Some of the milestones in the review, very quickly: We received the code and the documentation in August of 2001, just a little over a year ago. We have gone through the initial presentations to the Thermal Hydraulic Subcommittee. We have asked for additional information, and we have presented the draft SER to the Thermal Hydraulic Subcommittee a month ago.

MEMBER SIEBER: Which one is that, the first one or the second one? I've got two different ones.

MR. LANDRY: The second draft SER.

MEMBER SIEBER: Okay.

MR. LANDRY: We've gone through a couple of iterations. What we have tried to do, in the first drafting of the SER, we tried to go through and just document what we had done in the review and then realized that, well, we didn't like that format; we didn't like all the material that we had in there.

So we went back and restructured the SER to follow in the CSAU format. Much the same as what Larry O'Dell just presented in the way the code work is structured, we went back and restructured the SER, all the steps of the SER, of the CSAU methodology.

The SER gives an overview of the PIRT

structure. We give an overview of the thermal hydraulic phenomena. We went into more depth in the thermal hydraulic phenomena than in some of the other areas because we had a number of questions and a number of areas of concern in reviewing the thermal hydraulics.

We have included an overview of some of the selected assessments that were performed. We gave an overview of code examination which the staff has performed and some of the parametric studies which the staff has performed in review of this code. We gave an overview of the uncertainty methodology and some of the conclusions.

The part that has been presented by Framatome presents the phenomena by transient phases. Now the PIRT part is pretty much the CSAU-presented PIRT in NUREG/CR-5249, with the exception that they have filled the gaps that were in that generic PIRT that was prepared for the NUREG report.

They have included a hot rod and a hot bundle in their model. They have also used a realistic linear heat generation rate rather than a very low peak linear heat generation rate, as was used in the NUREG report. They have used a frozen code version, as was described this morning.

The heat transfer modeling which the staff looked at, we found basically to be pretty good. We zeroed in very hard on the dispersed flow film boiling modeling, the reflood heat transfer modeling, because in the large-break LOCA the driving phenomena occur in the reflood.

In that review we took some disagreement with Framatome over the use of the Forslund-Rohsenow correlation. We have had disagreements with them over whether this is a wet contact, dry contact model; what is the nature of the model.

We basically came down to the point of agreeing to disagree. Because we went through the review and had Framatome take their worse case and specify from that worse case when the T-wall is greater than T-min, they would multiply the Forslund-Rohsenow correlation by zero, take it out of the evaluation. When that was done, we found that the calculation had no effect on PCT. Forslund-Rohsenow was not being invoked; it would have no effect on PCT.

Where it did have an effect was later in the quenching period. The temperature that was calculated going down towards the quench stayed anywhere from 5 to 10 to 18 degrees above the temperature that would be predicted using Forslund-

Rohsenow, and the time to quench was extended.

So we stepped back and said, okay, as far as PCT is concerned, whether you're using Forslund-Rohsenow or not, whether it is right or not is irrelevant because you are getting the same PCT.

MEMBER WALLIS: It seems to me some other issues could be resolved the same way, the agreement to do sensitivity studies around those issues.

MR. LANDRY: That's right. I am going to get to another one of those in just a few minutes.

I would say that the issue over Forslund-Rohsenow really deals with the nature of the model, the correlation. It is a correlation developed for liquid nitrogen being injected into a tube. We are talking about putting water into a bundle.

There is a research program underway right now up at Penn State, which the Thermal Hydraulic Subcommittee heard about when we talked about the draft SER last month, which would be using water in a bundle. That would produce data that would supposedly be much more accurate and much more representative of the phenomena one would expect to see in dispersed flow film boiling in a bundle.

The model which Framatome has chosen, used for decay heat is the ANS 1979 model. They have not gone to the full statistical decay heat modeling.

The assessment matrix which has been provided by the applicant includes separate effects and integral tests in their assessment. They did use a lot of the latest information, the information coming out of the 2D/3D program. This is information that was considered when NUREG/CR-5249 was put together.

When we did our review, we did a lot of spot-checking of the assessments, but we went in and looked at the results that were presented for the 2D/3D and, in particular UPTF, very hard. We felt that since this is full-scale and far more representative than some of the smaller-scale tests, we made a very hard review of what was done by the applicant in their assessment against the 2D/3D results.

We did spot-checking of the coding. Specifically, this is an issue which the Thermal Hydraulic Subcommittee has been after us on for some time, where we went into the actual source code itself, looked at the lines of the coding and said, do these lines of coding match what is in the documentation?

We found that there were just differences.

Well, when we started looking at what was in the code, we said, okay, what is in the code is right, but what is in the documentation hasn't been recorded exactly right. This is one of the things that Jim Mallay was talking about, that they are going back and looking at the documentation and working on improving the documentation for the code.

The staff ran a number of parametric studies. We looked at a few of the phenomena that were identified as unimportant phenomena that would be imported. Some of the things that we found, when we looked at phenomena such as the post-D&B forced flow heat transfer, virtually unimportant. When we looked at the effect of viscosity, of water viscosity, it was of very little importance.

MEMBER WALLIS: Ralph, this is taking their code?

MR. LANDRY: Using their code.

MEMBER WALLIS: Their input and everything?

MR. LANDRY: Their input.

MEMBER WALLIS: Did you use an approved platform?

MR. LANDRY: We used an HP.

(Laughter.)

They haven't certified our platform, but it is the same compiler and the same operating system that they use.

MEMBER WALLIS: Was this a platform which had previously been approved by the NRC for use for this purpose?

MR. LANDRY: We don't always QA our work.

MEMBER WALLIS: Are you going to give me a yes-or-no answer?

MR. LANDRY: We were using what is the same, what we understand to be the same platform, the same compiler, the same operating system that Framatome was using.

MEMBER WALLIS: But you ran that code, which is something we have been encouraging you to do --

MR. LANDRY: It was their code.

MEMBER WALLIS: -- and you've wanted to do. That is a step forward.

MR. LANDRY: Right.

MEMBER WALLIS: You did not run your own code for purposes of an audit or a check or --

MR. LANDRY: No.

MEMBER WALLIS: -- an independent verification?

MR. LANDRY: We are still taking baby steps along the way.

MEMBER WALLIS: Well, running your own code is going to happen before too long, I hope.

MR. LANDRY: It's going to, and I will get to that in just a minute.

But that gets to be very difficult to do because our code has very significant modeling differences. The RELAP5 mod 3.3, whatever it is, the latest, 3.3.3, or whatever the latest version is, has significantly different modeling in the reflood package. There's quite a few differences versus this code.

MEMBER WALLIS: Maybe that's a good reason for running it

MR. LANDRY: We will be getting to that --

MEMBER WALLIS: And if you get the same answer, then that would give you some confidence that different modeling doesn't give you a different answer.

MR. LANDRY: We're moving into that direction now.

MEMBER WALLIS: I think that is something that would really help the public confidence, if they could say, yes, he's run all these vendor codes to you, but now you've done something independent yourselves and it gives the same answer. Therefore, you have real confidence in it.

MEMBER LEITCH: Could you explain what the three curves are? What's the heavier curve versus the two lighter curves?

MR. LANDRY: That's what I'm trying to get to.

MEMBER LEITCH: Okay.

(Laughter.)

MR. LANDRY: We took the three-loop Westinghouse plant, that which Framatome supplied to us, and looked at the effect of wall drag, multiplying wall drag to increase the rod rate, which, in effect, as you increase rod rate, you retard reflood.

What we found was, where we had taken the viscosity term, where we had taken the heat transfer term, and multiplied those by two, five, and ten, we found almost no difference in the base curve. When we went into the wall drag model and increased wall drag, we found that the dark curve is the base case where wall drag is multiplied by one. When we increased the wall drag by two, we got a slightly higher PCT and a slightly later quench. Of course, you are delaying reflood; you would expect that.

When we multiplied wall drag by ten, we got a totally different transient. So that said to us wall drag is a very important phenomena. It gets back to, yes, reflood is a very important phenomena, which we had expected.

MEMBER WALLIS: Would that be acceptable, that sort of comparison? Just on the basis of PCT, it doesn't make all that much difference?

MR. LANDRY: It doesn't make all that much difference on PCT, but the occurrence of PCT is significantly different.

MEMBER WALLIS: It is quite different, yes. It is qualitatively different in several ways. So that would not be an acceptable prediction if that were -- in comparison with data?

MR. LANDRY: Right.

We have taken these analyses a little bit further, and this is brand-new. This was just done the end of last week.

We decided to look at the effect of momentum, since momentum keeps coming up as a question. We went into the code and simply put a multiplier on the virtual mass term, so that we would increase the momentum through the virtual mass. By increasing by a factor of ten, you see only a slight difference in momentum, the PCT and in heat transfer --

MEMBER WALLIS: Well, virtual massing increases the coupling between the phases. So in big virtual mass they tend to move together as a homogeneous mixture.

MR. LANDRY: Right, and we are making a much more homogeneous mixture.

MEMBER WALLIS: It doesn't really change the momentum.

MR. LANDRY: That's right.

