we are going to listen to the staff tell us why we should have believed everything that was told to us from the applicant.

And so I am going to turn now to Ron

McGee, the power uprate project manager, to start the presentation, and you will introduce the additional speakers as the need arises.

And remain cognizant that should we have to deal with proprietary material, that creates a huge disruption. So you have to let us know beforehand.

MR. MCGEE: Good morning then. My name is Ron McGee, of the Nuclear Management Company at the Duane Arnold Energy Center. I would like to thank the committee for taking the time to review our submittal and for meeting with us today.

We recognize the importance of power updates as part of the solution to meeting the country's future energy needs, but foremost we must ensure that public safety is not jeopardized.

We believe that through our engineering evaluations and the staff's review process the DAEC application for a power uprate has shown an adequate amount of operational design and safety margin for the various facets of the project.

Today, we have been asked to present the following topics. I will be presenting the plant changes and modifications, and then we will talk quickly about the regulatory compliance, the analysis performed as part of the project, and then we have been asked to discuss margins, which I will get to here in a minute.

Then we go through the operator training that we have applied. Then we will have discussions on thermal hydraulic stability, the ATWS response, and ATWS instability fuel response, material degradation issues, the containment analysis, the effects of power uprate on the steam separator and dryer, ECCS analysis as part of the project.

And then the last presentation is the PRA analysis, and then we will have concluding remarks and a wrap up of any open issues that come up.

CHAIRMAN WALLIS: Did you rehearse this so that it can be over in two hours?

MR. MCGEE: Two hours, no. We have --

CHAIRMAN WALLIS: You are supposed to allow two hours for our questions.

MR. MCGEE: We have accounted for four hours, including questions. We believe that the presentation material, including questions, should be concluded within four hours.

DR. POWERS: It is going to be so clear that that we will have no questions whatsoever.

MR. MCGEE: The first presentation will be where we go over the power uprate modifications that we performed as part of this project. The safety related modifications -- and I will point out that these are the only safety related modifications that were necessary to accommodate the power uprate.

These were installed in our recent outage, and we installed new APRM cards, installed higher range main steam line flow implementation, and we through a previous amendment, we have increased our required boron concentration for a standby liquid system.

The balanced plant modifications. We installed higher capacity transformer; coolers -- improved cooling capacity on our hydrogen coolers for our main generator.

A major modification was that we replaced the high pressure turbine, and the feed water level control for the feed water heater system had to be modified to accommodate the higher capacity. As part of the ELTR, we have installed flow induced vibration monitoring.

CHAIRMAN WALLIS: What does Phase One mean?

MR. MCGEE: As part of our uprate, we intend to go up from 1658 megawatt thermals, our current license power level, and we intend to operate at 1790 megawatt thermal. And then following a future outage, we plan to ascend to the rest of the license.

CHAIRMAN WALLIS: So you are applying for the whole thing?

MR. MCGEE: That's correct. We are applying for the license to 1912 megawatts thermal. But a balance of plant modifications will only accommodate operation up to 1790 for this interim period.

MR. BOEHNERT: What are the percentages, Ron? Do you know roughly?

MR. MCGEE: Approximately halfway each time; 8-1/2 percent right now, and then another 8-1/2 percent on top of that. Feed and condensate pump breaker, protective relaying set point, condensate the demineralizer capacity as part of the feed water flow stream.

And the main condenser tubes because of the increased steam flow, and added structural support.

CHAIRMAN WALLIS: I actually have to agree on the language. I noticed in this staff review that they are talking about 120 percent increase?

MR. MCGEE: The 120 percent that is from original license --

CHAIRMAN WALLIS: No, no, no.

MR. MCGEE: Oh, increase.

CHAIRMAN WALLIS: A twenty percent increase.

MR. MCGEE: Yes.

CHAIRMAN WALLIS: The staff was talking about 107 percent, and it is really mind-boggling.

MR. MCGEE: That would be Unit 2.

DR. KRESS: You went by one of our slides a little too fast. You talked about whether one of the mods was a MELLLA APRM card, and I know what the MELLLA is and all of that, but his this card an automatic controller to make sure that you go along the MELLA line? What is the card?

MR. MCGEE: The card actually monitors your flow by SCRAM set points, and supplies the trip function into your RPS system, reactor protection system.

DR. KRESS: Okay. That's what I thought, but I wanted to make sure.

MR. MCGEE: That's correct. The next slide. Continuing with our balanced plant modification; isophase bus temperature monitoring for the electrical load increase; and monitor the temperature.

And the main steam line relief value snubber was one support that we needed to increase. One of our feed water heaters was going to have a significant increase in its load carrying capacity, whereby bypassing the flow to the main condenser.

And control room indications and alarms have been modified to accommodate the previous modifications that you have seen here.

Phase Two, when we go from 1790 up to 1912, preliminarily, we have identified feed water system capacity, and we will need to increase the system capacity from about 8.1 million pound mass to something just greater than 8.75 million pound mass per hour.

Feed water heaters. Their load bearing capacity will need to increase, and so we are anticipating the need to increase various feed water heaters. And then our isophase bus to carry the increased electrical loading.

MR. ROSEN: You said the increased feed water, and the slide says replacement. Are you going to replace the heaters?

MR. MCGEE: We do plan to replace feed water heaters, certain ones.

MR. ROSEN: But not all of them

MR. MCGEE: But not all of them, that's correct. Some will be at the upper -- increased at the EPU power level, and will be within their design to carry the amount of increased loading, but the three, four, and five heaters -- we have six heaters, and the 3, 4, and 5s right now looks like they will be marginal. So we will be looking at a wholesale change outs of those.

MR. ROSEN: Those are the low pressure heaters?

MR. MCGEE: Those are high pressure heaters.

MR. ROSEN: And the low pressures are all right, but the high pressure heaters need to be changed?

MR. MCGEE: The ones and twos are the lowest pressure, yes, that's correct. Those are okay.

MR. ROSEN: So you are saying that you are looking at it. It is curious language. You are looking at replacing them.

MR. MCGEE: Yes. We are planning to replace all of the heaters. We are looking at designs and depending on how and which ones you replace, that will determine the need to replace others. Next slide.

The next topic was regulatory compliance. Our application was a deterministic application, and it is not a risk-informed application. It was performed in accordance with previously approved ELTRs 1 and 2.

The process for the application and the studies includes a feasibility study, which was conducted in late 1999. Engineering evaluations throughout the year 2000, et cetera. The licensing reports, which you have seen most of, I believe, if you have gotten a foot of paper.

The hardware modifications that we have just reviewed, and then post-approval, and we have testing to perform, and we have performed preliminary testing up to our current license power uprate.

CHAIRMAN WALLIS: You said this was not a risk-control, and yet one of the major consequences here is the operator reaction time during ATWS. One of the major concerns in that seems to be resolved on a risk basis rather than some sort of compliance.

MR. MCGEE: We do have a presentation that will include discussion of that topic if you would like to wait for that.

CHAIRMAN WALLIS: Okay. You will address that at that time?

MR. MCGEE: We will.

MR. MCGEE: The analysis performed. The general topics were the reactor operating conditions, accidents and transients, the radiological consequences of a power uprate, component system capacity, including NSS and BOP; instrumentation and controls; the environmental impact of the power uprate.

And then a review of the station programs. For instance, PSA, environment qualifications, station blackout, et cetera.

The generic topic of margins. We were asked to discuss that. And what we have done is included a discussion in the rest of the presentations today to address the impact on margins on the specific topics.

And then if the committee would like to follow on with questions during those times, I would propose that is how we address those. And next will be Steve Kottenstette.

MR. KOTTENSTETTE: Hi. I am going to be talking about operator training. My name is Steve Kottenstette, and I am an operations shift manager on loan to the power uprate project.

We started out using classroom training.

We took the material from the power uprate project and we discussed with the operators how the procedures are going to change, and how the tech specs will change, and the testing that we will do as far as the power uprate probe.

And then we moved into the simulator, where we took what we believed would be the best guess on how the plant will operate, and use a simulator, and through the various operational transients that we would see a trip over recirc pump, a trip of the feed pump, turbine trips, reactor SCRAMS.

And then we also went into some of the accident scenarios, where we went through an ATWS and showed the operators the benefits of injecting standby liquid control early on in the scenario, and then showed what would happen if we didn't inject standby liquid control, or had a failure to inject.

We did a turbine trip and SCRAM scenario, and then we also did an MSIV closure, and did show the operators how much it did change. And for the most part, there was very little change as far as our actions and how the plant responded once a plant was shut down.

DR. SCHROCK: Could you embellish a little on what you mean by your best guess as to how the plant is going to perform?

MR. KOTTENSTETTE: We took the model or the design information of the plant modifications, and the change out of the conset pumps and the feed pumps, and the reactor model, and we basically gave it our best guess on how it should respond.

And then we also benchmarked it against the accident analysis that we got from GE, as far as this is how the plant should respond to a turbine trip, or an MSIV closure.

And we looked to see how the simulator responded, and it pretty much matched up to what we saw or the information that we got from the analysis.

CHAIRMAN WALLIS: Do you have any sort of feedback for how well the operators responded to this? I mean, you trained them and you would tell them these various things, and then it is supposed to change their performance in some way or their reaction at the time, or whatever.

Do you have a measure of how well they did after training?

MR. KOTTENSTETTE: During the training, it was obviously observed during the training that the operators responded per our procedures, and as far as containing the scenario and responding to it, there was no marked decrease in operator performance.

CHAIRMAN WALLIS: So you don't try to measure the probability of them doing the right thing? This is somehow only an analytical assessment?

MR. KOTTENSTETTE: As far as how the operators responded, or --

CHAIRMAN WALLIS: There are numbers that are given to us in the paperwork about the probability of human error during an ATWS, and the numbers have increased.

And I just wondered if there was any measure from this training to show whether or not the operators were under more pressure, and made more mistakes or whatever with the power uprate than you would get from the simulator experience.

MR. KOTTENSTETTE: We didn't see any increased errors.

CHAIRMAN WALLIS: But did you look for any?

MR. MCGEE: This is Ron McGee once again. The operators during their training scenarios have critical tasks that they have to perform in their dynamic scenarios, and the operators on the power uprate tasks all successfully performed the critical tasks.

There were no operator failures or remediations necessary during the power uprate phase of the test of the classroom or simulator training.

MR. ROSEN: I think we will hear later that the time for action, taking the required actions, is shortened by this uprate, but that what you are saying is that the operators were able to take the necessary actions in spite of the shortened times allowed.

MR. KOTTENSTETTE: Yes, because there is a very simple process of actually initiating standby liquid control.

MR. ROSEN: It is all right there in front of them, the keys and the mode switch?

MR. KOTTENSTETTE: The keys and the mode switch, and take it out of the mode switch and put it in the switch for the controls for the pumps.

MR. MCGEE: And we specifically monitored for that, for the operator taking those appropriate actions on standby liquid. And all of the currently licensed crews were able to perform that action satisfactorily.

MR. ROSEN: And I think we will hear more about that in the PSA discussion I assume?

MR. KOTTENSTETTE: Yes, you will.

MR. MCGEE: Yes, that's correct.

CHAIRMAN WALLIS: I'm sorry, but you have your schedule. When are we going to get into other questions that are not on your plans, such as the stresses in the components and a question that we might have about something that is not in your outline? Do we leave that to the end?

MR. MCGEE: That is an option.

DR. SHACK: It seems to me that we ought to bring them up when they are appropriate, Graham.

CHAIRMAN WALLIS: Well, if they never raise the issue, we are going to have to bring in up sometime.

MR. KOTTENSTETTE: There is a section on material issues, and that may be the appropriate time to do that.

CHAIRMAN WALLIS: Well, I had a very basic question, which is that this is going to be a constant pressure power uprate?

MR. KOTTENSTETTE: That is correct.

CHAIRMAN WALLIS: And I just wondered why the stresses went up in things like the main closure flange, the vessel and the head if there were no changes in pressure? And they go up by 10 percent or more than 10 percent, and why is that?

MR. MCGEE: Gary is looking. We have several people looking.

CHAIRMAN WALLIS: Well, maybe we can after the break come back to this question. That is a very, very basic question that I had to raise at some time. So, think about it.

DR. POWERS: It had to be a flow. It can't be anything else.

MR. BROWNING: Carrying on, next we are going to talk about the thermal-hydraulic stability, and my name is Tony Browning, and I am from Duane Arnold.

We will have General Electric and Jason Post here to my right giving part of the presentation; and Mr. Kottenstette said he will get back up and talk about the impact on the operations of the power plant.

So we will kind of go through a little bit of quick background and the calculational methodology. Then I will get back up and discuss the analytical results. Then we will get into some of the issues that the committee has raised about the Solomon monitoring system.

And then the operational aspects as I said by Mr. Kottenstette, and then we will have a quick conclusion. Our purpose here is to demonstrate to the committee that we have adequate operational and safety margin at the EPU conditions. So with that, I will turn it over to Jason.

MR. POST: Good afternoon. My name is Jason Post, and I am with GE. Stability solutions. The general design criteria is that GE C12 does neither prevent or reliably and readily detect and suppress reactor instabilities.

Duane Arnold has stability option 1-D, which does both. So they have features that both prevent and detect, and suppress. Their prevention feature is in an exclusion zone in the power flow map.

It is down in the low flow and high power corner of the power flow map. It is defined with the frequency -- the main model, and it has a very conservative decay ration margin, .8.

So, of course, we wouldn't expect an oscillation to grow and continue to grow until the decay ratio was 1.0 or higher. But they have a .8 decay ratio, and so there is margin built in right there.

And they have a buffer zone outside of the exclusion region. Of course, as an exclusion region, you cannot operate in that region at all. If you enter that region, you have to immediately exit.

The buffer zone is five percent of power and flow outside of that region, and so that would be even a more conservative, and even a more lower decay ratio value for that.

And you can go into that if you are sure that you have a low decay ratio, and that is from the SOLOMON code. It is an on-line monitor based on the ODYSY code, and that is how you ensure that you maintain a low decay ratio in that region.

CHAIRMAN WALLIS: This exclusion zone is based on theory isn't it at this stage? You have not built these cores with flux and higher power, and so we don't yet know when oscillation is actually going to occur with these cores do we?

MR. POST: Well, we have had instabilities in cores, and so we have a pretty good idea of where they occur, and the most recent one was at the Columbia Power Plant back in about 1995, I believe.

And so we have seen them, and we have a pretty good idea. We benchmarked those cases with our models, and so we have a pretty good idea.

DR. KRESS: But those aren't at the power densities that you are talking about, at the power levels and the flows. They are at the original values, right? The question is does that instability region expand or change?

MR. POST: Right, and we do expand it based upon the same models.

DR. KRESS: You use the models to expand it?

MR. POST: Right. The key factor is really the highest license rod line. So the change to EPU is not as significant as the change from ELLLA to MELLLA.

In fact, we already have plants that are operating with MELLLA. So, it is not a significant extension of the methodology. It is consistent with what we have already operated plants at.

CHAIRMAN WALLIS: And presumably when you start up this plant, you use some sort of a warning that the are exclusions that we have calculated, and if you get close to it, you had better be observant.

MR. POST: Exactly, and Steve -- and later in here we have a start-up map to show how they go outside the region and discuss how the SOLOMON code is used as they come up outside the region. So that is a specific part of this in a couple of more slides.

CHAIRMAN WALLIS: So you might have to modify SOLOMON based on what you actually observe, or is that independent?

MR. POST: The modification is simply in terms of the inputs to the code to make sure it knows what the operating conditions are. The code itself doesn't have to be modified.

So that is the prevention features. The detect and suppress features. It is important that the oscillation for Duane Arnold is proven to be only a core-wide mode, and so the entire core is going up and down at the same time; as opposed to a harmonic, where you get a side to side.

And if you had a side by side, then the average power tends to be flattened out, and your APRM, which is your average power range monitor, gives a relatively flat response.

But if it is a core-wide mode, then the oscillation is easily picked up by the APRMs. So that existing hardware is where we demonstrate that that existing hardware does provide adequate protection of the safety limit.

MR. ROSEN: And you are sure that the Duane Arnold core will respond in a core-wide mode because of its tight neuronic coupling?

MR. POST: That's correct, and that is part of the demonstration; that the core-wide remains the predominant oscillation mode.

MR. ROSEN: Will you say more about why it is tightly neutronically coupled?

MR. POST: We will say a little bit more, and we will make sure and see if you have any more questions about that.

MR. ROSEN: Okay.

MR. POST: Next slide. So the prevention methodology is the ODYSY code. When the stability solutions were initially developed, we used the FABLE code, which was another frequency to the main model, and ODYSY is just a much better code.

It was initially applied for another stability solution, the enhanced Option 1-A solution, which is a prevention solution. And so we extended it to Option 1-D, and the SER for that was just issued in April.

So the Duane Arnold extended power uprate is the first application, and Duane Arnold is operating in Cycle 18 right now for their current license power, with stability regions based on the ODYSY code.

It is important to note that when we licensed ODYSY that we replicated the results with FABLE, and the way that we did that was by adding an additional .15 margin in the decay ratio criteria. So while we say there is a .8 criteria, really .65 is what is being calculated by ODYSY as our limit for the exclusion region.

And then we add .15 just as an adder to get the .8 that we are using on the stability criterion now. And as I said before, ODYSY is also the basis for SOLOMON. Next slide.

So this is the stability criteria map, and in the lower right-hand side is where you have a high channel decay ratio, and a low core decay ratio.

That is the type of condition where you can get a channel flow instability, and the fuel is specifically designed to avoid or to ensure that that cannot happen.

And then in the upper left-hand side, that is where you have a high core decay ratio and a low channel decay ratio, and that is where you get a core-wide mode instability.

And then where the cupus is taken out in the upper right-hand corner, that's where you have relatively high core and channel decay ratio, and that's when the higher harmonics can cause a regional mode instability.

So we use the 0.56 as the stability criteria and as the dividing line between when a core-wide mode and a regional mode instability can occur. And this stability criteria has been around for a long time.

It goes back to the time when the LaSalle instability happened or before, and it has been supported by various tests and events to show that that is the difference between when core-wide and channel instabilities occur.

So we don't do a separation type calculation, for example. We don't go into all those other arguments. We just use that as long as the channel decay ratio is below .56 when the core decay ration exceeds .8, that that is a basis for demonstrating that core-wide is the predominant mode. And I will turn it back over to Tony.

MR. BROWNING: And this gets into some of the things that we have talked about, and we will walk through them fairly quickly. The development of the exclusion zone power to flow map was a critical piece of this.

Jason just discussed the confirmation that we were still having core-wide oscillations only, and our maximum channel decay ratio was a value of .36, which you can see is well below the .56 acceptance criteria that you just saw on the stability maps.

So we are still predominantly core-wide. We also integrated the new flow bias trips from going from ELLLA to MELLLA, and you will see that has the biggest impact on the results. Not so much the power uprate itself, but it is more driven by the change to MELLLA.

And then we go through the confirmation that the flow bias SCRAM at the MELLLA level will protect the safety limit, minimum power critical power ratio in the fuel, and that is a critical part of the analysis.

And then we will go through a little comparison of pre-EPU and EPU results so that you can see that change. Okay. Steve. Here is the power to flow map that we have been talking about, and as Jason mentioned, the exclusion zone is the area where we are not allowed to operate in steady state, and it is in the high power low flow portion of the power flow map.

And one of the other things that I would like to point out --

CHAIRMAN WALLIS: That zone has boundaries that go all the way around it. It is above the red line?

MR. BROWNING: You are not allowed to operate in this region. You have to state on this side of the line. The exclusion zone is inside --

CHAIRMAN WALLIS: Up there?

MR. BROWNING: In here. And the other thing that we would like to point out is we keeping talking about the change from ELLLA to MELLLA. The black line is the ELLLA current load line.

And then you see the impact of MELLLA. And while it is fairly dramatic at the top end at rated power, down here in the stability region, you will notice that it is not that dramatic, and that really explains later why you are not seeing a huge change when we go from ELLLA to MELLLA, or going into power uprate.

And that's because we are talking about this area down here, and you can see that the impact is not that big. Next slide. And what we do is we go through the APR flow by flux trip, and like we said, going from ELLLA to MELLLA, we raise all the trip points up consistent with that.

And then the impact, of course, is that by doing that we have moved slightly further away for the SCRAM. So when we get into the oscillation calculations, and look at the hot bundle oscillation magnitude at the H BOP, it takes just a little bit longer for the automatic SCRAM to terminate the oscillation, because we have moved that much further up away from that corner of the power flow map with the automatic trip.

And that is the predominant thing that we see. Looking at the impact, and I know that this slide is a little busy, but we are trying to show that all the changes we made aren't that dramatic.

When you look at where the current power level rated exclusions and buffer zones are, and how they just shift slightly with the uprate. You will notice that they are almost anchored on the natural circulation line, because almost nothing changes there, and slightly greater sub-cooling has a slight effect down here.

But the biggest impact is shifting up from the ELLLA to MELLLA point. You just take it and you drag it over.

CHAIRMAN WALLIS: Well, I think you ought to explain some things to me. I mean, if I am starting up a plant, and I have no flow and no power. I am at zero. How do I get here?

MR. BROWNING: We are going to show you that.

CHAIRMAN WALLIS: Because it looks to me as if you can't get there without -- you know, I don't see any reason that you are allowed to operate in it.

MR. BROWNING: Steve will show you that shortly. We have a power flow map that actually shows that.

CHAIRMAN WALLIS: But that lower code, the one you call natural circulation.

MR. BROWNING: Yes.

CHAIRMAN WALLIS: You have to be to the right of that, or the left of it, or what?

MR. BROWNING: We are going to be to the right of it. We are going to come up this way.

CHAIRMAN WALLIS: Then you have got to be below that other black line haven't you?

MR. BROWNING: Yes, we have to clear the feed water protection line here on the recirc pumps.

CHAIRMAN WALLIS: And you have to be below that?

MR. BROWNING: Yes. We have to be above it.

MR. MCGEE: That is at minimum.

MR. BROWNING: We have to clear this line before we can increase recirculation flow. So we pull rods and heat up the plant on minimum pump speed, and clear this interlock, and then we can increase in flow and go in this direction.

And then continue to pull control rods out and go up on this side of the exclusion zone. And we will show you a power flow map where we have an example of that.

DR. KRESS: And then when you get up on the MELLLA line, that is strictly a flow power. You don't have to pull the rods out there anymore?

MR. BROWNING: Right. You get as high as you can on the load line, and then you just cruise on up with the recirculation flow. That's correct.

Now we are going to talk about SOLOMON a little bit because we had some inquiry from the committee about the SOLOMON software, and the stability monitor. As Jason has already said, it is the ODYSY model.

It has been integrated into the plant core physics monitoring software. It is an integral part of it. It does not run separately. It runs with it, and it takes its input from it.

Its purpose? It is a backup for what are called power shaped controls, because back in the original days of this stability, one of the things that was of a concern was that the power shapes that were modeled in the bundles, how did we know that we were going to stay in that operating environment, and be bounded by what was assumed in those analysis?

So we have what are called backup power shaped controls. So other options use things like boiling boundary. For the Option 1-D plants like us, we use the SOLOMON software and the buffer zone as our backup power shaped control to maintain that margin.

And what it does is that it merely allows us to sustain operation in the buffer zone and the power flow operating maps. So that little band that we were talking about adding on of the 5 percent, when SOLOMON is available, the operators are allowed to transgress through that area and go through it.

If the SOLOMON software is not available, it becomes an extended exclusion zone, and they are not allowed to operate there.

MR. ROSEN: Is the ODYSY code actually running in the background, or is it SOLOMON looking up results, and pre-store the results of ODYSY?

MR. BROWNING: It is actually running, but it is not real time. It takes a while to do the calculation. So it takes its input from the core physics program, and then runs its time domain calculation, and comes out with the decay rations.

MR. MCGEE: Frequency domain.

MR. BROWNING: I'm sorry, frequency domain calculations, and comes up with a decay ratio, and this displayed to the operators.

MR. ROSEN: So it is possible for the operators, if they are moving very quickly, to outrun ODYSY and SOLOMON, or how do you prevent that?

MR. KOTTENSTETTE: You mean as far as -- you know, if I change the power real fast, then --

MR. ROSEN: If ODYSY sees you changing power, it goes back and tries to calculate the new outputs, but you have changed again before it ever catches up with you.

MR. MCGEE: Are you talking about a predictive capability?

MR. ROSEN: yes.

MR. BROWNING: That is one of the things here. It is a predictive capability. You can look ahead and the reactor operators do that on a rod sequence exchange, or a start up. They will have planned the sequence that they are going through in the start up process.

And they will have done predictive SOLOMON cases ahead of time, and tried to map out exactly where they are in stability space as part of their normal package that they bring up to the control room for the operators to use during those operational scenarios.

And it is because of this, because it is not real time, and exactly what we were talking about. It can't keep up. It just can't do the calculation fast enough.

And the other thing that we need to understand is that it is not monitoring the in-core neutron detectors in a time domain. It is not actually looking for an oscillation. It is doing a predictive calculation in the frequency domain, using the inputs from the physics, just like you would run it to do it for a reload.

CHAIRMAN WALLIS: But you need this rather than just having a code which is permanent because of changes in the burn up or something? Why do you need to have any calculation at all if you have already calculated it once?

MR. POST: Can I answer that?

MR. BROWNING: Sure.

MR. POST: Jason Post again. When we first proposed Option 1-D to the staff, they wanted an extra measure of protection to make sure that you were maintaining your stability condition with a loaded K ratio and with the core-wide mode as the predominant mode. So it was added as an extra feature at the staff's request.

CHAIRMAN WALLIS: And so it follows the burn up changes and changes in power distribution or something?

MR. POST: All that is built into it from the input.

DR. POWERS: From the physics.

MR. ROSEN: So the operators know how to start up and avoid the instability region, and they also have SOLOMON cases which they have run along the line of their intended path to full power.

MR. POST: Right.

MR. ROSEN: And have basically checked out to make sure that they are stable using SOLOMON, which is really running ODYSY, or taking ODYSY results.

MR. POST: That is correct. And that is a great lead in to Steve here, who is next.

CHAIRMAN WALLIS: All right.

MR. KOTTENSTETTE: I am Steve Kottenstette again.

DR. SCHROCK: Could I ask one more question. Where does the thing typically begin steaming in this start up period?

MR. KOTTENSTETTE: Usually at one percent power. Usually we get to the point of adding heat is usually right around 4 to 5 percent power.

DR. SCHROCK: So, 4 to 5 percent. Okay.

MR. KOTTENSTETTE: Okay. As far as the use of SOLOMON, again it is always running, and once a day we get a printout when we are up and running. But since it is always looking at where we are at on the power to flow map, it is automatic as far as when it sees that the plant has gotten into either the exclusion or the buffer zone.

It automatically calculates a case for us and prints it out for us. So like if we have an operational transient where we lost a recirc pump, which is the most probable cause for us to go into the exclusion zone, it will sit there after a time delay and do the calculation, and print out for us where we are at as far as the stability plot.

As far as how we would monitor for thermal stability, we use our APRMs as our primary means to either detect it and to suppress it either when we see it initially, or if it sees it before we can actually take action.

As far as a plant start up, you can see here in the pink line there that that is our typical plant start up, as we come up in power and maneuver around the exclusion and buffer zones.

So once we get up in power and get the generator on line, we are now 3-D, and can actually operate and provide that input to SOLOMON. And you will see that we raise power and lift the control rods enough to get above the interlock for the recirc pumps, where we can increase flow now.

And then once we get up to a point where we can now pull rods again to get it close to our rated low line, and then after that it is just to go up in power with recirc flow.

And then as we get up close to our target rod pattern, there will be minor rod adjustments. And that is where you see all that squiggle up here at the top, as we are making adjustments to account for zanon and other poisons that are burning then.

CHAIRMAN WALLIS: And you said that SOLOMON is run once a day. Is the output from SOLOMON simply to move around these orange lines isn't it, and they change a little bit from day to day; isn't that what it really does?

MR. ROSEN: You said that you run SOLOMON once a day when you are at a steady state?

MR. KOTTENSTETTE: Right. Or at the other end of the power flow.

MR. ROSEN: But when you are going up, how often do you run the SOLOMON when you are making this maneuver?

MR. KOTTENSTETTE: We normally don't run software or ask for a SOLOMON case during a start up.

MR. ROSEN: Because you have several of them already done ahead of time, and you have looked at that as part of your operating plan?

MR. KOTTENSTETTE: Right.

MR. ROSEN: So you know where you are going to be as long as you go up?

MR. KOTTENSTETTE: We know that we are not going to be close to the buffer or the exclusion area.

MR. ROSEN: You got a little close this time didn't you?

MR. BROWNING: Well, this illustrates a good point. This was an actual start up of the plant. This is actual plant data from this past January. So this is at the current power levels and you can see that we stopped it at the current power level.

So we were just trying to highlight here that it is feasible to get around the exclusion and buffer zones, and yes, we got close here, but obviously when the operators get to the uprated condition, they will just move a little further over and just shift it a little bit to the right.

MR. ROSEN: What was the cause in this particular case of the flow dropping off from 26 million pounds per hour to 25?

MR. KOTTENSTETTE: As you go up in power, you get increased resistance to the core, and so flow is going to actually die down or reduce.

MR. BROWNING: Right. We increase the steaming as you are pulling rods and going up.

MR. ROSEN: So with a constant recirc pump speed, you are getting lower -- well, we can see the flow dropping off about a million pounds per hour?

MR. KOTTENSTETTE: Correct.

MR. BROWNING: That's correct. And so the main point and the emphasis was that this region down here, where it appears that we could be constrained, we were just trying to show that the operators do actually have operating margin room in this area to get around this low end.

Because maneuvering out here is not the issue. It is clearing the interlock and then skirting around. And like we said, in conclusion, we tried to demonstrate that the methodology that we use builds in margin, and that the calculational methodology of the ODYSY code, we have accounted for that.

And that the acceptance criteria that

Jason talked about adding the extra .15 on to the decay ratios so that it maps back to the old FABLE code, and so that's how we build in the margin.

And then in our case, plant specifically, we have seen no impact on the safety margins. We have got lots of margin to the decay issue.

CHAIRMAN WALLIS: And how would you define a safety margin?

MR. BROWNING: Well, the safety limit minimum critical power ratio, and that the fact that the APR and flow by scramble protect that,and protect the fuel, and we have demonstrated that in the analysis.

CHAIRMAN WALLIS: So safety margin is a measure obtained by comparing some number with some other number?

MR. BROWNING: Yes.

CHAIRMAN WALLIS: And one is lower by some amount and the safety is the difference between the numbers or something?

MR. BROWNING: Well, what we do is we look at several scenarios, and do the calculation to show the change in the critical power ratio is for those particular transients.

And then we compare that to the safety

limit and show that we have the margin that is required to demonstrate the safety margin is met.

CHAIRMAN WALLIS: Is there something in the law which says what the safety margin has to be?

MR. BROWNING: It is built into the safety limit MCPR, and the value that we use has got margin built into it.

CHAIRMAN WALLIS: So it is clear what is meant?

MR. BROWNING: Right.

DR. SCHROCK: What is the duration of this start up process typically?

MR. KOTTENSTETTE: The typical start up process, from initial start up to 100 percent power, it normally takes about two days to get all the way there.

DR. SCHROCK: So it is very slow?

MR. KOTTENSTETTE: Yes, it is.

MR. ROSEN: Is it very slow during the time that you are going through the door, through that window? How long does it take to get from -- if you will put the slide back up with the maneuvering.

Let's say to go from 13 million pounds per hour, which is the natural circulation, to 20 million pounds per hour? How long does it take you to do that?

MR. KOTTENSTETTE: That should take probably about 15 minutes, because when we increase power with recirc, we pretty much go -- our normal rate is like 2 to 3 megawatts of electric. So, with five percent power, that is going to take about 15 to 20 minutes of adjusting recirc flow.

MR. ROSEN: So in terms of the critical operational period, you are going to go through all those critical maneuvers and be watching the critical parameters.

And it's not like if you have to watch that for two days. You are in the critical region for about 15 or 20 minutes, and from then on you have got a lot more margin.

MR. KOTTENSTETTE: That's right.

CHAIRMAN WALLIS: So one shift does it. It's not as if you are in a critical reason for a shift change or anything like that.

MR. KOTTENSTETTE: No.

MR. ROSEN: In fact, that is a good question, Graham. When you start up do you change shifts at any point during this period?

MR. KOTTENSTETTE: It depends on where we start up on the shift.

CHAIRMAN WALLIS: Well, if it is two days, you better.

MR. KOTTENSTETTE: Well, yes. But we pretty much hold points throughout the start up and get to the point where you get up to the rated pressure, and from there to get to the point where we can roll the generator. And then from there --

MR. BROWNING: And there are prerequisite tests that are required --

CHAIRMAN WALLIS: Are you on 8 hour shifts or 12 hour shifts?

MR. KOTTENSTETTE: We are on 12 hour shifts.

MR. ROSEN: And I guess the operative question is that one shift actually takes you up from the natural circulation line up into the 30 million pounds per hour or something like that?

MR. KOTTENSTETTE: Yes.

MR. BROWNING: These guys look ahead and try and target those windows to make sure that they don't have a shift turnover right in the middle of some critical task in the middle here.

And our conclusion is that we have shown that the operation at the extended power uprate with respect to the thermo hydraulic stability has been acceptable. Next slide.

I get to continue on, and again with Jason, and this time we are going to talk about anticipated transients without SCRAM. We are going to go through and give you a little bit of background on how Duane Arnold complies with the ATWS rule.

And then Jason again is going to talk about methodology, and how we went through and did the calculations, and then I will get back up again and talk about the analytical results and the conclusions.

Again, to demonstrate that we have considered the operational and safety margins from the ATWS perspective at the EPU conditions. First, the system that everybody is most familiar with when we talk about ATWS, and that is the standby liquid control system.

For Duane Arnold, we have gone to the two-pump operation, where the single switch in the control room starts both pumps simultaneously. And they are required to pump a minimum of 26.2 gallons a minute each, and to get the equivalency requirement, we use naturally enriched boron.

And we use a minimum concentration of 11.8 weight solution of sodium pentaborate. That means the rule requirement for the 86 GPM equivalency that was spelled out in the rule.

And the other thing to understand is with our design being a BWR-4, we do inject the boron solution below the core through the sparger, okay.

We have installed the alternate rod insertion system, and one of the things that you will hear about in the conservatism and the way we do the calculation is that we take no credit for that in the analysis, which is the system that pneumatically bleeds off the air from the control rods, and allows them to go in as the back up.

We have the recirculation pump trip system, that when we detect conditions that would be indicative of an ATWS of a high pressure in the water level, the recirc pumps will trip off and run back to flow.

And that we have adopted the BWR Owner's Group emergency procedure guidelines for dealing with the ATWS, which include lowering the water level and taking those actions.

The ATWS rule established pretty much hardware requirements, and then behind it, we go back and we look at and demonstrate that we comply with the analytical basis that that rule was predicated on.

So the things that we look at are the peak pressure below the ASME service level of 1500 psi for the events. We demonstrate that the peak cladding temperature remains within the 50.46 requirements of 2200 degrees fahrenheit.

We look at the local oxidation fraction, and make sure that it stays below the 17 percent requirement of 50.46. We look at the suppressible temperature and ensure that it remains below the plant design limit of 281 degrees fahrenheit.

And we also look at the containment pressure to make sure that it stays below the plant design limit of 62 pounds. And then we go back and we benchmark to not the current power level, but the original license power level, which for us would be 50.93 megawatts, to demonstrate that the impact of the EPU is acceptable.

So we go all the way back to the original plan and do the comparison. And at this point, I will turn it over to Jason.

CHAIRMAN WALLIS: How close do you get to these limits when you do this? Let's say it is within 10 CFR 50.46, are you opening up against, say, 2200 degrees, or are you still a long way from it?

MR. BROWNING: We are a fair ways away.

MR. POST: We are a long way from it and

we are going to show you those specifically as well.

CHAIRMAN WALLIS: But you are closer than you were before?

MR. BROWNING: Yes, and we will show you the results later.

MR. POST: So this is Jason Post again. I have one slide here on methodology. We use the ODYN code when we did the first generic licensing topical report on power uprate. That was also the same time that we also submitted the application to use the ODYN code to do the ATWS calculations.