MEMBER WALLIS: It changes the coupling between the phases.

MR. LANDRY: Right.

So this is just a first shot at trying to see what the effect of momentum was.

MEMBER WALLIS: It shows that when a question is raised about, say, virtual mass coefficient, which is not known very well for these systems, you can run a test and see if it matters?

MR. LANDRY: Right.

MEMBER WALLIS: It seems very appropriate.

MR. LANDRY: I said before when you asked --

MEMBER WALLIS: Excuse me. What did you

put in for the density in the virtual mass term?

MR. LANDRY: We kept it the same.

MEMBER WALLIS: They have a density which is the mixture density or it should be the continuous phase, which could be off by a factor of 50 or something?

MR. LANDRY: We left all that the same. We wanted to make as few changes as possible. This was only a first shot. We did this with the FLECHT SEASET test, then decided, well, that wasn't a good test to look at because it was a forced or fixed reflood rate. So if you change momentum, what are you doing with a fixed reflood rate? You're not making any change. So we went into the three-loop plant and made the change.

Our next step, since this is a large-break LOCA in a large plant, we want to go back and look at what is the effect if we get into a system that has much lower driving heads, such as a passive system.

MEMBER WALLIS: You made it ten times bigger? You made the coefficient of area mass ten times bigger than assumed by Framatome? You didn't make it ten times smaller as well?

MR. LANDRY: No. We're running out of time. We're trying to --

MEMBER WALLIS: Well, maybe next week you'll have that one.

(Laughter.)

Because if you are uncertain, you should go both ways.

MR. LANDRY: In the next few weeks we do intend to go back and look more; plus, we intend to go into our own codes in the next couple of months, depending on how our time is allocated. We want to look at some of the passive designs, run from the passive designs, and see with a plant that has a very low driving head what is the effect.

MEMBER WALLIS: This is a wonderful development.

MR. LANDRY: We're taking baby steps still.

MEMBER WALLIS: Well, soon you'll be running.

MR. LANDRY: Well, we have to walk first.

As Larry described, the methodology that they have used for uncertainty is non-parametric order statistics, and they have taken a variation on break type and size statistically, rather than fix the break size and then use all your parametric studies for one particular break size.

When that is done, the 59 cases which have been run, the staff looked at this and said at first, "Well, we have questions about using break size as a statistically-treated parameter." We looked very carefully at what Framatome had done and asked them to do another study for us.

Then we finally said okay, because what they have done is they have treated binomially the break type, whether it's a double-ended or a slot break. They have applied a uniform distribution to the size from double-ended guillotine down to their smallest-sized slot.

So they have not biased the break type or biased the break size. They are covering the entire spectrum on size. When that is done, they run the 59 cases, each with a different size. As you might expect, all the slot breaks end up at the lower size; all the double-ended breaks end up with a larger size.

They again end up with a double-ended guillotine as the worse case, which turns out, when we talked to them in-depth, this is pretty much the same case, the same break size as an Appendix K run on this plant would give, a different temperature, but the same break turned out to be the worst.

So we said, okay, take your worse-case

break and we want you to fix that break size and now go back and run 59 cases; vary all your other parameters, Monte Carlo method on all the variation of parameters, and rerun all 59 cases for only one break size.

When they did that, they found two points that came above this temperature and fifty-seven cases that came below that temperature.

MEMBER WALLIS: How far above did the two come?

MR. LANDRY: The two that were above were 20 degrees Fahrenheit above and 76 Fahrenheit above.

So we felt that, looking at what they had done, yes, they have captured the worst-break size. When you vary the parameters only on that one size, you don't go a very large amount above the predicted temperature.

So the staff's conclusions is that, okay, this is a different approach than we had anticipated, running break size as a statistical parameter. But because of the way they have done the study, and looking at what they have done, they captured the entire spectrum. They haven't biased the spectrum. They haven't truncated the spectrum at any point.

So they have again captured the large

break as the worst case. We have decided that, yes, we agree, that is an acceptable approach --

VICE CHAIRMAN BONACA: You have a guillotine break at about 2.8 or 2.7 square feet that is close to the limiting case. Does it mean that if they go into a smaller break size for the LOCA analysis requirement, you still get the same negative value?

MR. LANDRY: We weren't even addressing that. Our concern was, have they covered the entire spectrum?

VICE CHAIRMAN BONACA: I understand.

MR. LANDRY: Because they have covered the entire spectrum, this is a different issue than the question of, is it valid or not to restrict the size?

MEMBER WALLIS: Now, Ralph, I think they used a uniform distribution of break size, a probability distribution which was flat.

MR. LANDRY: That's right.

MEMBER WALLIS: And if they had better information about the likelihood of these large breaks or small breaks, they could feed that in, too. If that were based on good arguments and substance, you would perhaps accept that.

MR. LANDRY: Well, that's a different

question, and that is a project that is underway in the Office of Research at this point.

We had looked at what Framatome has done and said, this does not impact and that does not address what is being done in the Office of Research --

MEMBER WALLIS: Right, but the next step might be to say: Well, how likely are these breaks? And let's put in some better instruments of probabilities.

MR. LANDRY: That's right.

MEMBER LEITCH: Is the .1 square foot, is that the definition of a large-break LOCA?

MR. LANDRY: That's the definition that they have taken.

MEMBER LEITCH: So that's why there is no datapoints to the left of that .1?

MR. LANDRY: That's right. They had taken their lower limit as .1 times the area of the double-ended.

MEMBER LEITCH: Okay, okay.

MR. LANDRY: Staff SER conclusions: The staff concludes from the review of the documentation submitted by Framatome A and B that the S-RELAP5 realistic large-break LOCA methodology is structured consistently with the guidance of the CSAU methodological process and addresses the licensing requirements for a variety of similarly-designed nuclear power plants; specifically, three-loop and four-loop Westinghouse and the 2x4 CE designs.

MEMBER WALLIS: Ralph, we had this discussion before. Don't you want to say, "satisfactorily addressed" or something? Just the fact that it addresses the requirements doesn't mean it meets them.

MR. LANDRY: Yes, it does satisfactorily --

MEMBER WALLIS: You're going to put in something that says "adequately addresses" or something like that?

MR. LANDRY: Yes.

MEMBER WALLIS: So you are positively reviewing -- your review reaches a positive conclusion --

MR. LANDRY: Right, we have reached a positive --

MEMBER WALLIS: -- on the adequacy of this --

MR. LANDRY: There is a positive conclusion, yes. It applies to bottom reflood only.

This does not apply to upper head injection. This does not determine long-term coolability. This methodology does not address long-term coolability. That is an issue of specific hardware requirement. We agreed that long-term coolability is something that must be determined by the individual licensee, that they have adequate hardware.

That concludes the presentation.

CHAIRMAN APOSTOLAKIS: Graham, you're in charge.

MEMBER WALLIS: Well, it is nice to see the evolution of your review, the way it improves every time we see you.

MEMBER POWERS: The challenge that I'm still confronting here a little bit is I looked at the methodological aspects, and that's what he said on this slide, that it was methodological, but it is not evident to me that in formulating the treatment of large-break LOCAs that we haven't done that in the past in the conservative case to hide phenomena we just couldn't handle very well. Now, as we become more realistic, suddenly that hiding is no longer so easily done.

Now the one that I brought up more as an example than anything else is the spallation of oxide.

You know that when clad oxidizes, sooner or later it will spall. It simply cannot do otherwise. I, myself, have no idea when that spallation occurs. It won't occur when the oxide is very thin. It certainly will if it's very thick. But where it exactly occurs I don't know.

I do know that we are using fuels of higher burnup. They are more extensively oxidized to begin with. When that spallation occurs, of course, your oxidation kinetics are different; your heat temperatures are going to be different; your heat generation is different. But we don't seem to be looking at that.

MEMBER WALLIS: Well, I think one payoff from a realistic approach to these models would be that it would reveal areas where you need to know more.

MEMBER POWERS: Well, how would it ever reveal that you need to know more if you say, well, gee, I'll just use a parabolic oxidation model with no breakway in it?

MEMBER WALLIS: Well, it may be that that leads to questioning whether you should use such a simplified model. You realize that there are some things that are being hidden by assuming that model.

Hopefully, the models can advance. I have never found the one to answer the question. Maybe Ralph should be answering the question.

MR. LANDRY: I'm more than willing to let you answer it.

Well, the models can be varied. We can always go in and vary the model. But the question is, what is the basis for the variance? Do you have data to support the variation that you are doing?

We can go through and determine which models are important pretty easily just by making computer runs, but what is the basis on which we would say this particular model is not valid or this model should be used instead? Without adequate information, I would have a real hard time with an applicant saying, "Well, we're not going to accept this model. You have to use this model."

I have to have a basis for doing that. Plus, even though this is a realistic modeling, it still does have conservatisms in it, and if there is an area that we have uncertainty, we can always go in and restrict, put in limitations, put in conditions --

MEMBER POWERS: You can go in and you can work with the code all you want to. If it doesn't have the physics that's pertinent, you've got no answer. I mean, can you tell me that forming an oxide on a convex surface won't eventually spall, that it's thick enough? The answer is, yes, it will eventually spall.