And ODYN, of course, has been used for a number of years for transients, but we had to get the approval of the various models that we needed for ATWS, and specifically the boron mixing model.

And the boron mixing model is the key conservatism that we have in the ODYN analysis, and we demonstrated that it adequately bounds the best estimate calculation with the TRACG code. That was our benchmark that we used.

It is important to note that we do use a best estimate approach for ATWS. Some of the conservatisms that we have in there are on the SRV subpoints. We do use conservative SRV subpoints in the calculation to compare to the peak reactor pressure criteria.

And we do use reasonable operator action times. It is important to note that the SLCS initiation, which is two minutes after the ATWS signal, has not changed. So someone made a comment earlier about how the operator response has decreased.

In fact, we use exactly the same operator action time that we used for power uprate, or that we would use for an ATWS analysis at current license power.

So it does -- you do have a slightly steeper uprate during those first two minutes, but we have not changed the operator action time. We use the same action time.

We use pool cooling and service about 11 minutes, and that is basically 10 minutes of nothing happening and one minute to align the system is where that 11 minutes comes from.

And as we have talked about before, this is supported by the emergency procedure guidelines, and the emergency procedure guidelines actions are fully adequate for EPU. There is on change to the basic actions that are taken in the simulator training.

CHAIRMAN WALLIS: Now, how is the level

controlled during this ATWS? Is the operator looking at the level in the vessel?

MR. POST: Yes, he is. We do do a water level reduction.

CHAIRMAN WALLIS: And isn't there some action to control that level?

MR. POST: One of the key mitigating features of an ATWS response is to lower water level below the feed water spargers so you don't have that low subcooling.

And actually you reduce clear down to the top of the active fuel to reduce the power level. Once you reduce the power level, then you are mitigating the stream that is going to the suppression pool for the bounding ATWS event.

So the termination of feed water happens in about the same time frame as the initiation of SLCS. They are both what we would call immediate operator actions in the power control portion of the guideline.

CHAIRMAN WALLIS: So with the uprated power, there is somewhat less time to do this?

MR. POST: Again, we make the same assumption on operator action time. We assume the time is the same. It does give you a little bit worst result, which you will see in a few minutes. But we are using the same time to take both actions or for both conditions I should say.

DR. POWERS: When you have analyzed these in the generic sense, or in the specific sense, either one, do you look at the pressure on the fuel rods during the water level drop and then the mixing?

MR. POST: It is not an explicit part of the calculation. Remember that during the water level drop, we maintain the core covered, and we do have a peak clad temperature calculation which shows that the temperature stays quite low.

I don't think the response to the fuel is any more severe than one of the transient events, the response for ATWS. The real threat from ATWS is the containment temperature. I mean, that is the biggest worry.

DR. POWERS: Here is what I am interested in, is whether any of the fuel rods having large stresses put on them or strains?

MR. POST: Not more severe than any other event in the envelope, in the design envelope.

MR. ROSEN: Well, you have got me a little confused now frankly. I am reading the staff's safety evaluation, and it is on page 75, and in that they are talking about the PSA and the screening that was done, which identified five operator actions that were evaluated for their impact on plant risk.

One of those actions is the initiation of SLCS for turbine trip and main steam isolation valve closure ATWS events. And in that paragraph, it says due to the extended power outrate, the early SLCS initiation timing is reduced from 6 minutes to 4 minutes; while the late SLCS initiation timing is reduced from 20 minutes to 14 minutes.

Now, just looking at the early, that says from 6 to 4 minutes; and yet your slide says 2 minutes.

MR. POST: Two minutes after the ATWS signal is what we use in the analysis, and I am not certain the basis for what is in the PRA.

MR. BROWNING: In the PRA analysis -- this is Tony Browning again. In the PRA analysis -- and we will speak to it later when we get to that presentation, those are actually acceptance criteria that are applied in the PSA model.

If the operator performs to that level by that time, the event tree goes in one direction. If he is not successful at that juncture, it takes a different path and goes down through the event analysis in a different way.

And that is really all that is driving there. It is driven by the map results, and the change in time, and the calculation of the human performance. But really what it is doing is setting up later in those events what the successful criteria is, or how much suppression pool cooling is required to keep the containment within the design.

MR. ROSEN: I understand that, and these results that are reported here by the staff have an effect on our probablistic safety analysis, and the impact of the change in power on the resulting core damage frequency.

MR. POST: Correct.

MR. ROSEN: And what you are saying here, I think, and help me to understand this, is that even though the PSA uses four minutes to draw some judgments about operator success likelihood, and that four minutes speaks to some analysis of the performance shaping factors for the PSA, in the thermal hydraulic analysis, you initiate SLCS in two minutes rather than four minutes.

MR. POST: Yes, we do. That's correct.

MR. ROSEN: It's different and I don't understand why.

MR. BROWNING: This is the basic -- if you will, deterministic modeling and methodology which -- like we said in the beginning, that is the basis for our application.

The PSA look was to look for risk insights, and you are seeing that. You are seeing the result of us looking with our PSA model for risk insights, and we have incorporated those.

That's why we went up with the simulator with the operator training early on and ran through these scenarios. And Mr. Kottenstette said he has discussed that earlier, and that we really did not see any degradation of human performance in the simulator.

That was the take away from this. We saw the result, and we got the lesson learned, and we went up to the simulator to see if in reality we were seeing a challenge to the operators, and if that had been the case -- and it wasn't, but had that been the case, and we had seen that, we would have had to make adjustments.

And that either at operator training or some other mitigative strategy, if the effect of the uprate had been that we needed to get standby liquid in much sooner, and we had seen a degradation of human performance in the simulator, we would have had to address that, but we didn't see it.

MR. ROSEN: I am puzzled, and a little troubled about using two different numbers; one in the PSA analysis and one here, for when you initiate SLCS. If you used the four minutes here to be consistent with what the PSA people do --

MR. POST: Our PSA expert is going to get up and address that.

MR. BOEHNERT: Come up to the mike and identify yourself.

MR. POST: But that is not uncommon. I mean, we have different ways that we look at things in deterministic space from the way that we look at things in probablistic space. It is not different.

MR. HOPKINS: This is Brad Hopkins from Duane Arnold. I am the PRA engineer at Duane Arnold. I think I can provide a little clarification.

In the PRA, we allow containment pressure and temperature to go much higher than the design values before we assume failure. So in our thermal hydraulic analysis, we are able to live with later standby liquid control injection before we would exceed our criteria.

The criteria is different because in the PRA our containment failure occurs at much higher pressures than the design pressure. That is, we would not expect containment failure until about 120 psi. Whereas, in the licensing basis, 54 psi. So that would account for some of those differences.

MR. POST: So you could allow a higher or a longer action time and still meet your criteria?

MR. HOPKINS: Yes. We are looking at or trying to look at realistic evaluations and not putting in the conservatisms that are applied for the licensing based evaluation.

MR. ROSEN: That clarifies it, but I would point out that you have the differences there.

MR. BROWNING: And as we get into the event, specifically with the results, and we were asked to look at the acceptance criteria and how we compare those, and do a comparison of pre-EPU to EPU results.

And then a recent topical issue, we are going to look at our Evaluation of Information Notice 2001-013, which was the inadequate SLCS relief value margin issue. This is a comparison of Pre-EPU to EPU, and if you look at the --

MR. BOEHNERT: Excuse me, but could you go back to the slide. Can you highlight that relief value margin issue, please?

MR. BROWNING: We will get to that.

MR. BOEHNERT: Fine.

MR. BROWNING: And first off we will look at the EPU results. You will see that the peak reactor vessel pressure, the acceptance criteria is 1500 pounds, and we are at 1343, and we are below that limit.

We are going to look at peak fuel cladding temperature against the 2200 limit, and as you can see, we are at 1380 degrees fahrenheit. So we are quite low there.

And the peak suppression pool temperature limit, the design limit is 281 degrees, and we are at 215.6 for the EPU; and the peak containment pressure, the design on that is 652 psi, and we are at 18.3. So as you can see here, we have lots of margin.

And looking at the impact of the EPU, again, reminding everyone that this comparison goes all the way back to the original rated thermal power of 1593 psig, you are seeing the impact of not only the full 20 percent increase, but you also are seeing the impact of reactor pressure change, and a ELLLA to MELLLA change as well.

Because at our previous uprate, when we did this stretch of 5 percent in 1985, that was when it raised reactor pressure. So you are seeing all those effects rolled up into this.

So the reactor pressure as expected goes up, and the suppression pool temperature and the decay heat goes up, and it takes the containment pressure with it.

The interesting result is the fuel cladding temperature. You see a slight reduction, and that is because of the flattening of the radial power in the core, and where the peak bundle isn't working any harder to bring up the average.

So we redistribute the flow, and the net result of that is that the peak bundle gets a little bit more flow because the average bundles are getting a little bit less because of the increased pressure dropped from their steam production.

So the peak bundle gets a little bit more cooling, and so the FCT comes down.

CHAIRMAN WALLIS: Do you actually have the acceptance criteria on this? You told us what there were, but --

MR. BROWNING: We have a back up slide with that if you would like to see it.

CHAIRMAN WALLIS: But you told us what they were.

MR. BROWNING: Here is the background on the information that was on the SLCS margins, and the concern is that in an ATWS event, and the loss of off-site power is the specific one that was addressed, the concern is that you have high reactor pressure at the time of standby liquid and ejection.

And you have reduced margins to the relief valve setpoint, and one of the things is that you have an operating margin that is required between the peak system pressure at the relief value next to the pump, and the nominal relief valve setpoint.

You have a required delta that you are required to maintain there. So what happens is that you are trying to account for uncertainties, a set point drift in the relief valve and other things, and also because these are positive pressure pumps.

And they are very dynamic, and you get big pressure pulses as it ejects, and so you are trying to absorb all that with this margin. And the concern is that if the reactor pressure is too high, it can eat into this margin, and you have the potential to interrupt the standby liquid ejection, and actually the circulate the boron in a loop around the pump, but not actually inject it into the core.

The results for Duane Arnold is that we

have grater than a hundred psi operating margin to the nominal valve set point, and we saw no interruption in the SLCS ejection.

In conclusion, we talked about the methodology and how we use that to capture margin, which we also go back and do at the benchmark to look at the impact of the EPU on the plant, and to look at the margin that would go there.

And then again in the plant specific results, we satisfied all the acceptance criteria, and so we saw no impact from the safety margin. If you have adequate margin for the acceptance criteria, we have operational margin sustained by that.

And then we have an acceptable comparison to the benchmark case, and so we didn't see a huge change there. So from that we can conclude that the operation of the EPU from the ATWS perspective is adequate.

DR. SCHROCK: What was this best estimate of the --

MR. POST: That was approved at the time of the ATWS rule and the first time that we started doing ATWS analysis. It is because of the low probability, and also because it was not part of the original design basis. It was an added analysis, low probability.

DR. SCHROCK: To put it in the context of best estimate analysis, can you put a date on that for me? Was it the early '80s?

MR. POST: I don't remember when the ATWS rule came out, but --

DR. POWERS: Around '85 or '85.

DR. SCHROCK: And ODYN was its basis at that time?

MR. POST: No, at that time we were using a READY code, and as I said earlier, we didn't -- ODYN had been used for the transient calculations, but we had not qualified the boron mixing model until the time that we did the generic submittal on power uprate in the mid-1990s. That's when we started using ODYN for ATWS calculations.

DR. SCHROCK: And in the original ATWS problem, you didn't present it as a best estimate calculations?

MR. POST: Well, I am sure in the original analysis that was done with READY, and the ATWS rule compliance, I am sure that those were done as best estimate calculations. Yes, I'm sure that they were.

DR. SCHROCK: I don't remember it getting reviewed in that time frame, but it must have been.

MR. BOEHNERT: I remember his argument, and I remember that they did a lot of that as he said. I believe it was ODYN, but I don't really remember.

MR. POST: There were a couple of very large topical reports that GE wrote on the ATWS response for various events, and trying to determine what the limiting events were and that needed to be analyzed, and what the assumptions for the analysis should be.

And I know that those were presented to the NRC, and whether they were actually presented to the ACRS, I am not certain.

DR. SCHROCK: Well, I am just curious to know a little more about what is in the ODYN one.

MR. POST: All right. This is ATWS instability, and we talked about the instability prevention to ensure that you prevent an instability, and if it does occur, you do get an automatic SCRAM to show the reactor down and terminate the oscillation.

But one of the concerns previously was what happens if that SCRAM fails, and so the oscillation continues to grow and it is not terminated, and how bad does it get.

And so I am going to talk a little bit about the background, and the methodology, and what happens to an ATWS instability if you don't have mitigation, and why the application for Duane Arnold is acceptable.

And again we are trying to demonstrate that the existing ATWS instability analysis, which was done for a high power density plant with MELLLA is adequate for the Duane Arnold extended power uprate.

So there were two topical reports written and that were both reviewed simultaneously by the NRC, and one SER was written on both reports. The first one is the NEDO-32047, which is the ATWS rule report.

And the purpose of this report was to determine if fuel rod failures are unlikely from a worst case instability event with the SCRAM failure.

And the result of the evaluation was that this had no mitigating operator actions of any kind, and so it maintained water level high in the reactor and so it maximized the power production.

And we found that the power spikes become very tall and narrow. It is almost like a reactivity excursion type of event, in terms of what the fuel experiences. It becomes -- so the peak energy deposition, and we found it is within the fuel design limits as you would get for reactivity excursions.

But the power becomes more severe as the core inlet subcooling decreases, and in fact you get to a point where as the subcooling decreases that you actually get a power spike that causes an extended dry out, and where the fuel doesn't re-wet in an oscillation.

And when you get that extended dry out of fuel service, then you get a very excessive clad temperature, to the point where a portion of the fuel could fail, and so we calculate that the number of bundles that this could happen on, and the actual location of the bundles. And it is about a half-a-percent of the core volume.

DR. POWERS: When you say that it is within the fuel design limits, you mean that it is less than --

MR. POST: That's correct.

DR. POWERS: And that is if it is fresh, but how about if it is burned up a bit?

MR. POST: I think we are at around 70 or 80 calories per gram, and --

DR. POWERS: And can it tolerate that when you --

MR. POST: I am going to call on Dr. Jens Anderson. Jens, would you mind helping me with this?

DR. ANDERSON: This is Jens Anderson to

talk about that fuel. When you get these high powered oscillations, you get those in the fuel bundles from high radial peaking. High radial peaking will only occur for fuel with low exposure.

Once you get to the higher exposure, two things happen. First of all, you don't have as much activity left in the fuel and so you don't get the higher radial peaking, and that was actually analyzed as part of this work that was done in the first report, the NEDO-332047.

And it shows us that as you go down in radial peaking, you cannot get these high powered oscillations. Secondly, this is very -- the other things that happen is that even if you have high flux peaks, with lower activity in the fuel, you don't get the power response.

So I think the short answer is that you can get the high oscillation for fresh fuel, but for highly exposed fuel, you cannot have the high power oscillations.

MR. POST: Again, this is the event and the results that were analyzed previously, and what we are demonstrating or discussing is the fact that those were adequately severe in the analysis that was done already, and did not get any worse for the MELLA EPU condition for Duane Arnold.

So we are discussing things that were already presented, and so it is not a new consequence.

CHAIRMAN WALLIS: It has already been judged then as an acceptable --

MR. POST: Yes, and again this is the no mitigation result. I mean, that's why we had EPGs, and this is intended to demonstrate the worst case -- no mitigation, maintaining water level high, letting subcoolant go dry, and how bad does it get, and that is what that report was intended to show.

And there could be a larger fraction of the core. The .5 percent may not be a valid number. It may go up to one percent. I'm not sure exactly b because of the flattening, and the radial power distribution, and you have more bundles that are closer to the limit.

So I would agree that the .5 percent that was reported in that report was based upon the core design at that time. So that could get a little bit worse, and frankly we have not calculated that.

DR. SCHROCK: And the most immediate consequence is that gaseous fissure products are released from rods that have failed.

MR. POST: Yes, certainly.

DR. SCHROCK: And it would seem to make more sense to express it as a fraction of rods failed, as opposed to fraction of core volume failed.

MR. POST: That was the way that it was expressed originally. So if I can continue with the next report, which is the mitigation report, 32614. What this one did was recognize that that condition is not acceptable.

You certainly would not want to have your plan operate there, and get into that condition. So they looked at what are effective mitigation strategies.

And the two that are reported are as most effective, one is to lower the water level to below the field water spargers. Now, of course, the EPGs say lower it to -- there is two levels approved by the NRC.

One is to five feet above top of active fuel, and the other is to the minimum steam cooling water level, which is actually below, a collapse level below the top of active fuel.

But to mitigate the ATWS instability, you don't have to get it that low. That gives you a bigger power reduction, but the key thing is the subcooling, in terms of the instability.

You only have to get it about one or two feet below the feed water spargers in order to have the water that is coming in spray into a steam space, and raise the temperature enough so that you mitigate the core and let sub-cooling.

So that can be accomplished very quickly with feed water run back, and that gives a real quick water level reduction. And it eliminates, completely eliminates the large power pulses.

Now, you can still have a small oscillation that continues, but these very large dramatic power pulses are completely eliminated. The other feature is the boron injection, which is of course also specified in the EPGs.

And boron injections is very effective for the long term shutdown, but it is not quick enough to prevent the kind of extended dry out that gives the fuel rod failures by itself.

It does eventually make the oscillations go away completely, but it doesn't happen -- the delay time from the time it was initiated, and to the delay time until it actually gets into the reactor core, and until it mixes, and until it shuts down enough to terminate the oscillations, it just does not happen fast enough. So the water level reduction is the key.

And the methodology we used is TRACG, and which you have reviewed before. We use multiple channel groups and it gives you a detailed 3-D kinetics in the thermal-hydraulic model of the core. It is a very effective model for doing this.

And then the next chart there is a benchmark from -- it is a current calculation of the repeat of the case that was in NEDO-322047, and you can see here the type of power spikes that were reported in NEDO-322047 and that go up above a thousand percent.