What I can't tell you is how thick it is because I've never worked on it.

MR. LANDRY: And how do I model it?

MEMBER POWERS: Well, there are certainly things in the literature on how to model it. I mean this is not a completely unknown phenomena.

The question here that I am asking is, is it a new phenomena that has to be incorporated into these codes because the conservatisms that we had in the past, and are now going to be giving away, no longer hide the effects of these new phenomena?

MR. LANDRY: At this point, Dana, I don't know. I would have to have some basis for looking at the modeling, have to ask, perhaps ask the Office of Research: What do they know? Have they addressed this? Are they doing any work to address this question? What is their recommendation?

At this point I don't have a basis from a regulatory standpoint to move in that direction.

MEMBER SHACK: I think the Office of Research program on the LOCA will address that. I mean, they will be taking high-burnup fuel; they will be running it out to 17 percent oxidation and thermally shocking it, and one will then find out whether that will, in fact, spall it out.

MR. WERMIEL: This is Jared Wermiel, Chief of the Reactor Systems Branch.

Yes, we know the research program is going to be looking at the effect of different cladding materials in a LOCA, but I'm not aware, at least not from what I can recall reading about their program, that it is going to consider highly-oxidized materials at all, particularly materials that would have been oxidized to the point where, under these test conditions, they may spall, at least not that I can think of. That is something we can talk to them about, though.

Getting such material is not going to be easy, I wouldn't think. They may have access to highly-oxidized cladding. I'm not sure. I don't believe they do. But it is something we can talk to them about. This issue that you're raising, Dr. Powers, is I think something to think about.

MEMBER POWERS: I guess that's all I ask for.

MEMBER WALLIS: Anything else for Mr.

Landry?

(No response.)

Then I would like to hand this back to you, Mr. Chairman.

CHAIRMAN APOSTOLAKIS: Thank you.

You're all aware of the fact that at 1:30 we have a foreign visitor. So we really have to be here at 1:30. So we are recessing until 1:29.

There is a handout that I advise you to go over before we meet.

(Whereupon, the foregoing matter went off the record for lunch at 12:37 p.m. and went back on the record at 1:30 p.m.)

A-F-T-E-R-N-O-O-N S-E-S-S-I-O-N

(2:37 p.m.)

5) NORTH ANNA AND SURRY LICENSE RENEWAL APPLICATION

CHAIRMAN APOSTOLAKIS: The subject is the North Anna and Surry license renewal application. Mr. Graham Leitch, please lead us through this complex issues.

5.1) REMARKS BY THE SUBCOMMITTEE CHAIRMAN

MEMBER LEITCH: Okay. Let me just remind the Committee that on July the 9th, I think it was, we had a subcommittee meeting dealing with the license renewal application for North Anna and Surry.

At that time, we had an SER with comments. There were some open items and some confirmatory action items. In the meantime, a final SER has been issued which resolved those open items and confirmatory items. And there was a fairly significant rewrite of Chapter 4 dealing with TLAAs, which is the one part of the SER that was perhaps somewhat new since the subcommittee meeting.

So I would just remind the Committee that we want to be sure to leave enough time to talk about those TLAAs. Since they come near the end of the agenda, we want to be sure that we don't run out of time for that discussion.

So, with that introductory remark, then I'll turn it over to P. T., who will lead us through the discussion. P. T. Kuo. Thank you.

MR. KUO: Thank you, Dr. Leitch.

5.2) BRIEFING BY AND DISCUSSIONS WITH REPRESENTATIVES OF THE NRC STAFF AND DOMINION REGARDING THE LICENSE RENEWAL APPLICATION FOR THE NORTH ANNA AND SURRY POWER STATIONS AND THE ASSOCIATED NRC STAFF'S FINAL SAFETY EVALUATION REPORT

MR. KUO: My name is P. T. Kuo, the Program Director for the License Renewal and Environmental Impacts Program. Before I turn over this meeting to Dominion, I would just mention that because of the heavy snow today and the treacherous road conditions, some of our staff was not able to make it here today. But they are on the telephone. They will make their presentations and answer any questions you may have on the telephone if there is any.

CHAIRMAN APOSTOLAKIS: How can they make a presentation on the telephone?

MR. KUO: We have people to flip the charts for them.

CHAIRMAN APOSTOLAKIS: They are not flipping the charts at their homes.

MR. KUO: Right. But just in case that is ineffective, we also have other staff here to back them up.

Like Dr. Leitch said during the last subcommittee meeting in July this year, we had a few open items, confirmatory items, that were in discussion. Subsequently the staff has been able to resolve all of these issues and then, as you said, rewrote the section considerably.

For the safety review, Mr. Omid Tabatabai is the project manager. He is going to provide the Committee with an overview first. And then we will have the staff members to present the different subject matter.

I also want to report to the Committee that in the previous Committee meetings, I have said that we are working on a post-renew inspection procedure. I am happy to say that the procedure has been completed already, and it will be issued shortly.

Currently in terms of North Anna and Surry, we are working with the applicant on a Committee list. Hopefully we would be able to include in the SER a Committee list. That list will be used for the post-renew inspection.

So, with that, if there is no question for me, then I will turn the meeting over to Bill.

MEMBER LEITCH: P. T., that document, those post-review or inspection procedures, is there a document number associated with that yet?

MR. KUO: Not yet. That hasn't been issued yet because we tried to put together the list. And then we have that in there.

MEMBER LEITCH: Okay. Thank you.

MR. KUO: You're welcome.

MR. CORBIN: All right. I'm Bill Corbin. I'm the Director of Nuclear Projects for Dominion and would like to talk to you today a little bit about the Surry and North Anna application.

I know that we have indicated we want to make sure we save some time at the end for a discussion on TLAA. So I will try to move through my slides fairly quickly. Of course, if you have questions, please.

The participants. I have also brought some additional people with me today who are sitting here. As you can see, their names are up here: Paul Aitken, Mike Henig, Tom Snow, John Harrell, and also Ian Breedlove. These individuals I may be looking at over the course of the discussion depending on where our questions go.

The purpose of the meeting, I want to give you just an overview of the application. That was the agenda item that we have. So, moving along to number 4, make sure I'm on the right page here, the license renewal application itself was submitted on May 29, 2001. Our format wasn't such --

CHAIRMAN APOSTOLAKIS: Have you already given an overview to the NRC staff?

MR. CORBIN: Yes.

CHAIRMAN APOSTOLAKIS: This is not the first time they have seen this?

MR. CORBIN: No. That is correct.

CHAIRMAN APOSTOLAKIS: So you are just using slide number 3 from another presentation?

MR. CORBIN: Slide number 3 from another presentation? Really, we just put this together to --

CHAIRMAN APOSTOLAKIS: Provide NRC staff? We are not staff.

MR. CORBIN: Yes, ACRS.

CHAIRMAN APOSTOLAKIS: Right.

MR. CORBIN: Correct. Thank you very much.

CHAIRMAN APOSTOLAKIS: You are so welcome.

But the staff has seen this?

MR. CORBIN: Yes, they have.

On the background, page 4, the format is consistent with NEI 95-10, Rev. 3, NUREG. And what is really important about this slide I guess to recall is the Class of '01, which we consider ourselves to be members of, was not expected to use the draft GALL report. Obviously we did read and review it, but we're really not being held to it. We're one of the last in that genre. You also see Duke and Exelon in that same category.

With regard to the format, the sections that we will discuss today are sections 2, 3, and 4. This is strictly in accordance with 95-10, Appendix A on the UFSAR supplement and Appendix B. Our Appendix C is a little bit different in that it's an aging management review methodology, really not specifically required by any document, but we felt that it contained fairly significant information that helped to explain how we went about doing the aging management reviews; and then, finally, Appendix E for the environmental report supplement. There were no tech spec changes; hence, no Appendix D.

Section 2, then, using the 10 CFR 54.4 scoping criteria, we did develop a set of individual tables, four tables in all systems that were in scope and structures that were in scope. Then, to be complete, we also identified those systems and structures in its separate tables that were not in scope.

With regard to the methodology, we will talk a little bit about how we did the mechanical, civil, structural, and electrical; first, mechanical. We reviewed the documentation sources that we had in-house to identify intended functions. This includes equipment database system, UFSAR maintenance rule scoping, other documents that we already had in-house to identify those intended functions, then used our component database to identify specific components that supported each of those intended functions, and develop license rule boundary drawings. Specifically now we are talking about the mechanical portion of the review.

On civil/structural, we again reviewed documentation sources, similar to what we did in mechanical, although we did have some additional sources to look at, and used that to identify structural detail drawings to identify those members that supported the intended functions.

On electrical and I&C, a little bit

different approach here. The passive electrical/I&C components were screened on a plant-level basis. This is similar to what some previous applicants had done sometimes referred to as the spaces approach.

MEMBER LEITCH: Bill?

MR. CORBIN: Yes?

MEMBER LEITCH: Were there not some issues with scoping as far as the off-site power supply and how much of that should be included in the scope? Could you just refresh us on that discussion? I know the issue has been resolved, but could you clarify just what the resolution was?