And as subcooling continues to decrease then, you are kind of reaching a maximum of your subcooling at about 200 seconds, and that is where if you go to the next chart on the peak clad temperature --

CHAIRMAN WALLIS: And that has been going along for quite a long time hasn't it?

MR. POST: Yes. Right. And this is again where the operator isn't -- you know, this is assuming that whatever actions the operator has taken to try and insert control rods have been completely ineffective and the water level has not been reduced.

DR. POWERS: And is this level for the fuel cycle?

MR. POST: I don't remember exactly. I'm sure that it is at the most reactive point in the cycle. It is probably around the middle of the cycle is probably when it is done.

And again they are very conservatively bumping up the radio peaking factor to make sure that they get it. So the next slide talks about the ATWS instability with mitigation.

Now, I don't have a chart to show that, but what happens is that at about 150 seconds, feed water -- the core in-let subcooling turns around, and the oscillations start to die back down again, and you don't get anymore of those huge random power peaks up to a thousand percent.

CHAIRMAN WALLIS: Well, you have showed us the bad looking ones, and it would be very good if you showed us the good looking one as well.

DR. POWERS: And even so, within the first 150 seconds, you are putting some pretty good pops into that fuel. I mean, even before the 150 seconds.

MR. POST: Well, I didn't have an electronic version of that available, and so we will go to the old paper method. But this shows how the core -- the base case about mitigation is that subcooling continues to increase and it goes up to about 60 degrees K, and then that is about here, and about 200 seconds is where they just keep going along and this is where the dry out occurs.

And with the feed water reduction, the water level reduction below the feed water spargers, you get a very effective turnaround of the subcooling, and you can see that we don't like these kinds of oscillations, but they are enough so that they stay within the capacity of the fuel.

CHAIRMAN WALLIS: And it is counter-intuitive, and if you make the water colder, you think it would cool better. But in fact it makes the oscillations worse.

MR. POST: That is correct. Warmer water gives you a better response from the hydraulic instability.

MR. ROSEN: As long as you have raised the question of counter-intuitive. From an operator perspective, Steve, a little bit counter-intuitive, isn't that to lower the water below the feed water sparges?

MR. POST: As far as auxiliary power?

MR. ROSEN: Are you trained to do that?

MR. POST: We know that we lower power or reactor water power reduces with it.

DR. KRESS: And it is not so counter-intuitive for BWRs in other words.

MR. MCGEE: It is not counter-intuitive.

MR. POST: In nearly every training scenario, they will have some sort of ATWS scenario, and they are trained as to that.

MR. ROSEN: So you are modeling this in the simulator, the compliance simulator is that you are saying?

DR. KRESS: No, this is TRACG.

MR. POST: This is TRACG.

MR. ROSEN: No, I am saying that you are modeling this event.

MR. POST: If I maintain water level high, I will still see the high power because I am not getting the increase in subcooling going on. So I know that it is going to be a longer scenario for me because power is going to be higher.

MR. ROSEN: So in your simulator crews are trained to run feed water back and get the core level below the sparges.

MR. POST: That's correct. The operator action is to lower the water level all the way to the minimum steam cooling level, which is near the top of the active fuel, and which is well below the feed water sparges.

So they don't stop when they clear the feed water sparger. They are running it all the way down until they get power to clear the APR and down scale --

MR. ROSEN: Is this one of the critical actions in the operator training?

MR. KOTTENSTETTE: It is a critical task for us to lower the level down to a certain point, and for us it is 87 inches above the top of the active fuel. At that time, we have a decision to make; is power now less than five percent power.

If it is, then now I have arranged to maintain water level from the top of active fuel up to whatever that water level is that the power is less than five percent.

DR. KRESS: Would you go back to your slide on the peak cladding temperature without mitigation that you had up there. Yes, that one. No, the next one.

What is happening to the center line fuel temperature during this process? Do you have an equivalent curve for the center line fuel temperature in that slide?

MR. POST: I do not have that available.

It wasn't included in that report I don't believe.

DR. KRESS: But does it oscillate or does it have a steady rise because of the lack of good coupling, the thermal coupling between the clad and the --

MR. POST: Well, I am sure that it is oscillating on this same kind of frequency as well. So I am sure that it is not a steady temperature. I mean, the surface heat transfer coefficient is varying as the fluid conditions changes at the surface.

DR. KRESS: But your thermal conductivity and the fuel is not varying very much, and it is a pretty good heat capacity in those fuels compared to the clad, and I was mentally thinking that you might get some oscillations, but you have got a steady rise in that --

DR. POWERS: The fuel looks like a bunch of stair steps.

DR. KRESS: Yes, but not little or big stair steps. But I was trying -- what I am thinking, Dana, is the total deposited energy in the fuel itself compared to this limit of how many calories per gram you get, as opposed to what you get in one oscillation.

DR. ANDERSON: This is Jens Anderson

again. What you can see in this plot prior to 200 seconds is that you have repeated boiling transitions and reword, and in that period the heat removal, the net heat removal from the surface of the fuel rod, is the same as the energy generation.

So, yes, you get some oscillation in the center line temperature, and the center line temperature is higher than the cladding temperature, and on average it is constant.

DR. KRESS: It's not steadily climbing up then.

DR. ANDERSON: No, it's not. It doesn't start climbing up steadily until you fail to leave it, and then you go up to a higher clad temperature, and a correspondingly higher center line temperature.

DR. POWERS: I cannot believe that in two seconds that you thermally communicate with the center line of a fuel rod.

DR. KRESS: That was my problem.

DR. POWERS: And I would find that remarkable, especially with a BWR rod.

DR. ANDERSON: No, that's correct, and you are going to have a significant face shift between the center line temperatures and the surface, because the fuel is time constant.

Some are time constant, and the fuel is typically in the order of 6 seconds, while the period of the oscillations are more like 2 seconds. And which tend to give a fair amount of damping in the temperature response.

CHAIRMAN WALLIS: Were you adding boron to the water at this time?

DR. KRESS: No, this is no mitigation.

CHAIRMAN WALLIS: No mitigation at all? So what is the long term prospect?

MR. POST: The long term prospect is --

CHAIRMAN WALLIS: How does it eventually shut down?

DR. POWERS: That is a special plot that shuts it down.

MR. POST: Well, that's why we move around a little, but then this is the effect of boron mitigation.

CHAIRMAN WALLIS: Eventually you want to raise the water level eventually.

MR. POST: Well, not until you get the reactor shut down.

CHAIRMAN WALLIS: You have to get some boron in there or something.

MR. POST: Yes. When you get the boron in the oscillations go away completely.

CHAIRMAN WALLIS: That's right.

MR. POST: So this particular plot has only the boron injections, and so if you did the water level reduction by here in 150 seconds, you would make all these power spikes go away.

And then as you would continue to inject boron, you would make them go away completely. So it is a combination of the two that allow for getting rid of those oscillations and --

CHAIRMAN WALLIS: It is this drop in the level that is just to shut down the neutronics, and so it is counter-intuitive from the point of your cooling, but it is what you need to do to shut down the nuclear reaction?

MR. POST: That's right.

CHAIRMAN WALLIS: Then you need to get some boron in for the long term.

MR. POST: It mitigates the containment response dramatically, as well as avoiding this type of power spikes in the fuel.

DR. POWERS: Graham, not everything is thermal hydraulics.

CHAIRMAN WALLIS: No, it's not. I think it is great.

DR. ANDERSON: This is Jens Anderson again. I would like to point out one thing, is that the curves that Jason Post has shown is what you have is when you have an ATWS, the high density plant at the middle line. It is really not an easy EPU issue.

DR. POWERS: Well, we don't have analyses for this plant at the high and the low power levels to see what they do.

MR. POST: And you are right, we do not have that. Because the MELLLA boundary had previously been analyzed and the peak bundle power for Duane Arnold is consistent with what the bases were that were performed, we have done some GE14 studies to confirm the GE14, which is the newest fuel design that they have already loaded, I believe.

And the response for GE14 is similar, and the ATWS mitigation techniques are still effective, and so we did not do a Duane Arnold specific TRAC calculation for this.

So the methodology, it evaluates the margin and it uses limiting initial conditions, and limiting peak bundle powers. And there isn't really a safety margin associated with this. We are past the safety margins for this particular evaluation.

There is no degradation of the fuel

response for EPU. We already have a pretty severe response, and so the margins that you had before are sustained. So from this point of view, EPU is acceptable for Duane Arnold.

DR. POWERS: Are there any questions on this portion of the program that we have gone through so far? Seeing none, and not looking very hard for any of them, I am going to call for a recess until 10 of.

CHAIRMAN WALLIS: And during the recess, I would like to respond to the question that I raised about capacity, because it may be just a misunderstanding.

(Whereupon, at 2:37 p.m., the meeting was recessed and was resumed at 2:50 p.m.)

DR. POWERS: Let's go back into session. We are now going to move on to the non-controversial topic of the corrosion. I know that there will be no questions at all, and so we will be able to whip through this topic with speed and direction, I'm sure.

MR. SEVERSON: I am Russ Severson, and I am here to discuss our flow accelerated corrosion program at Duane Arnold, and what the impact will be from what I expect the impact is from the extended power uprate.

To quickly explain flow accelerated corrosion in five seconds, flow accelerated corrosion leads to wall thinning, and many perimeters, including water chemistry, material composition, and the hydrodynamics effects, affect this wear rate.

And, of course, carbon steel piping is a especially susceptible material. Duane Arnold has had a long term monitoring program focusing on the susceptible high-energy carbon-steel piping system.

We include both single and two phase systems throughout the balance of the plant site, and at DAEC, we completed a tailored collaboration with EPRI back in the mid-1990s, which helped us base line and determine what our modeling was and to evaluate what should be modeled, and what our inspections should be.

And we have been progressing with that base line inspection. All our lines are continuously operating lines, and are modeled in our EPRI CHECWORKS program.

The inspections are performed to verify their model and to monitor the wear specifically. We typically do 40 to 60 inspections or actually locations. We inspect locations.

CHAIRMAN WALLIS: To verify a model, do

you actually do enough readings to verify a model?

MR. SEVERSON: To verify this model? Yes.

CHAIRMAN WALLIS: So you actually have a prediction at the rate at which --

MR. SEVERSON: We have a prediction, yes.

CHAIRMAN WALLIS: And it works?

MR. SEVERSON: Of where it is, yes, and of our different rates within our continuously operating lines. And in that prediction, what we had to do was we went back and evaluated the beginning of the operation, and decided what our wear rates were through all 18 at the time, or 15 cycles of where.

And to evaluate what our chemistry was through all those 15 cycles, and how we operated, and we have a heat balance, a simplified heat balance within the program to identify what the hydrodynamics are.

And adding all of that up, we do these inspections. Now, we didn't start out doing 40 top 60 locations. That is now after many years of having this model and verifying, and ensuring that it is correct.

CHAIRMAN WALLIS: So now you have enough information that you can safely scale it up to higher velocities.

MR. SEVERSON: Correct. Originally, I think we did around like 200 inspections the first time we put the model together. But since then, we have been having to do less.

DR. FORD: Is it qualified for the higher flow rates? By qualified I mean there are data for the higher flow rates?

MR. SEVERSON: Yes, there is. Within CHECWORKS, it will let you vary the feet per second wear rate within your systems. Our plant has by design fairly low flow rates. And so with the 20 percent increase, you are within the boundaries.

DR. FORD: And are there other data of what the CHECWORKS flow rate would tell you?

MR. SEVERSON: Well, within their book that they publish with EPRI, they show graphs of up to 40 inches per flow rates, and I don't know if some plants have this or not, but I do know that Duane Arnold is a low wear plant, and that is partly because we were built with larger pipe diameters than what they built with some of the later model plants.

DR. POWERS: And one has to recognize that CHECWORKS has an empirical database that extends well beyond just the nuclear business.

MR. SEVERSON: That's correct.

CHAIRMAN WALLIS: Could I ask if Susquehanna is one of the plants with higher flow rates, the reason being that they have had erosion problems? I understand that they are going to have a limited power uprate.

MR. SEVERSON: It is in the model. I have not had data back from Susquehanna that they wouldn't have had and that CHECWORKS would not have worked.

And I can't tell you as to what extent they use CHECWORKS at Susquehanna, and so I can't speak from that qualification of knowledge. I do know that within our flow rates there are plants out there that model lines that will be at these newer flow rates, 20 percent higher, and they have not seen that issue.

And I would have to see what the Susquehanna issues are. I am not sure if they are a reheat plant, or a second reheat plant like we are, which makes a huge difference into your wear rates.

CHAIRMAN WALLIS: And the fuel piping, has that been exposed to --

MR. SEVERSON: That is correct.

CHAIRMAN WALLIS: And those carbon steel pipings have been exposed to --

MR. SEVERSON: To the feeder water lines, yes.

CHAIRMAN WALLIS: And the feeder water lines are checked?

MR. SEVERSON: Yes, and those are the ones that I tried to provide data on since they are the ones that can show you the velocity changes since -- and some of our other lines were going to a less -- to a higher quality line, and less wear from the quality standpoint of the steam coming in.

CHAIRMAN WALLIS: And versus the observation?

MR. SEVERSON: Yes.

CHAIRMAN WALLIS: And also for the platinum covered carbon steel?

MR. SEVERSON: I have not seen with the platinum covered carbon steel as to -- well, I have not seen where CHECWORKS significantly differs yet on wear rates.

Now, one thing about flow accelerated corrosion, which is that it is a very long term phenomenon, and I am modeling history back to '75, and we have had none since '96, and so far the Noble Chem has not shown a significant difference.

DR. SHACK: But those lines at Noble Chem, those would be very low flow accelerated corrosion.

I mean, aren't they the ones that just sort of sit there? The carbon steel lines that actually see Noble Chem.

MR. SEVERSON: Not in the high flow rates. Go ahead.

MR. KNECHT: This is Don Knecht from GE. The feed water -- the carbon steel feed water lines do not see the Noble Chem injections. It is only the stainless steel.

MR. SEVERSON: Yes, it should not have come back that way, because they do it with the recirc.

CHAIRMAN WALLIS: CHECWORKS predicts a continuous variation of wear rate versus velocity or something, or is there a transition, and a critical velocity? What sort of dependence is it?

MR. SEVERSON: They have an empirical formula of -- I will throw up a slide here to give you a feel for what the impact of the velocity is.

CHAIRMAN WALLIS: Is it velocity to some power or something? So it is a continuous behavior. It is not a step chain. It is level or something? I mean, downstream of a connection, it is not --

MR. SEVERSON: There is another one, and that is true, too. In CHECWORKS, they have a certain factor formula. Let me throw that up.

DR. SHACK: And that's where you would see dramatic changes if you suddenly went through some sort of a transition, but this is kind of a -- you are in the same flow mode.

CHAIRMAN WALLIS: It is probably the boundary that matters, and if the high velocity gets right close to the boundary --

DR. POWERS: You have to understand in the middle that they really can't calculate anything, and so they develop this incredible empirical library, and it is called CHECWORKS.

MR. SEVERSON: And we are constantly doing testing and we use French data, and what have you. Here is the formula to give you a feel.

CHAIRMAN WALLIS: The geometry effect is this fudge factor G.

MR. SEVERSON: And from their experimental evidence they apply this geometry effect, and what I just showed you was an effect that they provide. This is what is in the CHECWORKS model for liquid velocity changes.

This is by keeping the other issues constant, and here for the BWR is the oxygen level. It is a very low oxygen level for what this graph is showing.

DR. SHACK: What is the normal oxygen level in your feed water?

MR. SEVERSON: Right now, 30 parts per million.

DR. SHACK: Now, when you change out your high pressure turbine, and is chrome moly steel, or are you stuck with the associated lines?

MR. SEVERSON: A couple of them have already been changed with chrome moly steel, and a couple of them will remain carbon steel. The ones that I have not been seeing with significant wear.

And a couple of them were the old alloy -- the copper based alloy that we as a plant have not seen significant wear in, and there is a smattering of different lines throughout that we watch.

DR. KRESS: Why do those curves peak at a given temperature?

MR. SEVERSON: Why do they change in temperature?

DR. KRESS: No, why do they peak?

MR. SEVERSON: Why do they come like this and come back down?

DR. KRESS: Yes. Why do they come back down?

MR. SEVERSON: Because flow accelerated corrosion is a temperature dependent phenomena.

DR. KRESS: I know, but I thought it would have just kept going up.

CHAIRMAN WALLIS: There is no why about any of this. It is empirical.

MR. SEVERSON: Well, around 300 degrees is your highest wear rate for flow accelerated corrosion with everything else said.

DR. KRESS: But my question is why is this?

DR. POWERS: It is the solubility data from Oak Ridge.

MR. SEVERSON: He's exactly right.

DR. SHACK: It is solubility.

DR. KRESS: It is dissolving the oxide off of it.

MR. SEVERSON: Yes.

DR. POWERS: It is solubility for EPRI 304, and goes through a maximum, and that is what underlies those curves. That was figured out by the chemists.

Now, the metallurgists came along and they said that in order to do anything they had to put fudge factors in because they can't calculate anything.

CHAIRMAN WALLIS: So it is washing away the rust.

DR. POWERS: Yes, washing away the rust.

CHAIRMAN WALLIS: Now I understand.

MR. SEVERSON: Now, we already went through this, and let's go on to the next slide.

CHAIRMAN WALLIS: Well, you have predicted what the change will be and it is going to be very small presumably. Is it?

MR. SEVERSON: Yes.

CHAIRMAN WALLIS: What sort of change do you predict?

MR. SEVERSON: Down here at the end, we will show you. It is about half to 1-1/2 mills, depending on where you are within the system because of temperature, and flow rate because of the size of the geometry.

So what I did was that I took the highest flow area in the feed water, and I took the worst temperature case in the feed water, and did a parametric study and showed what the differences were.

And this is about a half to one-and-a-half, where we are seeing about four mill now, and so we should be seeing about 5-1/2 mill, which with the piping, we will have about 150 mill margin to code allowances.

CHAIRMAN WALLIS: In a hundred years?

MR. SEVERSON: No, at 25, I think, or 30. Let's go to the next slide. So as I would conclude that we will monitor what the water rate changes are with the power uprate, and with the increased velocity.

CHAIRMAN WALLIS: Where does all the water waste go? Does it actually stays in the solution, and just deposits somewhere else?