MR. CORBIN: Right. When we initially put the application together, we identified those components that were specifically associated with the station blackout diesel in the way it was interconnected to our power supplies. We did not include off-site power and those things that are related to the switchyard in the scope.

As a result of the review performed by the staff and the discussions we had with the staff, we have included portions of the off-site power supply; that is, components and the switchyard, as they relate to getting back into the main power distribution system for the plant.

So that has been included. That was a change.

MEMBER LEITCH: Thank you.

MR. CORBIN: Okay. On the screening results, then, for all three areas, mechanical, structural, and electrical and I&C, we tabulated that in the application with a description; UFSAR reference, which included a hyperlink back to a copy of the UFSAR; license renewal boundary drawings, which also were hyperlinked; -- this drawing is basically for mechanical systems -- and the components subject to an AMR. So that was how we summarized in the application the results of the screening review.

Moving on to Section 3, make sure I'm on the right slide. Section 3, we had a text section for each portion of the application. In that section, you can read the bullets here behind me or on the slide in front of you.

We identified system and component description. We identified an AMR results table, which was hyperlinked, too; -- you can see that on the next slide, an example of it anyway -- whether there were generic topical reports that had been identified; and then a little more specifically what was the total set of materials for this particular part of the plant; the environments; the aging effects; and TLAAs if they were applicable. This is all identified in the application; finally, the aging management activities.

With regard to the table, we used a standard six-column table format. That obviously is going to change as we get into newer applications and the use of a GALL, but the time that our application was in the six-column format was still in vogue, I guess you could say. And you could see the component groups, the passive functions, material groups, environments, aging effects, and aging managing activities identified.

Any questions on section 3, how that was put together?

(No response.)

MR. CORBIN: Getting into time-limited aging analyses, then, the generic TLAAs had to do with reactor vessel neutron embrittlement; metal fatigue; EQ; tendon prestresses, not applicable to us, Surry and North Anna power stations, the containments do not have tendons; and containment liner plate and penetration fatigue.

I know we are going to have some additional presentations by the staff a little bit later, particularly on embrittlement and EAF. I know that that is an area you want to look at.

We would be happy to answer questions as the licensee if you have any with regard to some of those items or we can wait for the staff.

MEMBER LEITCH: I think if you're still going to be in the room, I think we could wait and hear the staff's presentation. Then we'll get into a discussion of this.

MR. CORBIN: Very good. Very good. Other plant-specific TLAAs, then, you can read the list here: the crane load cycle limit, flywheel leak-before-breaks, spent fuel pool liner, piping subsurface indications, and Code Case N-481 for the reactor coolant pumps.

Moving on quickly, -- I'm trying to go as quickly as I can here -- Appendix A on the UFSAR supplements, a long sentence here, but basically it's a summary of all of the programs. And the types of programs can include prevention, mitigation, condition monitoring, and performance monitoring. This follows the NEI 95-10 format.

In Appendix B, we had a total of 19 programs that were existing programs. Examples of that might be chemistry control, ISI, boric acid corrosion, et cetera.

We did identify, however, four new activities: buried pipe and valve inspections, infrequently accessed areas inspections, tank inspections, and cable monitoring. We ended up adding cable monitoring after our submittal as a result of our discussions with the staff and in answering some of their questions.

MEMBER LEITCH: Just a couple of questions in that area. Could you review for us the one time buried piping inspection? In other words, is this just an opportunistic inspection or at the end of the current license period if the opportunity has not presented itself, did you look or could you just go into that a little bit?

MR. CORBIN: Yes. It is our intention that by the end of the period, the current license period, the 40-year license, that we will deliberately go and look at each of the types of buried pipe that we need to.

However, we will be somewhat opportunistic up to maybe a year before that time. If we are out in the yard and digging, we will take it for that inspection. But with T-1 year to go, if we have not accomplished some of the buried pipe inspections, we will deliberately go out in the yard, dig a hole, uncover the pipe, and perform the inspection. So it's not strictly opportunistic.

MEMBER LEITCH: Okay. Thank you. The cable monitoring program, there is some testing there, I believe, for treeing; that is, cable that has been -- I guess, really, as I understand the situation, the first line of defense is to seal the manholes and the duct banks and so forth so that there is not moisture there. But in some cases, you may find moisture in spite of that or perhaps there are some cables that have historically been exposed to moisture. That leads to a testing program, does it?

MR. CORBIN: Yes, an evaluation. So our first line of defense, just as you say, is correct, is to try and inhibit the environment of flooded cables from existing. We have identified activities that we will perform to keep the water out of manholes, for example, or other places where groundwater could leak in.

But if we have a persistent issue with groundwater, then we will evaluate those cables for water treeing or other types of degradation for a cable.

MEMBER LEITCH: Has the exact nature of

that testing been established or is that something that we hope for further developments before the end of the current license period?

MR. CORBIN: We, like much of the industry, are waiting to identify a set of tests or a test that will be able to be performed that can explicitly show the type of degradation from water treeing or other mechanisms. We will follow the industry in terms of trying to identify a type of test that could be performed. Right now there really is nothing out there that we're aware of that explicitly tries to find that kind of degradation mechanism.

MEMBER LEITCH: Okay. Thank you.

VICE-CHAIRMAN BONACA: Regarding the existing activities, do you have to enhance any of them to address the license renewal or they are just the same activities?

MR. CORBIN: No. In fact, on the existing activities, in some cases, we do have to do enhancements. We have identified those in the UFSAR supplement and the commitments that go along with them where we know we need to do additional activities.

One right off the top of my head that I can think of is our civil/structural monitoring program, where we know we have got to include some additional inspections. That is just an example, but that is an existing program we do have to add new steps.

MEMBER RANSOM: Are you required to do anything in terms of inspecting for internal corrosion and buried pipelines or --

MR. CORBIN: The internal corrosion on buried pipelines, we are taking credit of our work patrol program in that buried pipe eventually will surface somewhere in a building or at a valve or in some other location, where we can as part of work patrol, for example, take the bonnet off the valve. And we have an opportunity to look at the inside of the pipe.

The assumption here, of course, is that the environment, the internal environment, is consistent, whether the pipe is buried or whether it has come up in a building.

MEMBER RANSOM: Well, in that line, do you do any inspection of piping in general or is that required?

MR. CORBIN: Well, on the line, yes, we will have committed to whatever is appropriate for that material in the environment. Carbon steel in a condensate environment, we might pick up chemistry controls in aging management activity. We might pick up flow system corrosion, for example. So whatever the line is, the material-environment combination, yes, we will have to do inspections on interior conditions.

MEMBER RANSOM: Is there any requirement to do any pressure testing of those components periodically or at relicensing?

MR. CORBIN: I am trying to think through. I am trying to catalogue all of the pipes and everything that we have got in the plant. I am not sure if we committed to pressure testing or not. Paul, do you know or can you recall?

MR. AITKEN: This is Paul Aitken. Pressure testing would be related to Class I in-service, what we call I think it is exam category BP, where we pressure test at a set frequency and go out and do visual exams, look for leakage. That would be the incidence. I don't think we would so much see it on the secondary plant as we would on the primary plant.

MR. CORBIN: Right.

MEMBER SHACK: You are going to replace the vessel heads on the North Anna plant. What are you going to do with Surry?

MR. CORBIN: We're replacing vessel heads on all four plants.

MEMBER SHACK: Four plants.

MR. CORBIN: And our current plan is to do that before the end of 2003 in each of the next outages for each unit.

MEMBER SHACK: That will involve you will have to cut holes in the containment to do that?

MR. CORBIN: That is correct. As a matter of fact, tomorrow we will start removing concrete on North Anna Unit II as the first of our four vessel head replacement programs.

MEMBER RANSOM: Why are they being replaced? Is there corrosion on the heads?

MR. CORBIN: This is the inspections that you do on the J-groove welds. I don't have a good diagram for you. The inspections on the J-groove welds are showing signs of --

MEMBER RANSOM: Cracking?

MR. CORBIN: -- cracking that will require repair work. We made a decision that, rather than spend the dose, time, and dollars to do repairs, which would be possible, that it was really more effective for us simply to go ahead and put a new head on.

And the opportunity presented itself. We found a head in the Framatome factory in France and were able to secure it. So that seemed like the better approach, and that is what we are going to do.

MEMBER SHACK: Now, when you repair the containment, how do you assure yourself you can meet the design requirements?

MR. CORBIN: When we put the containment back together, there really are two elements there. One has to do with the liner plate. One has to do with the concrete going back in. On the liner plate, we will obviously weld that out and do local leak rate testing as well as other forms of non-structured examination to assure ourselves that that has been welded back in. It is a fairly thin plate. I think it's a quarter or three-eighths inch plate. It's not all that thick.

Structurally, when we put the concrete and rebar back in, we do intend to perform a structural integrity test. It may turn in to be an integrated leak break test. We currently have an action in to the NRC for review to try and make sure that we perform the correct test to validate the structural integrity of the containment. But it will involve pressing up containment.

MEMBER SHACK: Is there a code case that

covers the repair of the containment or that is an engineering design that you do on an ad hoc basis?

MR. CORBIN: Ad hoc? I'm not sure I would go there, but we are doing it as part of engineering design. And we are trying to satisfy code requirements for both the liner and the concrete. What we would do on the concrete, for example, in accordance with IWL on the outside is look for any signs of cracking or deformation or degradation as a result of doing that, whether it is an SIT or IRT, whichever test we end up performing.

MEMBER SIEBER: That's usually done in conjunction with the design pressure test, where you map the cracks in the concrete, integrated leak rate test. This is a lower pressure.

MR. CORBIN: Right. We just have to decide which pressure that we are going to press containment to. There are still questions there. I am not being as explicit as I could because I just don't have all of the answers yet. We are still --

MEMBER SIEBER: I'm trying to help you.

MR. CORBIN: I know. And I appreciate the help. But we aren't quite all the way there in terms of exactly what kind of tests we are going to do.

We have made the commitment to press the containment. I will say that.

MR. KUO: If I may, I just want to answer, Bill, your question that yes, there is a code requirement for doing this structure integrity test, standard replant requirement also.

MEMBER SHACK: But we heard this morning they were going to do the integrated leak rate test. It doesn't seem to be a requirement, for example, through the design pressure test, which I would have thought that would have been my guess as to you have to cut a big hole in the containment.

MR. KUO: You are right that the strength integrity test and the leak rate test are being tested at different pressure. One is at the 1.1 *p* and the other is at design pressure.

MEMBER SIEBER: They are done for two different reasons, too. The integrated leak rate test is really testing the membrane, as opposed to the concrete reinforcement rod structure.

When you go and cut a big hole in containment, that is really what you are working with. You are working with the rebar. And you are working with the concrete and rearranging it as well as the membrane inside, which is the liner.

And I would have to look at the code, but it would appear that the design pressure test would be more appropriate when you're cutting a big hole in there and changing rebar and you have old concrete and new concrete.

MR. KUO: I'm sure the staff will review it. There are requirements for that.

MEMBER SHACK: Well, I'll explain. People have been cutting holes in containments now for some time, whether heads or steam generators. I would have thought by now we would have settled whether it takes a leak rate test or a design pressure test.

MR. KUO: I think for those in those cases, we did the leak rate test. Some of them are still contaminated, by the way.

MEMBER SIEBER: And that's different.

MEMBER SHACK: That's different.

MR. KUO: That's different.

MR. CORBIN: Okay. Moving on, just one comment we would like to emphasize about Appendix B, we did deal with an operating experience in two kinds of ways. First of all, our industry and in-house operating experience really is rolled in as part of our corrective action program. So that is an ongoing process.

But beyond that, as far as license renewal goes, we also took a review of operating experience looking for specific aging issues. We wanted to make sure that specific aging issues out there were addressed as part of our application, were built into the way we addressed our programs.

With regard to Appendix C, again, not required as a reviewer's aid, but it did offer some good information with regard to grouping of systems, short-lived components, and consumables, aging effects and mechanisms evaluating, gave some methodology information on how we went about doing the review.

Finally, Appendix E on the environmental report. You can read here it was done in accordance with the NEPA guidelines, NUREG-1437, and the GEIS. Severe accident mitigation alternatives were considered. In fact, the SAMAs was the area where we received RAIs. Those were resolved. The net result is environmental impacts of small and smaller than reasonable alternatives. That was the result of the review.

Closing remark simply is the effects of aging associated with Surry and North Anna will be adequately managed so that there is reasonable assurance the intended functions will be maintained consistent with the current licensing basis during the period of extended operation. This was the basis of our review. This was the conclusion we tried to reach.

And that concludes my remarks. If there are other questions?

MEMBER LEITCH: I had a couple of questions, I guess, Bill. One concerned flow-assisted corrosion. That is, I believe you were going to give us some information about how much piping had to be replaced as a result of being identified via the CHECKWORKS program and so forth. Would this be an appropriate time to talk about that?

MR. CORBIN: It can be. We did, as a matter of fact, provide some information to the staff to follow up. I think Omid is going to talk about that.

MR. TABATABAI: This is Omid Tabatabai. I am the project manager for North Anna/Surry. We have a staff presentation on this issue. Dominion has provided data, and the staff has verified and has studied that information.

MEMBER LEITCH: Okay. We can defer that, then, until we hear from the staff.

MR. TABATABAI: Sure. We will cover it.

MR. CORBIN: We also have an individual

here who is our flow-assisted corrosion lead if we get into some detailed questions who might be able to assist.

MEMBER LEITCH: Okay. Good. And the other issue I guess related to the method of Class I piping inspection with regard to the Summer crack. In other words, just what is the method going to be for inspecting that pipe? I think that may be another issue where the staff has a presentation.

MR. CORBIN: Yes. Again, we provided information to the staff that they reviewed. I think Omid is going to say the same thing.

MR. TABATABAI: Yes, exactly. We have a presentation on that issue.

MEMBER LEITCH: Good.

MEMBER FORD: And the same with the PTS question.

MR. CORBIN: And the PTS question, again, the same.

MEMBER LEITCH: Okay. Are there any other questions for Bill, then, at this time?

(No response.)

MEMBER LEITCH: Okay. Thank you very much, Bill.

MR. CORBIN: I thank you very much.

MEMBER LEITCH: Don't leave yet though. You can leave there, but don't leave the room.

MR. CORBIN: Thank you.

MEMBER LEITCH: And we'll turn it over to the staff for their presentation now.

MR. TABATABAI: Good afternoon. My name is Omid Tabatabai. I am the NRC project manager for the review of applications submitted by Dominion for license renewal of North Anna and Surry.

I would like to go over the agenda for today's presentation. We have presented our SER with open items to the ACRS subcommittee back in July. We were asked to provide more information and some data on the specific issues. These are the items that we have been asked to provide information.

The first topic that we are going to present is license renewal inspection. Mr. Caudle Julian, who is on the phone right now, will make this presentation. I will not talk about the license renewal inspection program.

The second topic is neutron vessel embrittlement. Barry Elliot is on the phone and Mr. Matt Mitchell, who will cover upper-shelf energy and PTS evaluation. We have Mr. Simon Sheng here. He will talk about the generic aspects of V. C. Summer

Mr. Leitch you asked and also its applicability to North Anna and Surry plants.

The last item that we have, Mr. Parczewski will talk about the trend of erosion/corrosion or flow-accelerated program at North Anna and Surry. These are basically the topics of our presentation today.

I would like to go over quickly on the North Anna and Surry power plants. They are all three-loop Westinghouse design. The current license, operating licenses, will expire on April 2018 and August 2020 for North Anna Units I and II. For Surry Units I and II, the operating licenses will expire on May of 2012 and January of 2013.

As far as staff's review milestone and schedule, we received the applications on May 29, 2001. The staff issued a safety evaluation report with open items on June 6. We issued the safety RAIs back in November 2001. And, as I mentioned, we briefed the ACRS subcommittee back in July of 2002.

The staff has met all the milestones. And according to the new review schedule, 22-month review schedule, the Commission is expected to announce its decision by March of 2003 if a renewed license is approved.

Safety evaluation with open item was issued on November 5, 2002. The staff has divided safety evaluation into four chapters. Chapter 1 talks about a general discussion and introduction; Chapter 2, evaluation of scoping and screening methodology by the applicant. Chapter 3 talked about the evaluated and reviewed aging management programs. And in Chapter 4, we performed a time-limited evaluation of time and aging analysis.

The SER open items, we had one open item in Chapter 2, scoping and screening. It was related to the station blackout issue that Mr. Leitch asked about, including off-site power into the scope license renewal. That was one of the open items we had.

We had three open items in aging management program, aging management review, Chapter 3, which related to non-EQ cable program. And we had four open items in TLAA issue, which related to fatigue and environment and assisted fatigue issues. SER with no open item, in fact, we saw all the open items. And there were no outstanding issues in our SER right now.

This is basically my presentation. I would like to ask Caudle Julian to start his presentation on license renewal inspections. If there are any questions for me, I will be happy to answer. Caudle, can you hear me?

MR. JULIAN: Very good. Can you hear me okay?

MR. TABATABAI: Yes.

MR. JULIAN: Okay. I would like to run through the presentation from start to finish, if possible, since I can't see you. And then I will answer questions at the end.

Our first slide, which the Committee had seen before, describes our license renewal inspection program. We are following our manual chapter 2516 and license renewal inspection procedure 71002. We provide a site-specific inspection plan for each applicant, and this is done for the Dominion case. The schedule we're following is the standard 30-month model of NRR. And we can do the inspections at set times.

The resources that are needed for our inspection are a five-member team. We have been carrying the same team as long as we can, but when we lose them, which happens every once in a while, we have a training program for replacement.

The first inspection that was done at North Anna/Surry was the scoping and screening inspection. The objective of that was to confirm that the applicant tests included all appropriate systems, structures, and components in the scope of license renewal as required by the rule. It was one week in length, conducted February 4th to 8th at the corporate engineering offices because that is where they did most of the work for building their application.