MR. SEVERSON: It ends up in the condensate polishers.

CHAIRMAN WALLIS: Does it build up in other parts of the system?

MR. SEVERSON: Yes, you will see it throughout. And we found direct actual evidence with our chemistry numbers with iron, and we found actually a pretty good correlation as to what our wear rates are compared to the iron is at the end of the feed water.

DR. POWERS: You don't have any regions where you have corrosion product build up that is going to strip off, mechanically strip off?

CHAIRMAN WALLIS: A piece of scale that

will then wrap around?

MR. SEVERSON: I don't believe that we will have any impingement problems. Is that your issue?

DR. POWERS: I was just thinking of the Surry incident, where they stripped some oxide off mechanically because they jacked the flow rates up.

MR. SEVERSON: I don't see that. We are not in those flow rate ranges, and I think that's where these max numbers are. But we are like going from 16 to 18 feet per second generally.

DR. POWERS: So you are really quite low.

MR. SEVERSON: Yes.

CHAIRMAN WALLIS: Are we talking about flow reduced vibration in your analyses, too? I would think that reduced vibration would affect where, too, because of the boundary areas change when you oscillate the things.

MR. SEVERSON: Well, I don't think that this --

CHAIRMAN WALLIS: And then the reduced vibration would affect that.

MR. SEVERSON: I don't know if we have seen that, but I don't know if that phenomena really exists.

MR. ROSEN: When you estimated 25 years of margin, that was for beyond the 40 year? In other words, a total of 65 years?

MR. SEVERSON: That is from now. That is about from now with -- well, the differences that I am seeing in wear rate, I probably would not change my designs from when I think we should change by about, and depending if we went another 60 years, or another 10 years, I would probably have about the same numbers, whether we had a power uprate or not.

Because the wear rate right now until when we do a piping change, or decide to do a piping change, is not that much of an added effect, compared to what we have had since the beginning.

In actual fact, I think our chemistry probably in the early days wore us more than what we are going to wear now with a power uprate.

MR. ROSEN: You are saying, I think, that if Duane Arnold were to get or to come in for a license renewal that it would do it at the higher power level which it is now asking for, and not have to plan a piping replacement. Am I correct?

MR. SEVERSON: Not in this area. I don't believe so in feed water, and in some other areas, we are probably going to be doing pipe replacements anyway.

But some of the other areas that we were looking at, like some of the extraction steam lines are actually going to be improved under a power uprate, but change them anyway just because of where we are at.

But overall the majority of the piping will not be affected by a power uprate, and what we are going to decide to do, and what we are going to decide to change out, won't be affected.

I can't answer your question directly partially this is a continuously monitoring program, and we have done some pipe replacements, and we will probably do some more because of varying different reasons. And some of the reasons that we do pipe replacements is because we don't want to inspect it anymore.

We know that if we put in a better piece of pipe that I can reduce my inspections, and I can save money that way. But I don't consider that the EPU will have much effect on the decisions that we make.

MR. PARK: Good afternoon. My name is Gary Park, and I am the ISI Program Engineer for the Duane Arnold Energy Center. I administer all the inspections that we do on the reactor vessel, and on our ASME Section 11 components.

The first slide that I would like to talk a little bit about is about the program that we have at Duane Arnold. I think we have a pretty aggressive ISI, IVII, program, and IVII being internal vessel and internal inspections.

If you will notice for the Class One components -- and I have only counted back to 1985, but by the year 2005, we would have done 1,875 inspections just on the Class One systems.

And so the power uprate as far as the effect on the structural integrity of these components, we have already got a pretty good base line inspections for those.

The thing that I need to bring out about the inspection program is the fact that we find problems before they actually exist to a failure. We also utilize in our inspection program the recommended inspections of the boiling water reactor vessel internals project.

And I hope that everybody on the panel or on the committee is familiar with that, because I am sure that you have been addressing different safety evaluations from that particular group of utilities and their recommended inspections.

I think one of the materials that we should address in this presentation is the stainless steel materials that we have inside the reactor vessel.

Again, we perform the recommended inspections of the BWRVIP, and we follow all of their documents, and we have a pretty aggressive program in doing so.

For example, the course route, we have inspected all the H-1 through H-7 wells twice since 1985, and we have not found any IGSCC, intergranular stress corrosion cracking, in any of those welds.

So that shows that we have a good base line prior to power uprate in a particular important component that the industries have been finding problems with.

DR. FORD: And on that particular item, it is true isn't it that most of the VIP disposition curves, et cetera, have not been obtained, or are not based on data rather at relevant flow rates?

MR. PARK: The recommendations made from the VIP is in fact on safety and not based on any pressures or temperatures. It is just based on if that component fails, where are the areas that we should inspect.

DR. FORD: But are the frequency of your inspections based on disposition curves?

MR. PARK: I am not quite sure I understand what you mean.

DR. FORD: Well, what are the inspections based on?

MR. PARK: It is based on material and your --

DR. FORD: And if you find a crack?

MR. PARK: Then you increase your frequency, yes.

DR. FORD: And the frequency is dependent on the degradation rate?

DR. FORD: Sure. Sure. And crack growth rate would be one of them, yes.

DR. FORD: My point is that most of the crack growth rates which go into deriving what those disposition curves are, are being based on data not at high -- well, do you understand what I am saying?

MR. PARK: Well, I understand what you are saying. I don't know that I know the answer to that.

DR. FORD: I guess going back to the very first slide, "Inspection Programs finds problems prior to failure."

MR. PARK: Right.

DR. FORD: And which assumes that you are inspecting --

MR. PARK: At a frequency, that is correct. That is correct.

DR. FORD: And that is the origin of my words. And it goes on to the next question, and talking about DAEC performing examination of vessel internals, and we are particularly interested in IASCC/IAGSC.

It was mentioned earlier that the profile has changed.

MR. PARK: Well, I will defer to Tony on that, but it is more flattened out, but it has changed some.

DR. FORD: And therefore the pressure at the core shroud has increased?

MR. PARK: Yes.

CHAIRMAN WALLIS: Do we know how that will affect cracking at the core shrouds, and at that prior flux, and therefore fluence, especially if you are going to extend -- the fluences are all going to increase at a higher rate?

MR. PARK: Yes, and there is some threshold and that's when IASCC starts, and I am not sure where we are at as far as Duane Arnold. I think we are approaching that.

MR. BROWNING: This is Tony Browning again. We have already exceeded the VIP threshold for IASCC in like the top guide area in the upper shroud area. The other thing you mentioned was the increase in fluence.

One of the things that we noted when we did the fluence calculation was that the increase to the shroud area wasn't as dramatic as you were expecting, and that was because of the partial rods from the GE-14 design that we were going to. There is just less neutrons there. It is not as dramatic as the uprate itself.

MR. PARK: And then I think the other important thing to note is that we have done probably the highest percentage of any inspection that is done on these particular welds, and we have not found any cracking at all.

So we have a real good history of water chemistry, and then as I will address in a later slide, we have done the mitigation measures to help support and continue operation of that.

In fact, that is a good lead into the next slide. Duane Arnold has implemented hydrogen water chemistry which protects our recirc piping, which is stainless steel, and we were the lead plant in the industry in getting a relief from inspection frequencies based on the results of our hydrogen water chemistry.

And as we have continued to do inspections, we continue not to find anything, and so we believe that HWC is effective in mitigation of IGSCC in our stainless steel piping, particularly our recirc piping.

And then in 1996, which has already been mentioned here on the committee, we were the pilot plant for the Noble Chem, and we have since injected Noble Chem another time. So we have injected twice, which does enhance the effectiveness of HWC in protecting the reactor internals.

DR. FORD: Which is of importance in monitoring, and not just crack monitoring, but environmental monitoring. Remind me, but at Duane Arnold do you have corrosion potential monitors in the core?

MR. PARK: We have installed those, and we do have a caste system that is external that has reactor fluid in it, reactor water that runs through it.

DR. FORD: The reason for my question is not quite the answer to the question that I asked. My concern is that, yes, you have Noble Chem, and yes, it will stop cracking in the core, but the question now is that if you increase the flow rate in the core is there going to be any additional danger by that one action of increasing the flow with Noble Chem?

And that to a certain extent is only going to be answered if you have corrosion potential monitors in the core.

CHAIRMAN WALLIS: Well, that hasn't changed, the core flow hasn't changed in the power uprate. That is only the feed water and the steam flow that have changed. The core flow stays the same doesn't it?

MR. BROWNING: But back to your earlier question, and this is Tony Browning again. We do have in core monitoring. We replaced one of the LPRMs streams with the ECP monitors at the time.

MR. PARK: We have done that in the past, yes. They don't last very long as everybody knows.

MR. BROWNING: Right.

MR. PARK: But we have done it in the past.

MR. BROWNING: Yes, to demonstrate the

effectiveness of the Noble Chem injection.

MR. PARK: Right.

MR. BROWNING: And as Gary pointed out, we have the external cracks verification system, the outer clave with the pre-crack specimens in it to monitor the effectiveness of water chemistry.

MR. PARK: Before I got to my conclusions, I think I will turn some time over to Mr. Al Roderick to answer the stress question that was brought up earlier if I may, and we have an overhead of that.

MR. RODERICK: I am Al Roderick with Duane Arnold. The question that was raised earlier was based on a review of a response to a staff's REI in the area of stress analysis.

In looking at the main closure flange from current to EPU, I believe if you do the math of that, I think it is about a 12-1/2 percent increase that has been evaluated. What that is a result of is from GE's methodology in looking at EPUs, is to not redo a complete code stress analysis for the vessel.

They have in their methodology is the determination of scaling factors based on changes in perimeters from the code of record, or the calc of record, to the EPU conditions. It could be in the area of pressure, temperature, flow rates, particularly with flow rates with impact nozzles.

And they determined the stress of the scaling factors that would be applied. And they don't do it on an individual component basis. When looking at the reactor vessel, it is split up into zones if you go back and look at the original diagrams for defining operating conditions.

And so wheat they did was to conservatively apply the maximum scaling factor that came out of a particular region in the vessel, and as I pointed out earlier, as you are going back to the calc of record where the stresses are coming from, and in radioing up the EPU conditions.

So I don't have the specifics of what all fed into the 12-1/2 percent, but it is based on a conservative screening methodology for a good description, because it is a first cut, and it is applied to the entire stress intensity.

It is not usually split out in terms of pressure thermal mechanical loads, et cetera. The highest ones apply to the total stress intensity to get a conservative extrapolation or prediction of the stress, that is then compared to the code allowables.

And because all the code allowables were met, nothing more detailed or refined was done.

CHAIRMAN WALLIS: Are you saying that the reason that there is a 12-1/2 percent difference from current to power uprate is because a different method is being used?

MR. RODERICK: We are not using a detailed computer or code calculation. We are using a scaling --

CHAIRMAN WALLIS: So then the 12-1/2 percent is somewhat illusionary?

MR. RODERICK: It is based on changes in parameters, and I don't have all the details.

CHAIRMAN WALLIS: I would think the main closure flange is mostly influenced simply by the pressure in the vessel isn't it?

MR. RODERICK: Well, as I said earlier, it is not done on a component specific basis. It is done for the whole region in the vessel. So a scaling factor of 12-1/2 percent increase may have come from a different component in that Region A of the vessel, and is conservatively being applied to the flange to evaluate those.

CHAIRMAN WALLIS: Well, it still doesn't explain why the numbers come up by 12-1/2 percent when the pressure has hardly changed at all. There is still some mystery, which maybe you can clear up with the staff or something.

MR. PARK: Let me try something now. Instead of doing a full-blown code stress analysis for a power uprate, GE took the conservative approach to make sure that all these regions in the vessel would still meet the code allowable.

CHAIRMAN WALLIS: That's okay. So if you simply look at the EPU versus code allowable, that is what you are saying.

MR. PARK: Right.

CHAIRMAN WALLIS: But the problem that I have is that when I look at the difference between current and EPU, which should tell me by how much are you changing things, then that 12-1/2 percent is not something that I should take seriously?

MR. PARK: And you brought up the point that the pressure is not changing, and so why do we see a change there, and all it is there is a conservative --

CHAIRMAN WALLIS: It is a different method of calculation.

MR. PARK: It is just a conservative number being added to see if we still meet code allowable, as opposed to doing the number crunching on a full-blown code stress for the component.

CHAIRMAN WALLIS: So the comparison between current and EPU is different because different methods are being used. They weren't so conservative before? Is that what I am gathering?

MR. PARK: Well, I am sure that the original design was very conservative.

MR. MCGEE: This method was adequate to demonstrate the margin --

CHAIRMAN WALLIS: You are getting close in terms of the 80,000 and the 77,364. Presumably the staff asked this question for some reason, and this was supposed to answer some question was it? The question was whether or not the stresses were code allowable was it?

MR. PARK: It is just to demonstrate that we are still meeting code allowable designs.

MR. MCGEE: We did have discussions with the staff and with the particular reviewer on the method that was utilized.

CHAIRMAN WALLIS: Well, maybe when you come to the full committee that you can have a better explanation of why the numbers differ by so much from current to EPU, because it still seems to me that we are just saying that if somebody used a different method -- if you use a different method, then why show the comparison, and it is a little foggy what the comparison is really showing us.

MR. RODERICK: The request from the staff was what did we use to access the acceptability of stresses in these components, and in the work that had been done was a conservative scaling up of the current calculated stresses based on a maximum scaling factor in the region, and probably in this case came from a different component.

And then compared to the allowable or the acceptance criteria. So this was the basis for demonstrating margin and acceptability at EPU conditions for these components. And the two pieces that I was able to look at for the closure flange itself is in the original analysis, and the original drawings for the pressure term was using a thousand PSIG.

And in doing consideration of this area of the vessel, we are now looking at a 1,025. So just looking at that ratio itself would be at 2-1/2 percent increase. So that obviously is not it.

The temperature change is 3 degrees, and that is just based on a saturation temperature. So with those two pieces of information, I am very comfortable that this 12-1/2 percent scaling factor is from another component that is still part of this region of the vessel.

CHAIRMAN WALLIS: Well, I don't want to pursue it anymore. I think when you come back, if you could identify what that component is, and give us a clearer explanation of why the numbers are so different, and the full committee will be satisfied.

DR. POWERS: I don't know whether you are the correct speaker or not, but who should I ask about the fatigue usage factors?

MR. PARK: Fatigue usage factors?

DR. POWERS: Right.

MR. PARK: Do you have a question?

DR. POWERS: Well, in looking at your SAR, I noticed that your fatigue usage factors usually went down, and it was kind of surprising. And when I read the text, it said that they had used a less conservative method of analysis when they calculated the fatigue usage factor.

And in some cases they produced some remarkable reductions in the usage factors. For instance, the hydraulic system return nozzle went from about .85 down to .57. There is another case where it went from .97 to .2.

And I just wondered what the less

conservative analysis method was. I mean, what was entailed. But then I went on and I noticed that your feed water nozzles were -- that the usage factors actually went up pretty dramatically.

They went from about .85 -- and this is end of license times, and so .85 up to .968, and it doesn't surprise me that the usage factor would go up on the feed water nozzles.

But it seems like a big jump, even if you were using a less conservative analysis method.

MR. PARK: So you want us to just address what that analysis was?

DR. POWERS: I just would like to know what the differences were in the method of analysis.

MR. PARK: I was not prepared to do that, but we certainly can write something up. Do you want us to bring that back before the full committee?

DR. POWERS: You can just tell me one way or the other, formally or informally.

MR. PARK: Okay. As far as my conclusions, I think we have pretty much addressed those during our discussion. We follow the recommendations of the VIP, which I think is an industry standard that is going to be developed, and I believe that the VIP has also come out with a recommendation for going out and doing self-assessments to make sure that we are implementing those products.

We used Noble Chem and HWC, which has been shown to be an effective mitigation, and that those effects are going to help in the power uprate. And then also our vessel internals have been evaluated, and it is important to note that they still meet the design criteria with some margin.

CHAIRMAN WALLIS: Now, how did you decide what is sufficient margin? They meet the criteria, but --

MR. PARK: Right.

CHAIRMAN WALLIS: And you start getting into one margin that is sufficient, and that gets again fuzzy doesn't it?

MR. PARK: Well, they meet the criteria. They are still under what the design margins are, or the design is.

CHAIRMAN WALLIS: But you were very uncertain about your predictions. You presumed that they have a bigger margin.

MR. PARK: Excuse me?

CHAIRMAN WALLIS: If you meet the criteria, but you are close, and then you say that we are uncertain in our predictions, and we had better back off, then that would be increasing the margin because of uncertainty wouldn't it?

MR. PARK: Well, there was some conservatism in developing that criteria, and in developing what it was.

CHAIRMAN WALLIS: So, criteria with conservatism.

MR. PARK: Well, yes, that might be a better way to put it, yes. Is there any other questions? Thank you.

MR. BROWNING: Quickly. Dr. Powers, we have the calculation for the hydraulic system return line, but it is proprietary material. We can show it to you over the break if you would like to see it.

DR. POWERS: That would be fine.

MR. BROWNING: Great.

MR. HUEBSCH: My name is Steve Huebsch and I with the Duane Arnold Energy Center, and I am going to present some information pertaining to the containment pressure temperature response from the EPU.

Specifically the areas of interest that were looked as parameters as part of the analysis were the drywall pressures, the drywall gas temperatures, the drywall shell metal temperatures, the wet well pressures, the suppression pool water temperatures, and the containment loads.

These parameters were looked at both in the short term and in the long term. The analysis looked for both peaks, as well as the specific results and comparison between the two.

DR. SCHROCK: This containment, it is BWR4, is the toros containment?

MR. HUEBSCH: Yes, it is. It is the Mark-1.

DR. SCHROCK: Thank you.

MR. HUEBSCH: One thing that I want to address and that is probably the most important thing as far as evaluating the containment structures is when you look at the analysis and the way the analysis is done for both the peak drywall pressures and the temperatures, as well as the Mark-1 containment analysis for the load stuff, they start basically with a thermal hydraulic analysis to develop the loads based on the Mark-1 program, and testing that was done in accordance with those days.

Once those loads are developed, those loads are put into the structural calculations, and those structural calculations then are required to meet the ASME code requirements for a containment vessel.