Some typical results from that inspection are that we found that the applicant had significantly expanded the scope of components to be considered for aging management considerations due to the staff concern over non-safety-related to safety-related interactions.

I think we have talked about this issue before. It is a concern that non-safety-related piping might fail due to aging and do damage to safety-related. We found that the applicant had done a wide expansion of their original scope of components, and we thought that was the conservative thing to do.

Another issue was that we do a walk-down and containment during a refueling outage as part of our inspections. The only thing we found that was of concern at all to us there was that the Surry component cooling water piping inside containment had a lot of corrosion. The applicant had known this for a long time and periodically had put it in their corrective action systems, but it didn't seem to be a very organized program for looking at this.

While we were there, the applicant took some ultrasonic measurements to confirm that the piping is not corroded to below minimum wall. Since then, they have developed a procedure as part of their general condition monitoring program to continued to monitor the corrosion of this piping to see that it is not yet too thin.

The second inspection was the aging management inspection.

MR. ROSEN: One question.

MR. JULIAN: The objective of that is to confirm that existing --

MR. TABATABAI: Excuse me, Caudle. There is a question for you.

MR. JULIAN: Okay.

MR. ROSEN: On the component cooling water piping inside containment corrosion, does that extend outside containment as well? And if so, what is being done with piping outside containment? Can you characterize the kind of corrosion it is? What is the root cause? What kind of degradation is being seen?

I understand it is not below wall, but I would like more information than that.

MR. JULIAN: Okay. I had a real tough time hearing the question, but I understood that your concern is or question was about piping, both inside and outside. Both of those pipings, inside and outside, are included in their general condition monitoring program.

The cause of this piping corroding is that it's often chilled water. In fact, containment with a fairly heated atmosphere, the chilled water tends to have condensation on it all of the time. And that is a common problem that we see at a lot of places.

MR. ROSEN: Okay. So now I understand it is exterior corrosion?

MR. JULIAN: Exterior, yes. I'm sorry. Exterior corrosion on the piping, rusty. It's rusty looking.

MEMBER LEITCH: So though the program includes both piping inside containment as well as outside containment, --

MR. JULIAN: That is correct.

MEMBER LEITCH: -- the problem is really just occurring on the inside containment basically due to sweating of the pipe?

MR. JULIAN: Yes, yes. And what we thought would be a good thing that we see other places is to establish set places to come back and monitor periodically and have trending so that you can see how not only what the current condition is but what are the trends.

MR. ROSEN: And that's because only the piping within the containment carries the chilled water? Outside containment component cooling water is not chilled?

MR. JULIAN: Well, it has to be cooled down as it leaves the heat exchangers and has been to the containment, but it's worse inside containment because of the temperatures. With the pipe continually wedded at an elevated temperature, it tends to corrode worse than otherwise.

MR. ROSEN: How bad was the corrosion?

MR. JULIAN: Well, it looks bad. It looks nasty. But, as I say, we did take some spots that looked the worst and had the applicant to smooth them up and take ultrasonic measurements to confirm that they had not corroded to below min wall.

MR. ROSEN: Well, that is not very comforting. Min wall is one thing, but how much corrosion are we talking about? Are we talking about surface corrosion or is it --

MR. JULIAN: Yes, surface corrosion.

MEMBER FORD: There was a question raised at the subcommittee meeting about a difference in materials between Surry and North Anna. You didn't see the same problem and the same situation at North Anna, I understand.

MR. JULIAN: No, I don't believe we did.

MEMBER FORD: Was that due to difference in relative humidity or was it due to difference in materials composition?

MR. JULIAN: I'm afraid I don't know the answer to that.

MR. CORBIN: The significant difference between Surry and North Anna in this regard is that North Anna has a better coating system on their component cooling water piping.

MEMBER FORD: So there's a reason for the difference.

MR. CORBIN: Correct.

MEMBER FORD: Okay. Good.

MR. CORBIN: I'm sorry. Bill Corbin.

MR. ROSEN: And the solution to this problem at Surry, I guess, is that it will be monitored? Is that what I understand?

MR. JULIAN: Yes. They have a monitoring program and are going to continue to measure it, take repeated measurements at set spots in the corrosion.

An alternate solution, of course, that many people employ is to replace the piping, but they're not going to want to do that until it gets to the point where it is really necessary.

MR. ROSEN: So we're just going to watch this piping corrode away from the outside at Surry? Is that what the plan is? And the staff has agreed with that? Is that what I understand?

MR. JULIAN: Yes. That's generally the program that they're following, is to monitor the piping and to take action to replace it before it gets to the minimum design wall.

MR. JULIAN: Okay. May I continue on?

MR. TABATABAI: Go ahead, Caudle.

MR. JULIAN: Thank you.

The next inspection is the aging management review. The objective there was to conform that existing aging management programs are working well and to examine the applicant's plans for establishing new aging management programs and enhancing existing ones.

That was two weeks in length in April and

May. As with the Duke plant, which we told you about earlier, we did one week at each site, one at Surry and one at North Anna.

Two observations of interest there were at Surry, the applicant was out looking at things ahead of us. We went over and looked at some manholes in the switchyard. The applicant was surprised to find some water in those electrical cable manholes.

The solution to that as of now has been to do periodic inspections. I understand now we're doing inspections twice per week. They're looking for an engineering solution. And that will probably be to redesign a manhole to put in automatic sump pumps. These manholes in question do not have automatic sump pumps or drains in the bottom.

We also found that in the past both plants had found containment concrete anomalies and had made repairs. You have probably heard of those issues where they started looking closely at containment and found in the pieces of construction wood that was left in the concrete. Those had to be removed and repairs made.

The last and third, optional, inspection that we did was one of open items. That was conducted in September. We found that the applicant had made some progress in making some of the plant procedures changes to programs that needed to be done for enhancing aging management programs.

And, most important to us, they had established a tracking system to keep up with the future actions that they had committed to do. That was one of the concerns that caused us to do the third inspection.

VICE-CHAIRMAN BONACA: I had a question on the flooding of electrical cable manholes. Who found those? Who found there was flooding there?

MR. JULIAN: Again I'm having trouble hearing. I thought the question was who found those?

MR. TABATABAI: Yes, Caudle. The question was who found the flooding cable manholes?

MR. JULIAN: The applicant did that. They looked at a representative sample of manholes up at North Anna before we got there. And then we also peaked into them while we were there.

When we got to Surry, they had been looking at some of those manholes. The ones we selected to look at at Surry were not the normal safety-related cable runs within the plant. We were interested in the wiring that goes over to the switchyard at Surry station, service tents. And those manholes do not contain safety-related cables, but they are brought into the scope of license renewal because of the station blackout concern.

VICE-CHAIRMAN BONACA: Thank you.

MR. JULIAN: But they found it. One of the issues that we discussed with them was that North Anna has a very well-established procedure and program for periodically going around and monitoring the condition of manholes, but Surry has yet to develop one of those. So Surry is now committed to do that in their future as part of the agreement that we have had with the staff.

MR. TABATABAI: Thank you, Caudle.

MEMBER LEITCH: I just want to be sure I understand the total scope of the inspection program. There was one week scoping and screening in the corporate office?

MR. JULIAN: Correct.

MEMBER LEITCH: And then a physical inspection at each plant, one week at each site?

MR. JULIAN: That's correct.

MEMBER LEITCH: And then two weeks in the aging management review? That was in the corporate office?

MR. JULIAN: No. Let's see. You've got

the first part right. The scoping and screening was one week long. And it was done all at the corporate office because that is where all of the engineering work was done. Then the aging management programs were done one week at Surry and one week at North Anna.

The reason, of course, for doing one at each site is that we wanted to do a lot of walk-arounds in the plant and take a look at a lot of the plant equipment.

So it's not just a paper review. Our inspectors have assigned systems. And they go out with the applicant representatives and walk down those systems.

MEMBER LEITCH: Then the open item inspection, what was that, one week again at --

MR. JULIAN: That was just a few days, just took two or three days, at the engineering offices. Those are primarily chasing tracking systems and changes that they needed to make to procedures.

MEMBER LEITCH: Okay. Thank you.

MR. JULIAN: One of the questions I think we had last time that I wasn't able to make was about the overall condition of the plant. We concluded from our look that the plant was in good condition. And what that meant to us was that the plant was clean and everything was painted. There was little or no corrosion of components wherever we went. There are very few leaks and ones that existed are tracked for repair. We thought overall that North Anna and Surry, both plants, are being very well-maintained.

MR. ROSEN: That's with the exception of the component cooling water piping in containment. Is that correct?

MR. JULIAN: Right, with exception of component cooling water, correct.

That concludes my presentation. Any more questions?

(No response.)

MR. TABATABAI: Thank you, Caudle.

Barry, you are actually the next presenter to talk about pressurized thermal shock.

MR. ELLIOT: This is Barry Elliot of the Materials and Chemical Engineering Branch. I am going to discuss the PTS evaluation that was done by the applicant. First I am going to begin with a little background. That is the first two slides.

The PTS evaluation is done in accordance with the rule 10 CFR 50.61, the PTS rule. It requires all licensees to determine whether the reactor pressure vessel beltline materials exceed the PTS screening criteria and to evaluate surveillance data to determine the impact of the data on the PTS evaluations.

The PTS screening criteria is a material property. PTS screening criteria is 270 degrees Fahrenheit for axially oriented welds and base metal and 300 degrees Fahrenheit for circumferentially oriented welds.

The RT_{PTS} values are the sum of three quantities: the unirradiated reference temperature, the increase in reference temperature resulting from irradiation, and margins. The increase in reference temperature is a product of a chemistry factor and a fluence factor. And the chemistry factor is dependent upon the amount of copper and nickel.

When the Charpy test is performed, the increase in transition temperature is equivalent to the increase in transition to temperature from the Charpy transition temperature.

The margin term is to account for uncertainties in copper, nickel, neutron fluence, unirradiated reference temperature, and calculation procedures. The margin curve is a part of two sums: the standard deviation for the increase in reference temperature, which is equal to 28 degrees for the weld. This particular value is gotten from an industry-wide surveillance database and also the standard deviation for the unirradiated reference temperature.

Next slide. Chemistry factor may be determined from surveillance material or from the chemical composition of the material. This is according to the rules. Our chemistry factor is determined from surveillance data if the surveillance data meet the credibility criteria in the rule. Chemistry factor can also be determined from tables and rules based on the percentage copper and the percentage nickel in the materials. And, finally, the material surveillance data shall be evaluated to determine whether the RT_{PTS} value for the beltline material is a bounding value.

Not in the rule but an important part of the staff's evaluation and applicant's evaluation is that the neutron fluence calculation should be done in accordance with Reg. Guide 1.190. This is a staff guidance document.

That is the background for the PTS rule. Next is an evaluation done by both the staff and the applicant on the surveillance data. This discussion is going to be about the Surry-1 material surveillance data. And it's limiting weld. The reason for that is that this Surry-1 material surveillance data has a weld, an axial weld, which at the end of the license renewal term has an RT_{PTS} value of 268.5.

The other three reactors are significantly below that. North Anna I's value is 191. North Anna II is 228. And Surry II is 219. And the highest copper in any of those reactors is .19 while the Surry I reactor axial weld has a .3 copper in its weld.

There were nine data points for the limiting surveillance weld. They were done by three different vendors. They were done in the '70s, '80s, and '90s. And the applicant recalculated all of the neutron fluences for all of the data using Reg. Guide 1.190, though all of the data would be on the same methodology.

The applicant evaluated the data, and the data did not meet the credibility criteria in the rule because of large scatter in the data. The applicant then used the methodology in the tables to calculate the RT_{PTS} value.

The staff was concerned that there could have been a bias in the data. So we ran a *z*-test. The *z*-test has a five percent significant level, indicating that the surveillance data are consistent with the data used to develop the table in the chemistry factor.

The conclusion from our *z*-test was that the use of the chemistry factor from the table in the standard deviation for the increase in reference temperature of 28 is appropriate. That is the evaluation of the surveillance data.

Next slide is the summary of the PTS evaluation using the chemistry from the limiting weld. The RT_{PTS} value is 268.5 at that end of the license renewal period. The RT_{PTS} value is calculated using a chemistry factor from the tables and is based on the best estimate copper and nickel for the weld. All neutron fluence for the weld was also calculated according to Reg. Guide 1.190.

The staff confirmed that the RT_{PTS} value was 268.5. And for Surry I, the unirradiated reference temperature is -7, which is a generic value. The increase in reference temperature was 206. And the margin curve is 69.5.

The staff's conclusion is all materials will be below the PTS screening criteria for the end of the period of extended operation. That is the summary of the staff's evaluation.

MEMBER FORD: Barry, I've got a procedural question for you. If that RT_{PTS} value by calculation had come to 270.1, then you would ask them the utility to go into some remediation program. Is that correct?

MR. ELLIOT: I can't hear the question.

MEMBER FORD: The RT_{PTS} value. Can you hear me now?

MR. ELLIOT: Can you just tell me what the question is?

MR. TABATABAI: Barry, the question is what would happen if the RT_{PTS} value were 270.1? What would we ask them to do?

MR. ELLIOT: Okay. 270.1, the licensee would have two alternatives. You can do flux reduction so that the value would be below the screening criteria, which is probably what they would do if that were the case, or they can do an analysis that demonstrates that operating above the value would be acceptable.

MEMBER FORD: Okay. So you've got one and a half degrees Fahrenheit margin by the current calculations. Could you chew up that margin just for the uncertainty in your copper and nickel contents?

MR. ELLIOT: The margin of one and a half degrees includes margin and nickel. That would be the margin curve.

MEMBER SHACK: It's a magic number.

MEMBER KRESS: It's a speed limit. You get a ticket if you go over.

MEMBER FORD: Does the staff have any procedure? When you get to close margins at one and a half degrees F., by the procedure, does the staff have any second thoughts as to how safe this is? I recognize that 270 degrees F. has got all sorts of uncertainties in it and margins. At what point does the staff start to look at these things the second time or a second --

MR. ELLIOT: As long as an applicant or a licensee is below 270 for the axial weld, no matter how low it is, that is all they have to do.

MEMBER KRESS: I am concerned about 271.

MEMBER FORD: Yes. It seems very, very arbitrary. I recognize the 270 criterion is a fairly arbitrary number, but at what point should you start to get worried?

MR. ELLIOT: What time do I start to get worried?

MEMBER FORD: Yes.

MR. ELLIOT: I get worried every day about 7:45, when I get to work, but I am not worried about this plant. This plant has nine data points which we looked at carefully, which the licensee ha evaluated, which we evaluated.

We even did a statistical evaluation. We don't normally do that, and it's not in the rule. But because they were close to the screening criteria, because of the large amount of data and the data itself, we decided to make an extra step, which was to do the statistical analysis.

That gave me more assurance that the value is a pretty good value.

MEMBER SHACK: Barry, what is the statistical test really telling you? What were you trying to determine from the statistical test?

MR. ELLIOT: What we do is we compare the measured value for the actual surveillance data points to the predicted value for that surveillance data point. And then using the *z*-test and the standard deviation for the model, which is 28 degrees, we determined that it was within the limits of the 95 percent confidence limit. It had a five percent significance level.

MEMBER SHACK: Since you determined that the surveillance data wasn't applicable, why wouldn't you just calculate it from the tables?

MR. ELLIOT: You do calculate it from the table. What I was concerned about, in essence, the rule says if the data is credible, use the data. In this case, the data was not credible. So you couldn't use the surveillance data according to the rule. So you automatically fall back to the table. And that's what they did.

I was a little concerned that there wasn't a sufficient margin, that there was more scatter in their plant-specific surveillance data. There are nine data points, but the analysis shows that it is what would be expected from the database.

MR. TABATABAI: Any more questions for Barry?

(No response.)

MR. TABATABAI: Okay. Thank you, Barry.

MR. ELLIOT: Okay. I'm going to stay on the line for Matt's presentation, and I am going to get off after that.

MR. TABATABAI: The next presenter is Matt Mitchell. He is a senior materials engineer, and he is going to talk about upper-shelf energy.

MEMBER SHACK: Just before you start, Matt, did they already run a low leakage core?

MR. MITCHELL: I think I would have to ask the licensee to explain how they define their core design.

MR. HARRELL: This is John Harrell from Dominion, supervisor for nuclear safety analysis. Yes, we do operate with a low leakage core. We monitor peripheral assembly relative power distributions. Those would be in the realm of, say, .4 relative to the average power distribution that constitutes what we consider to be a low leakage pattern already for Surry Unit I. We have flux impression inserts in those peripheral assemblies.

MR. MITCHELL: Okay. Then to proceed with the discussion on the upper-shelf energy issue, our first viewgraph is merely a background slide. Bullet 1 reiterates the specific regulatory criteria from Appendix G to 10 CFR Part 50 regarding upper-shelf energy requirements for reactor vessel beltline materials.

Of course, the item of interest in this discussion is criteria 2 regarding the end-of-license upper-shelf energy. Hence, extending the license, increasing the fluence will lead to a further reduction in the projected Charpy upper-shelf energy as we move forward.

The second bullet is a reiteration of what

I will call the equivalent margins analysis clause, which is found in Appendix G to 10 CFR Part 50. It provides for the ability for a licensee or for the applicant to perform a demonstration to show that lower values of Charpy upper-shelf energy are, in fact, adequate for continued operation, an operation until the end of their license.

It is worth noting, I think, at this point that the accepted technology for performing equivalent margin analyses is what I would call sure technology. We have been using this approach based upon elastic/plastic fracture mechanics, J-integral tearing modulist evaluations now for the better part of a decade. It is well-documented in Regulatory Guide 1.161 and in Appendix K to Section XI of the ASME code.

So what we have here is a case where we have merely reevaluated the condition of the vessel based upon the higher fluence values to be expected at the end of the period of extended operation using an established technique.