And in all of the cases that we looked at, we were able to maintain the ASME code allowables as defined by the original design requirements. The methodologies that were used for the analysis

CHAIRMAN WALLIS: Are you going to talk about this 5 percent hydrogen limit? Is that part of your discussion or somebody else's?

DR. POWERS: I don't know what limit you are talking about?

CHAIRMAN WALLIS: Well, I was trying to understand the SAR, the draft SAR, and there is a lot of stuff about combustible gas control and 5 percent hydrogen, and it seems to be pretty obscure.

MR. HUEBSCH: That is not directly associated with this presentation, but we can discuss it. I guess

DR. KRESS: That is a corrosion production of hydrogen at 5 percent. It generally is not important generally.

CHAIRMAN WALLIS: It is not important?

MR. HUEBSCH: It is dealing with post-accident flammability issues with hydrogen-oxygen generation, post-LOCA.

DR. KRESS: Their past system was supposed to be designed to deal with that kind of levels.

CHAIRMAN WALLIS: That's right, and monitoring --

DR. KRESS: Yes.

MR. HUEBSCH: Monitoring, and then dealing with it such that we don't end up with a flammability situation post-accident.

CHAIRMAN WALLIS: Well, maybe we can just ask the staff to explain that one then if you don't want to.

DR. POWERS: We will meet with the staff tomorrow on that. You are not responsible for the SAR.

MR. MCGEE: We can discuss that, but --

DR. POWERS: Well, we can have the staff do that tomorrow.

MR. MCGEE: Well, I would be more than happy and if you want to wait until this is done, then I can answer any direct questions.

MR. HUEBSCH: The analysis methods that were used to do the containment analysis, in the short term cases, to come up with the peak drywall pressures, and to determine a short term temperature in both gas, as well as suppressible temperatures, was the M3CPT model that GE has.

This is the model that was used in the Mark-1 containment analysis. It was approved for use at that point for the short term analyses. In the long term event, which is looking at heat up based on decay heat changes and things of that nature after 8 hours, 10 hours, out.

CHAIRMAN WALLIS: Why would you expect a difference with the power uprate? Is it because of the heat stored in the metal and the fuel?

MR. HUEBSCH: For which case, the short term?

CHAIRMAN WALLIS: Is it a difference heat source; is that what it is? Why is there a difference in the power uprate?

MR. HUEBSCH: In the short term, you see certain things, and in the case of the Duane Arnold, we see a little more sub-cooling. So when you have the break, you have more mass transferred to the containment structure.

You see some changes in the pressure and in the longer term, you have a higher decay heat, and you transfer that heat. So you will see some changes in this analysis, and the changes were in accordance with what was expected because of those specific attributes to the power uprate.

The long term model that was used in accordance with the ELTR is called SHEX, and that was done to do not only the DBA-LOCA cases, but the other longer term analysis -- station blackout, the MPSH analysis for ECCS, and other methods.

And the SHEX model has been approved only a case by case basis. It i not generically approved like the M3CPT model was, but it is in accordance with the ELTR.

The loads, the specific loads on the containment structure, the Mark-1 containment loads were done in accordance with the Mark-1 program. The new loads as developed by, or as looked at, were compared back to the original test data, and the original program to determine whether or not it was previously bounded by the cases that were analyzed for the initial program.

The methodologies used were bounding correlations, and the models are conservative by nature, and they are benchmarked back to the original analyses, and they are qualified against the test data that was done for the Mark-1 stuff.

One specific issue that is important is the increase in the containment peak pressure, and this inputs into our local leak rate testing and various other things that we do to maintain containment integrity.

DR. SCHROCK: This is on a scaled test data and is the range of the parameters that are changed by the power uprate, and is that covered by that testing range that exists?

MR. HUEBSCH: Yes. The way the original testing was set up, it was based on things like pool swell and various things, and loads from the SRVs, and the blow down model through the vents.

These were analyzed numbers, and then they were -- and then the specifics of Duane Arnold were compared to those values that were tested in the low definition report developed by GE, and then other analysis.

And, Dan, I don't know if you wanted to add anything to that or not.

MR. PAPPONE: This is Dan Pappone with GE. There are two basic test approaches. One was a generic bounding test configuration that was developed to bound all Mark-1 containments.

So they ran the one test for all containments, and what we are doing in the individual plant applications is that we are comparing either the original analysis or in this case the power uprate analysis, to confirm that we are still within that original test basis.

There are some tests that are done on m more of a plant unique basis, where the test facility itself may be -- you know, the geometry there is fairly fixed, but some of the parameters, the initial parameters, were set up to bound a specific plant.

And there again we are looking at the power uprate conditions to confirm that we are still within or bounded by the actual test.

DR. SCHROCK: And I guess that was the way that I was thinking of it. Ordinarily, you would want your tests to cover the range of parameters to which it is going to be applied.

And here you are extending that range of parameters in a power uprate program.

MR. PAPPONE: Right, but we are going back and confirming that once we have extended the plant specific values to the power uprate conditions, we are still within the original bounds of the test, those parameters.

DR. SCHROCK: Okay. Thank you.

MR. HUEBSCH: In this case, it shows that basically the peak containment pressure analyzed has gone up 3 pounds.

DR. KRESS: Do you have to do that also for ATWS events?

MR. PAPPONE: Did we run these cases for the ATWS events?

DR. KRESS: Yes.

MR. PAPPONE: There was a pressure temperature analysis that was done.

DR. KRESS: Was it less than this?

MR. PAPPONE: Yes. The 45.7 psi occurs very quickly in the DBA LOCA event, and it is the peak pressure that is identified as analyzed per the whole series of accidents.

DR. KRESS: For the whole series of accidents. Okay.

MR. HUEBSCH: One of the issues that the long term SHEX model gets involved in is the use of containment pressure for an ECCS pump performance. At the Duane Arnold Energy Center, the plant was originally licensed with the use of containment overpressure for the core base systems specifically.

And in the original RHR core spray pump specifications, and in the containment specifications, there is actually criteria for how to analyze for the containment pressure models.

We have stayed within the original license bases, and the design bases for the containment analysis that we did today as part of the EPU.

The specific analysis, because when we got involved with the ECCS strainer issues, there were some aspects of the PRA that looked at what happens if you lose your injection capability, as well as lose your containment.

So those aspects have been looked at for insights, as far as the use of containment pressure, and what would happen if you lost it. The other thing is that when we ran the containment overpressure analysis that we were consistent with both the branch technical position that was written for this is how you should analyze to mitigate -- to minimize your pressure and maximize your pool temperatures.

As well as the original specifications for the plant. So we applied those aspects when we ran the cases, and the analysis also includes things like containment leakage, and it factors those in so that you are decaying off your containment pressure as the event goes on.

What you see here is the results of the analysis and where after the MPSH calculations were calculated what are the reliance on containment pressure is.

And there were two specific issues or points that were significant. One was at the 10 minute mark, because prior to 10 minutes the pumps were at run out conditions.

And at the 10 minute mark the operators restrict the pumps to rated conditions. Although there is pressure available in accordance with the analysis, we have no reliance on containment pressure in the first 10 minutes of the event.

But what we have found at Duane Arnold is that the reliance on pressure -- and this is in accordance with the original license -- occurs at peak pool temperatures.

And the black is the available, and the others required for original license, we require 3.1 psi for over pressure. And we will be looking at 5.3 psi and EPU conditions --

CHAIRMAN WALLIS: That's because the water is hotter in the pool?

MR. HUEBSCH: Correct. The water temperature has gone up, and I believe where we were analyzed after completion of the ECCS strainer installations was roughly 202 or 203 degrees fahrenheit peak pool temperatures, and we are looking at 209.2 degrees now.

And so a seven degree increase because of EPU for this specific analysis. One thing at Duane Arnold specifically is that the pressure is used for core spray, and you run into a temperature issue.

Core spray requires over pressure roughly at 180 degrees. So anytime the pool temperature reaches 180 degrees or above there is some reliance on over pressure with the current analyses assumptions, which are very conservative.

For the RHR system, the way we are configured is that after the events of the LOCA and divisional failure, you are down to one RHR pump. We don't require containment over pressure for that one RHR pump.

If you had two RHR pumps running, there is a requirement, but that's not our design basis, but we have analyzed all those cases. In the continual load section, Dan talked about that a little bit.

The specific loads that were evaluated for EPU were in line with the original Mark-1 pool swell, vent thrust, condensation oscillation, considerations of chugging, and SRV discharge, both the first pop, as well as the second pop, and the impacts of low, low set.

And whether there were any changes between our current configuration and EPU. The only one of these that had any impacts on the original loads that were analyzed were the vent thrust section, because we are seeing a higher dry wall pressurization rate.

And so you have a larger load on the vent system as the blow down model comes through the vents. The loads were increased roughly by five percent. It was a scaling or a linear evaluation rather than a detailed evaluation as was done in the Mark-1.

CHAIRMAN WALLIS: This is just a momentum of the fluid coming out of the pipe; is that what it is?

MR. HUEBSCH: I believe so. Dan, is that correct?

MR. PAPPONE: This is Dan Pappone. The basic vent thrust loads are from the momentum of the flow through there, with the power uprate looking at a little bit higher -- well, it is a trade off between a little higher initial break flow due to the subcooling, and a little bit lower energy coming out of the flow.

So every pound coming out is a little bit lower because of the higher subcooling, but we are getting -- the flow is coming out a little faster.

The next effect of that is a little higher pressurization rate in the dry well, and that shows up in the flow through the vents and the thrust loads.

And we run that through the Mark-1 calculational methods to come up with that 5 percent increase in the load definition.

MR. HUEBSCH: And those values were then compared to the structural allowables, and we are still within the allowables for the program. So it still meets the requirements of the ASME code, and all the margins are maintained.

Let's go to the conclusions then. One other area where one of the limits were challenged is in the station blackout event, at about roughly 3.7 hours into it the temperatures exceed the 281 degree containment design temperature.

And what was done in that case was the pressure and temperature requirements were looked at in comparison to the design requirements. Our containment design is 56 pounds at 281 degrees fahrenheit.

In the case of the station blackout event, it reached 283 -- well, just short of 284 degrees at the four hour point basically, 3.7 hours out, with 8.7 psi.

So because you are at such a low pressure and the temperature is only there for a short period of time before the four hour coping period is over, it was analyzed as being acceptable.

As we said earlier, the vent thrust loads, and the dry wall temperature as I just said, and the station blackout, were the only two events that challenged the thermal hydraulic analysis that had previously been done for the plant. So everything else was bounded.

And the structural analysis of all the events, including those two, after the loads were changed or evaluated for the higher considerations, were still within ASME code. So there were no challenges to the DAEC containment.

MR. KNECHT: I am Don Knecht from GE, and I am here to talk about the separators and dryers, and really a specific aspect of it. As you see here on the outline, the basic things that we are going to be focusing here on are the loads, and the separators, and the dryers, and some of the dryer experience that we have been having.

There was an RAI asked by the NRC dealing with the flow induced vibrations, and that's really the emphasis here. There are some other aspects, but

I am not going to address those now.

First off, a little bit on the impact of EPU. Obviously there is a steam flow increase, and both the steam flow increase coming out of the core affects the separators and turns the excitation forces which are transmitted to the shroud.

The dryer sees the increase flow pretty with regards to the power increase, and along with this is an increased pressure drop across the dryer. The other issues that I am not going to deal with here are the moisture content issues and the effect of the carry under change that goes on with the dryer performance, to just to try to contain the discussion a little bit.

Now, on the separator, the excitation forces that are going on are primarily from the flow increase, and also the swirling action in the separator as it is going out.

Those are increased, but Duane Arnold, not coincidentally, but Duane Arnold was the prototype unit for the BWR4 in terms of the stresses on the separator, and were instrumented at the time of start up.

And they found that the stresses at that time were only about 15 percent of the allowables.

With the EPU scaling it up for the increased flow and what not, it shouldn't be more than about 20 percent of allowables.

So as far as the separator is concerned, there really is no concern, and there is quite a bit of margin preserved for that. So I don't really see any issues with the separators themselves.

Now, on the dryers, the dryers are designed -- first off, they are a non-safety related component. It's main function is to keep the moisture content of the steam below a certain goal.

From a safety standpoint, we don't want any failure that a dryer such that there would be a lose part that could go and impact, let's say, an MSID closure or some other consequence.

So the dryer is designed for the main steam line break event and it has sufficient margin as it was originally designed to show that a main steam line break would not result in any adverse consequence.

Now, with the EPU, that event does not change because we are at constant pressure, and the main steam line break is a choke flow type of consequence. So there really is no impact on the loads on the dryer due to that.

So the structural integrity of it should be maintained. Now, the question in the RAI dealt with flow induced vibration, and because it is a non-safety component, it is not something that is analyzed with codes and what not.

Instead, it is more of a qualitative evaluation that is done, and because of the flow increases the load should increase by about 31 percent was the estimate.

CHAIRMAN WALLIS: This is based on a --

MR. KNECHT: Yes.

CHAIRMAN WALLIS: Now, is that really the whole story? I mean, don't you get vibration due to resonances and things which are not just proportional to momentum?

MR. KNECHT: This is really dealing with the amplitude of the flow induced vibrations. The frequency stays the same, because they are based on the natural frequency.

CHAIRMAN WALLIS: Unless you have some sort of resonance between some wall shedding or something and the mechanical behavior. You are way away from that and maybe you are right.

MR. KNECHT: That is not the concern. What we have done traditionally on the dryer performance, or not so much the performance, but the flow induced vibrations, is that we have looked at this on a fleet wide basis.

As it turns out, Duane Arnold has not had any particular problems with their dryers, in terms of this, but there have been cracks that have gone on in the dryer drains and some other components.

And so it has been looked at for several years, and we have a database going back into the mid-1980s tracking various dryer cracks that have been found.

So those have been used in a way that tries to identify areas that we think should be looked at. The VIP program talks about since the dryer is going to be removed during outages anyway that a visual inspection should be done on the dryers, and that is what has been done in pretty much all plants, but at Duane Arnold at any rate.

We use the fleet experience to try to guide those inspections as to what ought to be inspected, but the cracks that have been seen have been pretty odd, and they have not been so much of a problem.

So the areas where we have seen some of the more dramatic cracks have been in the drain channels, where we have seen some fairly significant cracks. But none of these cracks have led to any concern with the integrity of the components.

And so we use this program as sort of an operational way of evaluating the integrity of the components.

The other main point here is -- and getting on to the next slide, is that once these cracks are identified, they are readily repairable because the dryer is available in the pool, and they are generally repaired, unless they are so small that another cycle or so would not lead to any real concern.

The experience that we have had so far is that there have been two types of cracking. The IGSCC cracking has been a little bit more than half the cracks that have been observed. But those are not really impacted by EPU.

The chemical environment in the steam has not really been changed by EPU, per se. It is mostly just a steam environment. So we don't see any impact of EPU on IGSCC.

Now, the high cycle fatigue is the other area, and clearly there is an impact there. But again we have seen no cracking at Duane Arnold, and many plants have seen cracking, and they have been all repaired.

MR. ROSEN: Do you have a visual of this dryer where you can show us where the cracking has been observed?

MR. KNECHT: Over there I do.

(Brief Pause.)

MR. KNECHT: This is the general area. This is a brief diagram here of the dryer, and this is the top of the separators here coming up, and there is just a little bit of a gap here between the top of the separators, and these are the typical dryer drains where the steam will come up through these channels here, and through the dryer assembly, and then out.

Now, the moisture that comes off of the dryer collects down here in these troth areas here, and that leads into -- well, these are the bottom drains that lead into a troth, and then these are the drains that go down here and into the separator area, and combine with the separated moisture that is removed and then back.

But what doesn't really show on this diagram is that the cracks that have been seen are in some of the drain channels that lead from here out and down.

And subject to the vibrations that get generated here in the dryer drains, and so it is transmitted back down through that structure.

MR. ROSEN: You called them channels. But are they open at the top or are they pipes that are closed?

MR. KNECHT: The troth is open down in this general area, and then those troths drain into some pipes.

CHAIRMAN WALLIS: Well, the things that shake are the louvers aren't they? Whatever they are, the things that have the initial impact on --

MR. KNECHT: The drains here?

CHAIRMAN WALLIS: Yes. And those are the things that shake?

MR. KNECHT: Yes.

MR. ROSEN: So I am still trying to figure out what cracks.

MR. KNECHT: The drain channels -- and unfortunately they don't show this, but if you go in 3-dimensionally, there is some --

CHAIRMAN WALLIS: Well, it is a funny place to crack if the drains are shaking.

MR. KNECHT: That is the forcing drain.

CHAIRMAN WALLIS: It is transmitted down?

DR. FORD: Are those welded to conform down there?

MR. KNECHT: There are some welds, yes.

DR. FORD: And the cracking, presumably the stress is associated with those probably?

MR. KNECHT: It could be contributing.

CHAIRMAN WALLIS: And so because the pipe is further, it is the rigidity of the whole structure? The pipe is helping to retain --

MR. KNECHT: There are probably some stresses there. Because they are easily repaired, I don't think we go into a lot of analysis as to --

MR. ROSEN: Well, you are worrying about the wrong end of the problem. I mean, I grant that they are easy to repair, but what I am concerned about is one of those parts carrying away during operation, and what would happen then.

But I can't get a good feel for what would carry away since I don't have a picture of it. Can you help me with that question? What if the crack proceeded to where it severed the component?

CHAIRMAN WALLIS: It would just leak wouldn't it? I mean, it's whole --

MR. ROSEN: I don't care about leakage.

MR. KNECHT: If a part is completely

carried away -- well, first off, we have never seen an experience where we saw that it was completely covered away.

If it did, it would become some kind of a lost part, but I don't think it would go -- this is down below the dryer assembly, and it would probably find its way into this area someplace.

Now, there would be an increase in moisture coming out of the dryer, because you would be bypassing things and we are not concerned about that. So it has not really been a concern.

MR. ROSEN: Where would a plate of steel or an elbow of pipe that came lose there go? Where could it go?

MR. KNECHT: I suppose that it could find its way up here, and block part of the drain here.

MR. ROSEN: There is no way that it could get down below the separators?

MR. KNECHT: No, because steam is going up.

MR. ROSEN: Yes, but not all the time. When you shut down --

MR. KNECHT: It could go back through.

MR. ROSEN: Go with me for a minute on this. You have got a crack, and the crack proceeds to where the part fails. It is a piece of steel now, regular shaped.

Now for some reason in their wisdom, the operators decide to shut the plant down, and now there is very little steam. Where does the part go? You said don't worry about it, there is lots of steam. Well, not all the time.

MR. KNECHT: Wouldn't it just lay down on top of --

CHAIRMAN WALLIS: The pipe is held at the other end if it cracks off at the place you indicated, and it is just held at the other end, and the forcing function has gone away because it is broken off.

MR. KNECHT: Well, it might come down between the separators.

CHAIRMAN WALLIS: What if it doesn't come down at all?

MR. ROSEN: Well, it has broken loose.

CHAIRMAN WALLIS: No, it is only broken on one end.

MR. KNECHT: Well, it would wind up somewhere in that region, and probably lay on top of the separators.

DR. KRESS: I don't think I would put this one in my PRA.

DR. FORD: I think the argument is going to as far as that particular mode of degradation is concerned, it is not going to change.

MR. ROSEN: It is not an EPU specific problem. All I am trying to get someone to say is that it won't get down and damage the fuel, and hit the fuel or the controller out drive, or something like that.

Can you say that, that it can't get below the separators and get down to the fuel? Can you say that?

DR. KRESS: If you have ever seen those separators, it would have to be a mighty small piece to get down there.

MR. KOTTENSTETTE: How big a part are you saying has broken off? Is it something that size or a piece of something this long?

DR. SCHROCK: Well, your experience with the crack should tell you something about what a potential piece may be, and what it's size and origin might be.

MR. MCGEE: But if it resulted in a piece being broken off on one end and taking away the stress.

MR. ROSEN: You have a lot of experience

with cracking of these things to know that they don't result in pieces, but I don't have that similar experience. And cracking can be a funny thing, and you could end up with a crack that proceeds in a way that a piece comes loose in my world.

Now, I am only asking whether that piece could go down and cause some real damage in the fuel or in the control rod drives.

DR. KRESS: It is about the size of a quarter. It wouldn't hurt the control rod drive.

MR. PAPPONE: This is Dan Pappone. The region that we are talking about is outside of the shroud, and the fuel in the control rods are inside the shrouds. So we have got an area there --

DR. KRESS: Yes, it would never bother the control rods.

MR. KNECHT: If it went outside the shroud region, it would drop to the bottom, and where the recirc pump suction is. So unless it is just the right size part, and just with the right dimensions and weight, and all these improbabilities, it is not going to cause any problem.

I mean, the one thing about the drain channel cracks is that those have been several inches long. They are not little flakes of something.

So if something were to break loose, and it is hard to imagine that when all that stress is relieved, it is going to be a large part. There has been no evidence that any part has ever come loose.

CHAIRMAN WALLIS: And all of this is because of the drains are shaking up above?

MR. KNECHT: Well, that and probably --

DR. KRESS: It is probably residual stresses like he said.

CHAIRMAN WALLIS: Well, the velocity through the drains is pretty low isn't it?

MR. KNECHT: I'm sorry?

CHAIRMAN WALLIS: Gravity drain or something?

DR. KRESS: Oh, yes. There is hardly any velocity at all.

CHAIRMAN WALLIS: And so there is nothing there that is going to happen. It is the drains that are shaking.

MR. KNECHT: And that is creating the high cycle --

CHAIRMAN WALLIS: And are these drains being tested? Have they been tested at higher velocities in a testing facility? Is there a separate effects test? You take each separator and test it?

MR. KNECHT: Not so much from a flow induced vibration standpoint, but from a performance standpoint, we have done extensive testing on the dryers and separators.

CHAIRMAN WALLIS: So if there were any kind of residences or anything --

MR. KNECHT: Well, we are well within the range of experience.

CHAIRMAN WALLIS: And you have run them in a separate effects test at these flow rates?

MR. KNECHT: Yes, with the uprated flow rates, we have data that supports that.

CHAIRMAN WALLIS: Yes, you have.

MR. KNECHT: Now, I guess one other point to make here is that we have had at least three plants that have operated at an extended power uprate for several years now, and at least two of them.

And we have had some KKM that have operated up to not quite the 120 level, but they have been operating much higher than their original design. And they have shown virtually no evidence that there is increased cracking because of the uprate.

DR. KRESS: Is their power level comparable to --

MR. KNECHT: It is slightly higher than

Duane Arnold. Duane Arnold is one of the smaller units.

CHAIRMAN WALLIS: And do they use the same kind of separators?

MR. KNECHT: No. Hatch and KKM are very similar, and KKL is slightly different. And by way of conclusion, and I think we have gone through most of this already --

CHAIRMAN WALLIS: The percentage figures that you are giving there on the Hatch, and KKL, and KKM, what are those again?

MR. KNECHT: Those are power updates above the original power level.

CHAIRMAN WALLIS: So they are the new power updates compared to the old power?

MR. KNECHT: The current uprating power versus the original power.

DR. SCHROCK: I guess you said these three are not the same as each other, but it wasn't clear that you meant the comparison to Duane Arnold.

MR. KNECHT: Well, Hatch and KKM are both BWR4 units, and have pretty much the same dryer.

DR. SCHROCK: The same dryer? Okay.

MR. KNECHT: KKLs and BWR6s have slightly different dryers.

DR. SCHROCK: I thought because they were foreign that they might have a difference other than that.

MR. KNECHT: No, other foreign plants have different dryers, but these are similar to Duane Arnold. Again, the dryer really has an operational function, and for testing it and repairing the cracks, and that sort of thing, is really an investment protection issue.

There is no loss of margin with the structural integrity basis of the dryer, because the main steam line break does not change. And we think we know where to look for flow induced vibration cracks based on the experience.

Again, Duane Arnold has not seen any, but we know pretty much where to look. They are visually inspected at every outage, and so there is kind of a confirmation there that can be managed. And they are also repairable.

So we don't see a safety concern with these dryers, and the integrity of them and the performance of them is managed by the utilities.

CHAIRMAN WALLIS: And the visual inspection, this is with some sort of video device?

MR. KNECHT: It can be. Once it is in the dryer pool, there is usually a camera that is used to inspect them. But there is no hard requirement on how that is done. I think that is up to the utilities. Any more questions?

DR. POWERS: I noticed in your SAR that you discuss increases in the vibration levels for your recirc drives, and that you looked at those by extrapolating some results from start up testing. Can you explain more about that to get to the kinds of recirc close that you are going to have at the power uprate for that test data that are applicable?

MR. KNECHT: Well, the flow rate in the recirc system increases just slightly to overcome the pressure drop.

DR. POWERS: I see.

MR. KNECHT: It is not a very large increase.

DR. POWERS: Okay. I was thinking it was proportional.

MR. KNECHT: It is about a one percent change.

DR. POWERS: That explains it.

MR. BROWNING: This is Tony Browning again from Duane Arnold, and the next presentation that I am going to co-give with Dan Pappone from GE is on the

ECCS analysis that was done for the extended power uprate.

Dan is going to get up and talk about the methodology side of how the analysis was performed, and then I will get up and talk about the plant specific results, and the conclusions.

Again, we are trying to demonstrate that we have got adequate operational and safety margins from the LOCA perspective at the extended power uprate conditions.

MR. PAPPONE: Okay. The methodology that we are using is the SAFER/GESTR methodology, and it is kind of an intermediate methodology, where we are taking advantage of the technology development, and basing the primary analysis on realistic, a fairly realistic basis, using nominal models and inputs.

But at the time that the methodology was approved, we still had to live within the original 50.46 in Appendix K requirements. So we do calculate a licensing basis PCT that uses the required Appendix K models, and that is the PCT that is used to compare against the 2200 degree acceptance criteria in 50.46.

We also, because we are doing a nominal realistic analysis, we also do an upper bound PCT calculation to demonstrate that this licensing basis

PCT that we calculate is sufficient --

DR. KRESS: What do you mean by upper bounds?

MR. PAPPONE: Well, we essentially work through to what we expect would be a true plant PCT given the modeling uncertainties, and the conservatisms that are in the SAFER code would account for those.

We account for the test uncertainties, and then there is a set of significant input parameters that would vary at a two sigma level to come up with an upper bound level, and so we are doing an uncertainty analysis.

DR. KRESS: So a two sigma level rather than an upper bound? It is a continuous distribution. You are picking out the two key parameters that determine it and see what you get.

MR. PAPPONE: Right.

CHAIRMAN WALLIS: How much does a two sigma above mean?

MR. PAPPONE: By the time that we factor in all of the uncertainties and the two sigma part, we are usually looking at something like 300 to 400 degrees above the normal temperature.

And then also we do have a restriction

that was placed on the methodology itself in the SAR that approved the methodology, and we have a restriction on that upper bound PCT. We are not allowed to let that go higher than 1600 degrees.

DR. KRESS: Well, that is actually built into your --

MR. PAPPONE: That was a condition on the SAR that approved the methodology.

DR. KRESS: How did they arrived at that limit?

MR. PAPPONE: Two pieces; one is the test data that was submitted at the time, the actual bundle heat up test data. Those tests only went up to 1600 degrees because they stopped the test at that point to protect the test bundle.

And the other part is that the upper bound PCT evaluations that are in the generic LTR, licensing topical report, were in the 1600 to 1700 degree range.

CHAIRMAN WALLIS: So you might argue that on the 600 degree margin to maybe 200?

MR. PAPPONE: Well, I don't want to push that. That is a nice thing to have, but we are also looking at relaxing this and bringing it before the staff.

DR. SCHROCK: I have a question concerning the decay heat evaluation in this method. My recollection of the SAFER/GESTR methodology was that you had used the 1979 ANS standard, with a lot of evaluations for different fuel conditions, different points in life and so forth.

But you say then that in the end that you were required to do an Appendix K evaluation, and so that would mean that you would have to use the decay power specification there, which was the older draft ANS standard, 1971-1973.

MR. PAPPONE: That's right.

DR. SCHROCK: In the SAR, it takes about the may-witt (phonetic) approach, and that is confusing to me. I mean, what I just described is either a best estimate approach, which is the '79 standard, or the conservative approach which is in Appendix K, which is the '73 standard, draft standard. So how does may-witt (phonetic) get into this at all?

MR. PAPPONE: May-witt is used in the containment LOCA analyses, and was originally used in the containment LOCA analysis. It was never used in the ECCS performance for the clad heat up.

DR. SCHROCK: Yes, you're right. That's where it is here. So you are using a different --

MR. PAPPONE: What we were using was --

well, the nominal calculation and the upper bound calculation is the '79 ANS 5.1 standard with that uncertainty.

And then the licensing calculation, that's where we pick up the '71-'73 ANS 5.1 standard.

DR. SCHROCK: And this May-witt is not in LOCA?

MR. PAPPONE: That is not in the ECCS LOCA.

DR. SCHROCK: In the ECCS considerations?

MR. PAPPONE: Right. That was in the containment LOCA.

DR. SCHROCK: And it is just a sort of fact of history that you -- that you had May-witt plugged in there, and nobody ever changed it. Do you think it is better for containment analysis?

How can one be better for LOCA and the other one be better for --

MR. PAPPONE: I don't know the basis for using May-witt in the original containment analysis, but the current power uprate containment analyses we were using in the '79 ANS 5.1 standard with the two sigma uncertainty on that.

CHAIRMAN WALLIS: And so May-witt has gone away completely?

MR. PAPPONE: May-witt has gone away completely. The only time that we would see that is if we are comparing back to the original calculations. Say if we are doing a benchmark calculation. I am not familiar with the statements in the SAR.

DR. SCHROCK: Well, the statement in the SAR is that the May-witt decay heat model used in the current licensing basis.

MR. PAPPONE: Now, is that in the containment section of the SAR?

DR. SCHROCK: Right.

MR. PAPPONE: Yes. Well, Steve or Tony may know. But I think that is a case where you redid the containment analysis a couple of years ago, that is when we would have moved off of May-witt.

MR. BROWNING: Right. Now, the FSA cases of record are the original containment evaluations that were done, and they were done with May-witt. So we were highlighting to the staff that we had undergone a change in methodology as we went through EPU.

CHAIRMAN WALLIS: Well, the staff accepts the new methodology.

MR. BROWNING: Correct.

CHAIRMAN WALLIS: Well, is there a problem with this?

MR. PAPPONE: Or is it just a historical notation in the SAR.

DR. SCHROCK: Well, I was trying to understand why there would be any use made of May-witt at this point in time.

CHAIRMAN WALLIS: Well, there isn't. It's gone.

MR. PAPPONE: It's gone.

CHAIRMAN WALLIS: And so we can forget it.

DR. SCHROCK: It says in the SAR that it is the current licensing basis.

MR. PAPPONE: And so continuing. It's Tony's turn.

MR. BROWNING: And on to the plant specific analysis and results. The analysis was done for the Duane Arnold specific ECCS configuration, and what was unique for BWR4 was the fact that we had LPCI logic, and so we have to look at that in a single failure evaluation space because we have a vulnerability there that some of the other designs don't have.

And which is the failure of the LPCI inject value to open, which completely starves the vessel for LPCI flow. So that factors into the single failure evaluation that is unique to us.

And then we do the full break spectrum evaluation to confirm that the design basis accident is the double-ended guillotine break of the suction line is the worst case, and that we validate that the large breaks do dominate over the small breaks. So we look at the small break spectrum as well.

And for the plant specific results, the licensing basis PCT that we talked about and that we do the conformance to 50.46, we came up with a calculation of a bounding value of 1510. So we have a great deal of margin with the regulatory limit.

CHAIRMAN WALLIS: LB means licensing basis?

MR. BROWNING: Yes, PCT, and then the upper-bound PCT.

CHAIRMAN WALLIS: So which is lower bound and upper bound, and its licensing phase is an upper bound?

MR. BROWNING: Yes. The jargon. So the upper-bound PCT is only 1350, which is well below the 1600 limit, and we also see that the upper bound is below the licensing basis. So we meet both requirements.

CHAIRMAN WALLIS: This is much like what

you have pre-EPU is it?

MR. PAPPONE: There was only about a 10 degree change in the licensing PCT DBA.

MR. BROWNING: Right. So as you see here, there is an across the break spectrum of break sizes, from the small break, all the way up to the DBA case.

You can see the change due to the EPUs, and the little squares are the pre-EPU cases, and then the triangles are the EPU cases. So you see the trend follows, and then when you get to the DBA case, they are very close. They are within 10 degrees of each other.

And then you can see where the upper bound at the DBA case shows up.

DR. POWERS: In fact, doesn't your EPU temperature, peak clad temperature, go down?

MR. BROWNING: Yes, slightly.

DR. POWERS: And that is because of the flattening out of the core --

MR. BROWNING: Yes, the same phenomena that we saw earlier. The peak bundle has a little more flow because we --

DR. POWERS: I looked at that, and I said to myself that this has got to be red. I have got to see this.

MR. BROWNING: I think you will see the words in the staff safety action are counter-intuitive.

CHAIRMAN WALLIS: The limit on the right hand, the three square feet -- what is the limit?

MR. BROWNING: It is 2-1/2 square feet, yes.

CHAIRMAN WALLIS: And which pipe is it?

MR. BROWNING: That is the recirc suction line. That is the largest pipe that we have on the vessel. So, you can see -- well, the trend stays the same, and the results go up a little bit.

MR. ROSEN: And the solid lines are done with the Appendix K models. I just noticed that in the cartoon that you showed before.

MR. BROWNING: Yes.

MR. ROSEN: And that shows that that number was about 2000 degrees.

MR. BROWNING: Oh, that was just a representative cartoon. Those were not the plant specific results. That was just to get across the jargon.

MR. PAPPONE: That was to show which limit went with -- or which temperature calculation went with what limit, and the relative relationships.

MR. BROWNING: Right.

MR. ROSEN: The one on the left looks okay relative to the numbers on the right.

MR. PAPPONE: Well, the one on the right is okay, too, because it is the one that is compared to the 2200.

MR. BROWNING: But it is not the Duane Arnold result.

MR. ROSEN: So it is not the number, your number?

MR. BROWNING: It is not our number, no. And as Dan has explained, the methodologies is where we try to build in the margin, especially using the upper bound technique that account for all the uncertainties, and the licensing basis PCT still has to apply the conservative Appendix K models for the regulatory conformance.

And then the acceptance criteria are conservative as well. So for the plant specific results, we saw obviously no impact on safety margin because we had a great deal of margin to 2200.

And then the operating margin is obviously maintained by that same operating condition.

DR. KRESS: What would you do if those numbers went all the way up to the 2200 on your

Appendix K?

MR. PAPPONE: On the licensing PCT?

DR. KRESS: Yes.

MR. PAPPONE: That's fine. We have got plans that are licensed near 2200, and we have --

DR. POWERS: And there is definitely one at 2183.

DR. KRESS: Yes, that's what I thought.

MR. PAPPONE: We do have a couple of the early plants that are PCT restricted after 2200.

DR. KRESS: Well, this is in terms of margin. If you are at 2200, you still have sufficient margin.

MR. ROSEN: This goes to the question of whose margin is it.

MR. BROWNING: The 2200 up to the field cladding failure point, that is the licensing margin and that is the sacred turf. What we are talking about down here is the margin to 2200 and this is the operating latitude. And as long as we maneuver within here --

MR. ROSEN: I would propose the standard that if you would license up to the 2200, then the margin is the licensee and the vendors. And the answer to the question is whose margin is it. It has been licensed up to nearly the 2200. So I think that is QED.

MR. BROWNING: Right. And now we are on to your favorite topic.

DR. POWERS: We are about to move on to a topic that I know will go quickly because PRA invokes a little interest in this committee. I wondered if the members wanted to take a 10 minute break in order to build up their strength to get through this.

DR. KRESS: No, let's go on.

DR. POWERS: Apparently they want to charge ahead. Any acquisitions that I am a slave driver will not be tolerated. Okay. So, Brad is going to come up here, and he looks like a brave, strong young man. He has taken a few slings and arrows in a checkered career here, huh?

MR. HOPKINS: My name is Brad Hopkins, and I am a PRA engineer at Duane Arnold. The purpose of the PRA evaluation for a power uprate was to identify possible vulnerabilities resulting from power updates.

These may come from potential sources, such as changes in system criteria possibly, or maybe from changes in human error probability. I would like to note at this time that a power uprate is not a risk informed application.

But nonetheless we are interested in the question of risk. That is, does power uprate constitute undo risk in some way or form.

DR. KRESS: How do you identify vulnerability?

MR. HOPKINS: Well, we will look at, or what do we use as a criteria for vulnerability, go to the next slide.

DR. KRESS: I didn't want to say that word because I get criticized every time I use it.

DR. POWERS: As well you should.

MR. HOPKINS: We will answer that question. My second bullet here is we have a guideline that tells us how much of an increase in core damage frequency or large/early release frequency constitutes a significant increase.

We used or we compared our results to the EPRI PRA applications guide. We also -- and I think the NRC has been using Reg Guide 1.174, and we compared to that also to make sure that we meet that.

Now, the areas that we looked at are equipment, reliability, and we look at initiating event frequencies, and we looked at system success criteria, such as how many pumps do we need to operate to have adequate core coverage, or how many SRVs do we need to open to adequately depressurize.

And finally we looked at human error probabilities. Now, we didn't have anything too interesting in the first three bullets.

DR. KRESS: How do you actually look at the effect of power updates on equipment reliability?

MR. HOPKINS: How do we look at the effects on equipment reliability?

DR. KRESS: Yes.

MR. HOPKINS: There is -- well, I guess there is not a hard and fast methodology that we could find if you take a good look at it, but we tried to assess what equipment might be seeing higher duty, such as the feed water pumps.

And we recognize that some equipment does have higher duty, and failure rates may be higher. But I think with the maintenance rule in effect now, we have good programs for monitoring the effectiveness of our safety related equipment. So we don't really anticipate --

DR. KRESS: So in your PRA, you just used the same failure rates for the equipment?

MR. HOPKINS: For this assessment, we wound up inserting the same failure rates for the equipment.

DR. KRESS: But you did review because you went back to see if you thought there was any reason to change those?

MR. HOPKINS: Yes.

MR. ROSEN: You are talking just about reliability, and are you also talking about unavailability as well?

MR. HOPKINS: Well, unavailability as well.

MR. ROSEN: The slide just says reliability.

MR. HOPKINS: We identified all basic events that had a raw value of a certain value, and we focused in on those pieces of equipment, the equipment that we felt was significant.

And we asked ourselves is there any reason that we should increase the failure rate of this equipment, and I think in all cases that we said no.

So I am going to focus later on in the presentation on focusing more on the human error probabilities, since those are the ones that have the most impact.

Here is a summary of our results, and I have a column for the base value, or our present PRA numbers, and a value for extended power uprate, and in the right-hand column --

CHAIRMAN WALLIS: The PRA predictions are valid to three significant --

DR. POWERS: At least. That's always.

MR. HOPKINS: We will take a quick look at the question of uncertainty on the last slide here. But, no, I don't have uncertainty drawn up here.

But the computer calculates it out, of course, to --

CHAIRMAN WALLIS: And you are arguing is the change is what you are looking at, and not something that you have a better handle on than the absolute value?

MR. HOPKINS: Right. Here it is the change that we are interested in.

DR. KRESS: If I look at your base case CDF and LERF, I get an early conditional failure probability of .05 and thereabouts just in my head. For Mark-1s, I am used to .5s and .4s for that. Do you guys have that good of a containment? It's a Mark-1 isn't it?

MR. HOPKINS: So you are comparing the level one to the level two?

DR. KRESS: Yes, as .05 is a pretty good number, and for Mark-1s, I am used to an order of a magnitude higher than that in PRAs.

MR. HOPKINS: Yes, and so the level two is lower than we might expect.

DR. KRESS: Yes.

MR. HOPKINS: I guess I don't have a real good answer for that.

DR. KRESS: I guess the question would be why is your particular plant looking so much better than other Mark-1s?

DR. POWERS: I will make a guess.

DR. KRESS: Okay.

DR. POWERS: A drywall spray.

DR. KRESS: They have a drywall spray.

DR. POWERS: They have it and they are using it.

DR. KRESS: That certainly could make a difference.

DR. POWERS: Because the reason that you get the high failures on the Mark-1s is either a melt flow across the floor without water, or an overheat at the seals up at the top. And the spray takes care of both of those.

DR. KRESS: That is probably a good explanation, Dana.

DR. POWERS: That's my guess.

MR. HOPKINS: That sounds very good to me. In the future, I think utilities are seeing some value in providing PRA results to the public, and making it publicly available. I think we will see that trend in the future.

And on the human error probabilities, we reviewed all human error probabilities with a raw value of 1.06 or greater, and then we employed a map, a thermal hydraulic code, to determine whether the --

MR. ROSEN: How did you select 1.06? It seems so timid.

MR. HOPKINS: Okay. Well, 1.06 --

MR. ROSEN: I would have thought that you would pick a number like two at least.

MR. HOPKINS: Well, 1.06 corresponds to an increase in core damage frequency of 1 times 10 to the minus 6. So any increase at this event, if an event would cause the core damage frequency to increase by 1 times 10 to the minus 6 or more, then we would evaluate it. And there were about 20 or so --

DR. POWERS: I can't help but point out to the members that this is what we have been asking the staff to do for the human performance program plan for a long time.

So these particular evaluations ought to be very interesting to us; and the question you ask is are these humans doing as well as we would like them to do here, and here you have a basis for looking at this.

DR. KRESS: Why do you call it a MAAP thermal-hydraulic code? I wouldn't have characterized it that way.

MR. HOPKINS: As opposed to a probablistic --

DR. KRESS: I would have characterized it as a severe accident code, but a relatively poor thermal hydraulic code.

DR. POWERS: That is not how you characterize it in private.

MR. HOPKINS: Well, we could call it a transport code. We will call it a transport code, a radio nuclide transport code.

CHAIRMAN WALLIS: He is calling it thermal hydraulic to try to give it respectability.

MR. HOPKINS: We recognize that it has limitations. Next slide, please.

DR. POWERS: But in fairness wouldn't it be pretty adequate for this?

DR. KRESS: Yes, I think that would be

perfectly adequate for this. For a BWR, it is actually pretty good for this sort of stuff.

DR. POWERS: And all it is worried about is heat and mass here.

DR. KRESS: Yes, this should do fine for that. I didn't mean to put it down.

DR. POWERS: What do you mean you didn't mean to put it down.

CHAIRMAN WALLIS: That is a good first approximation to thermal hydraulics. There is no energy. It is MAAP.

MR. HOPKINS: I think we maintain a questioning attitude when we use MAAP, and we try to compare it with more detailed codes when we can, or when that is possible.

Now, I would like to go through the five most important operator actions that we found, and it is not my point to dwell in great detail on each of these.

But more to give you a sense of what is causing the most increase in the core damage frequency. Most of the increase came from ATWS events. So four of these operator events apply to various ATWS scenarios.

So the first one is failure to initiate

standby liquid control. So this is applicable to ATWS events where the main condenser is not available. Therefore, all of the energy is going down into the suppression pool.

DR. KRESS: The spray is not available to them either? Is the suppression pool spray not available?

MR. HOPKINS: Well, in many cases, yes, I think the sprays are available.

DR. KRESS: Yes, there is too much heat going in there.

DR. POWERS: There is too much heat going into the containment.

MR. HOPKINS: Now, we look at two different time frames for injecting standby liquid control. If we are able to inject early, then later on in the event we only need one RHR service water train, and one RHR train to remove the decay heat from the water.

If we are not able to inject early, we still have an opportunity to inject standby liquid control a little bit later. But if we inject later, then we need to use both trains of RHR service water and RHR for adequate core cooling.

CHAIRMAN WALLIS: What is the formula that relates to that? Is there a magic correlation that says that when you go from 6 to 4 that --

DR. KRESS: It is an EPRI correlation.

CHAIRMAN WALLIS: All right. So that is based on experience?

MR. HOPKINS: It is an expert opinion is what it is.

CHAIRMAN WALLIS: Oh, so it is based on data.

MR. HOPKINS: We used a variety of methods. That is not my area of expertise. So I am not able to address it in really good detail.

MR. ROSEN: But fundamentally those techniques take into account the fact that operating under stress when you have less time, you have a higher likelihood of failure?

MR. HOPKINS: That's right. That's right. But in this case, like Steve was saying earlier, our operators are well practiced in injecting standby liquid control. We cover it often in the training.

MR. ROSEN: Would you go back to the prior slide for a minute. Now, you see, that is the point that I made earlier, that for early initiation, with the time reduced from 6 to 4 minutes, but the deterministic analysis assumes 2 minutes.

MR. HOPKINS: It seems like we are overly favorable on the deterministic analysis.

MR. ROSEN: Well, you are overly pessimistic here. But they are not the same, and I think I understand why. One is a best estimate, which is this one; and the other one is a conservative, or is an analysis for deterministic purposes.

MR. HOPKINS: Right.

MR. ROSEN: I wish they were the same somehow, but I am having trouble reconciling two different estimates.

MR. HOPKINS: I think we are looking at two different outcomes possibly.

MR. ROSEN: But we also know in this case -- and Steve -- I am having trouble with your last name.

MR. KOTTENSTETTE: Kottenstette.

MR. ROSEN: Kottenstette. He told us that the four minutes and the two minutes are both achievable times because everything the operator needs to do is in front of him in the control room; information and the mode switch and key.

So it is irrelevant whether it is four or two minutes. The point is that the operators can take those actions, and it is in their training program, and it is in the simulator.

It is a critical task, the training program, and they can take it in either case within the four or two minutes. All right. Go on.

MR. HOPKINS: All right. This one is failure to inhibit ADS. Now, for an ATWS, for most ATWS scenarios, we want to prevent automatic depressurization from occurring.

The reason for this is that if you depressurize, then the low pressure emergency core cooling systems initiate automatically, and they dump a lot of water into the vessel.

And we have a concern of a reactivity excursion when that happens. So we really need to inhibit ADS.

CHAIRMAN WALLIS: So your ECCS system is not borated?

MR. HOPKINS: That's correct.

MR. ROSEN: Well, it is starting to borate it, but very slowly.

MR. HOPKINS: Correct. So here the available time is reduced from 16 to 10 minutes, and we have a corresponding increase in the failure probability for that event.

And failure to reduce power via the

lowering of reactor vessel water level. Another means of getting our power level down is to lower the water level down to below the level of the feed water injection spargers.

By doing this we avoid the need to depressurize the vessel by keeping the suppression pool temperature below its heat capacity temperature limit. The available time is reduced from 15 minutes to 12 minutes, and we have a corresponding increase in the failure probability.

DR. KRESS: In your failure to initiate standby liquid control, you have 14 minutes for late initiation, the failure probability was about .09, and on this one you have got 10 minutes for the ADS, and it is .03 apparently.

How come the failure probability is lower for a 10 minute than it is for a 14 minute action? Has it got something to do with the type of complexity of the action or something?

MR. HOPKINS: Right. We would be factoring in the complexity of the action.

DR. KRESS: And that is built into the model somehow?

MR. HOPKINS: Yes. And here we are really combining two of the previous operator actions for a little different scenario here. This one is an ATWS, where the turbine bypass valves are available.

Now, the turbine bypass valves can pass about 24 percent of reactor power. However, the power is about 45 to 48 percent. Therefore, we still have a significant amount of energy going down into the torus water level.

In this scenario the operator is not able to get the power level down, either by lowering the water level, or by injecting standby liquid control.

So we increased the failure rates for both of these by the same amount as what we saw previously.

DR. KRESS: You uncover the core when you lower that water level?

MR. HOPKINS: Do we uncover the core? Yes, I believe the EOPs have us go down to minus -- about minus 30 inches.

MR. POST: This is Jason Post. That is the collapsed level. There is still a two phase level swell that is well above the top of the active fuel.

MR. HOPKINS: Thank you, Jason. The last one -- okay. Now we have looked at all of the ATWS events. This one is applicable -- this one is a failure to depressurize the reactor vessel, and it applies to transients, small LOCAs, and medium LOCA events.

So if your high pressure systems are not able to inject, it is very important for the operator to manually depressurize the vessel so that the low pressure systems can turn on. So this is a fairly significant operator action in our PRA.

So I guess for transients and small LOCAs the available time is reduced from 65 minutes to 55 minutes, and so these probabilities are pretty low compared to the other ones.

I hope that the operator recognizes that he is not -- that he doesn't have any water going in the vessel. I think it is something that is pretty easy to see, and the action is easy. He should be able to do it in an hour.

We looked at external events, and here we are looking at things like high winds, floods, tornadoes, transportation, chemical hazards, and we didn't see any effect of power uprate on those events.

However, for fire and seismic, those were the only external events in which we felt that there was a measurable effect. Now, for here, we carried the operator actions through our fault trees for fire and seismic PRA.

And we found less than a one percent

increase here, and so we didn't find anything too interesting in external events. No additional unique hazards were identified.

For shutdown risk, here power uprate is judged to have a negligible effect on our overall ability to adequately manage shutdown risk. And since about 1992, we have employed EPRI's Sentinel model for monitoring risk during refuel outages.

So here we look at both the defense and depth in meeting various safety functions, and we are calculating probability of boiling in the core region.

So we think that we have had a very good handle on shut down risk. We are experienced with it by this time, and we think that with a power uprate that experience will continue.

DR. POWERS: I guess I don't understand why when you think about it that if you have a power uprate of 20 percent that you must have roughly a 20 percent increase in decay heat load.

And so your time to boiling must be roughly 20 percent shorter than it was before. So the time that you have available to recover from some loss of cooling capacity must be about 20 percent shorter.

MR. HOPKINS: Yes.

DR. POWERS: So shouldn't that mean that

you have roughly a 20 percent increase in risk being shut down?

MR. HOPKINS: That's correct.

DR. POWERS: And a window of shutdown, and I don't mean all of it. But in a window of shutdown where boiling risk is reasonably high.

MR. HOPKINS: You are correct. The decay heat values are higher. And we track very carefully the number of systems that we have available for removing decay heat, and at any given time during the outage we would know exactly how many systems we have to have operating to meet that load.

But in general there is only a few periods of the outage where the times are very short. That would be the transition periods when you are cooling down the vessel, and when the water level in the vessel is at its normal level.

But for most of the outage the reactor cavity is flooded all the way to the top to allow for fuel moving. And therefore the times -- we have on the order of hours, and sometimes 24 hours for later periods in the outage for responding to events, whether it is loss of decay heat removal, or inadvertent drain down events.

DR. KRESS: Has your PRA been subjected to the industry peer review process?

MR. HOPKINS: Our PRA went through the industry certification process four years ago.

MR. ROSEN: It was one of the first, I think.

MR. HOPKINS: We were one of the first. We had a very favorable certification, and I think one of our real strengths is our documentation out there. We have a living PRA program that was developed within a qualitative framework.

MR. ROSEN: Now, I thought you were going to say in response to Dana's question is that you do get more decay heat as he points out, but that you end up not getting to shut down temperatures as quickly as you would now.

So that ultimately the way that you control shutdown risk is to basically wait a little longer before you could initiate shutdown operations.

MR. HOPKINS: Right.

MR. MCGEE: But it ends up being an operational impact where we need to keep the shutdown for a longer period of time before going into other phases of an outage.

DR. POWERS: It seems to me that becomes a time period that bean counters will attack, and the pressure to shorten that.

MR. HOPKINS: Well, there will be pressure to shorten that, but the bean counters are already in this case very happy, because they have been running at 20 percent.

DR. POWERS: They are only happy quarter by quarter, and the next quarter, they are going to want another 20 percent.

MR. ROSEN: But the plant staff should point out to them that while it is true that it is going to take a few more hours to get into shutdown operations, they should be thinking about all the money they have made while the plant ran at the extended power uprate.

MR. HOPKINS: Well, that vessel is still pretty hot when the mechanics are unbolting the head bolts. They will be doing a dance. Now, uncertainly. In our original IPE submittal, we addressed uncertainty with a sensitivity analysis. That is to say that we don't have a formal rigid uncertainty analysis for our PRA.

For the present study, we selected operator actions that were sensitive in the first place. That is, the first step of this study was to look at those parameters that are sensitive.

One other thing we did was we looked at all of the low worth operator actions, and we doubled their failure rates all at once. We ran a single case with all of those values doubled.

DR. KRESS: This South Texas guy here is going to ask you why you didn't increase those by a factor of 10. That's what they did for their effect of QA on the reliability of low worth components that are not safety significant.

MR. HOPKINS: But not for a power uprate. We would be talking about an exemption request.

DR. KRESS: Yes, you see, an exemption request.

DR. POWERS: As long as you are harassing the South Texas guy, I will harass him some more. Wait as long as you want to. The decay heat load that you have to deal with is still higher by 20 percent, and it still shortens down all the times that you have to boiling by 20 percent.

DR. KRESS: So that doubling didn't have any significant effect.

MR. HOPKINS: The doubling did not.

CHAIRMAN WALLIS: Are we back to the beginning?

MR. HOPKINS: We are not, and that is the last slide.

DR. POWERS: Are there other questions that people would like to ask about the PRA? Not seeing any and not looking very hard for any, Ron, did you have any closing comments that you needed to make?

MR. MCGEE: I just wanted to thank the committee today for allowing us this time to present, and by my count we have three things that we need to follow up on.

And they are Mr. Wallis' question concerning the stress analysis, and Mr. Powers' had a question and I believe we will be able to follow up with something on that.

But then also we have the post-LOCA H202 monitoring question that I think we will be able to address tomorrow during the staff's presentations. Other than that, are there any other questions for me at this time? If not, thank you.

DR. POWERS: If there are no further questions, I will turn the meeting back over to the Thermal Hydraulics Subcommittee Chairman.

CHAIRMAN WALLIS: Dr. Powers has done his usual and hasn't kept us late. So I am very happy to recess exactly on time at five o'clock, and we will reconvene at 8:30 tomorrow morning. Thank you very much.

(Whereupon, the opening meeting was adjourned at 5:00 p.m, to convene at 8:30 a.m. on Wednesday, September 27, 2001.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: ACRS Thermal-Hydraulic Phenomena Subcommittee

Docket Number: (Not Applicable)

Location: Rockville, Maryland

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.

Paul Intravia
Official Reporter
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