MEMBER SHACK: What will their projected Charpy energies be?

MR. MITCHELL: Well, you've gotten me to my backup slide. I'll go straight there. Based upon the information that the licensee submitted and the staff is in agreement with the values they provided, for Surry Unit I, which actually has both the limiting axial and limiting circumferential weld, when you look at the Surry Unit I and Surry Unit II vessels. On the circumferential weld, it is approximately 42 foot-pounds on the axial, limiting axial, weld, it is about 43.6 foot-pounds would be what it would be projected out to be.

MEMBER FORD: What am I missing? Isn't it 50 pounds? You can't go below 50 foot-pounds?

MR. MITCHELL: Per the specific criteria in Appendix G to 10 CFR Part 50, 50 foot-pounds is the limit. If you go beyond that limit, then you require the equivalent margins analysis. And it was the equivalent margins analysis that was performed by the applicant for the Surry Unit I and Unit II vessels.

MEMBER FORD: Again, isn't it exactly the same situation with the PTS situation that you're nudging against what the current rules say?

MR. MITCHELL: In effect, you could draw a parallel between the 270-degree screening criteria in 50.61 and the 50 foot-pound limit in Appendix G. If you wish to draw another parallel, this would be akin to an analysis like a Reg Guide 1.154 analysis, which could be done if a facility went above the 270-degree screening criteria relative to 50.61. This analysis is considerably less cumbersome, however, than a Reg Guide 1.154 analysis would be for PTS. Certainly there is parallelism between those concepts.

MEMBER SHACK: If it was 51 foot-pounds, you're home free.

MEMBER FORD: You're okay. Just as kind of a concerned citizen, professional engineer, does it not make you feel uncomfortable?

MR. MITCHELL: I'll just suggest that -- and particularly the words are valid with respect to the PTS screening criteria. It is a screening criteria. It is a criteria at which it is sort of a yellow caution light in a sense, if you will, to draw additional attention to and warrant further evaluation of.

It's not intended to be a hard stop, if you will. The 50 foot-pound limit with respect to upper-shelf energy is also not intended to be a hard limit. So it is open to further --

MEMBER FORD: But Barry just said for the PTS, for instance, 271, you have to start to go through some gyrations in terms of annealing or whatever you are going to do.

MR. MITCHELL: Well, in terms of first looking at issues or the possibility for flux suppression further analysis, whatever methods would be available to the licensee, what would be a warranted step relative to a screening criterion.

VICE-CHAIRMAN BONACA: Now, these speculations and the results of them, of course, depend on certain assumptions of fluence at the end of license that you will monitor or they will be monitored by licensee to the specimens and all kinds of stuff.

So when you get a result and it is closed, the criteria, what kind of reputation does take place during the 20 years' operation? How do you assure that you are staying within those criteria?

MR. MITCHELL: Well, let me answer one part of the question first. With regard to the fluence values which are used in this evaluation, as we were the ones used in the PTS evaluation, it was confirmed that those values were consistent with the staff guidance in Regulatory Guide 1.190, which was recently issued. Therefore, the staff felt confident that those values were accurate projections of the fluence out at the end of the extended period of operation.

With regard to continued monitoring, we also have provisions established for the licensee to continue with a reactor pressure vessel monitoring program moving forward consistent with the intent of Appendix H to 10 CFR Part 50. So there would be measures in place to continue to acquire data as appropriate. And that should be documented in the staff's safety evaluation.

VICE-CHAIRMAN BONACA: And that includes a program, I believe, of collection of data and how frequently comparisons will be performed in the department. I mean, certainly you don't want to get to the point where some time in the 20 years of extended operation, you are crossing over that line.

MR. MITCHELL: Yes.

VICE-CHAIRMAN BONACA: Right?

MR. MITCHELL: It would be certainly the intent of the surveillance program is to provide you with information in advance of when you would be projected. Again, keep in mind I guess we should emphasize the numbers that we have here are those that are projected to occur at the end of the extended license. Data acquired before then should give you lead time.

VICE-CHAIRMAN BONACA: Now, we are looking at this data because we specifically said we wanted to see it. Now we see it coming through and show some results which are more borderline than I expected.

So I would expect from now on licensees will be required to submit this information for all of the applications.

MR. KUO: Yes, Dr. Bonaca. We have made it clear that the applications should have this kind of information.

VICE-CHAIRMAN BONACA: Yes. And you'll let us know if that is within the existing guidance or if we need to change the guidance to be able to secure this information.

MR. KUO: Sure.

MR. TABATABAI: Actually, Dr. Bonaca, this was one of the items we discussed during a workshop we had a few weeks ago with the industry, asking specific information on neutron vessel embrittlement.

VICE-CHAIRMAN BONACA: Thank you.

MEMBER LEITCH: Is the bottom line on that chart intended to be Surry II?

MR. MITCHELL: No. Actually, it's also intended to be Surry I because the two bottom lines represent the circumferential/limiting axial weld. And both the limiting circumferential and limiting axial weld were actually found in Surry I relative to Surry I and Surry Unit II.

MEMBER LEITCH: So Surry Unit II is above those numbers there?

MR. MITCHELL: Yes.

MEMBER LEITCH: For both axial and circumferential?

MR. MITCHELL: That is correct.

MEMBER LEITCH: Okay. Thank you.

MR. ROSEN: Is it above 50?

MR. MITCHELL: No. There are materials in the Surry Unit II vessel which do also drop below 50 foot-pounds. However, since they are bounded by the Surry Unit I materials, the evaluation or review of the evaluation of the Surry Unit I materials would bound those. If these pass, they would also pass, the equivalent margins.

MEMBER LEITCH: The SER refers to 48 equivalent full power years, but we are licensing the plant for 60 years. Is it conceivable that in 60 years, one could go above 48 full power years?

MR. MITCHELL: Depending upon the operational behavior of the plant, the availability and capacity factors of the plant operates at, it would be conceivable. I am not at this point aware.

And perhaps the licensee would be in a better position to answer what the potential is for that to occur.

MR. HARRELL: Yes. This is John Harrell again from Dominion. Each reload is evaluated for its contribution of fluence in the place that it is expected from approximately 488PY.

So there is an ongoing tracking mechanism for evaluating the effect of a reload core design on that, and that includes a consideration capacity factor as well as the relative power distributions in the core. Of course, it also considers the effect of many power operatings that occur in the interim.

So there is ongoing monitoring of the effect of full power years relative to the limitation that is present in the TLAA.

MR. ROSEN: What kind of assumption are you making for operating capacity factor?

MR. HARRELL: Currently 90 percent.

MR. ROSEN: So it would have to exceed 90 percent in order to push this up closer to the limit?

MR. HARRELL: More precisely, it would have to exceed 9 percent on average.

MR. ROSEN: On average, right. Just following along, Dominion in Surry and North Anna have typically recently, at least, done better than that, haven't they?

MR. HARRELL: That is correct. Recently they have. But prior cycles have not averaged to an average of 90. Again, the reloaded evaluations of the effects of relative power distribution and capacity factor would evaluate the effects of capacity factor in excess of the projected 90 percent average.

MEMBER LEITCH: But we're not licensing the plant for 48 full power years. We're licensing it for 60 years. Should we be?

MR. MITCHELL: Maybe as a point of clarification, the staff expects that if the licensee comes to possess information which would suggest that they would need to update this analysis because they are projecting now a higher fluence value at the end of the period of extended operation, whether it be because they have operated a higher capacity factor or for some other reason, they would update their analysis, as appropriate.

Any analysis of this type done at some point in the future is subject to the assumptions that go into it. Those assumptions may not be accurate or found to be less than accurate at some point in the future. Licensee applicant should revise their evaluation if necessary.

I think we have probably covered actually the information that is on my second and third actual slide. Obviously there were materials in Surry Units I and II which did fall below the criteria. The applicant performed their equivalent margins analyses, which were provided to the staff in report BAW 2323.

The staff based upon the information that we had available in our reactor vessel integrity database and based upon information the licensee provided was able to go through and to independently perform our own equivalent margin analyses.

The conclusions of both the applicant's and the staff's analyses were, in fact, the same, that they did demonstrate acceptable equivalent margins analyses for continued operation through the end of their extended license.

MEMBER SHACK: When do they have to recompute their pressure temperature limits for cooldown?

MR. MITCHELL: Typically, they would have to recalculate either upon expiration of the pressure temperature limits if they are established at some value less than the fluence value at end of license. They would need to reevaluate whether they would need to be recalculated if they come into possession of surveillance data, fluence data, or other information which could modify the period of applicability of the pressure temperature limits.

I'll defer back to the licensee because I am not currently aware as to where the pressure temperature limits for the Surry units --

MEMBER SHACK: The answer is you don't routinely calculate that for the license renewal. That is considered an operation, a current licensing operation.

MR. MITCHELL: It is currently a current licensing basis. It is something they would be carrying forward that they look at as they go into the period of extended operation.

Are there any more questions?

(No response.)

MR. TABATABAI: Thanks, Matt. Our next presenter is Simon Sheng. He will talk about V. C. Summer.

MR. SHENG: This is Simon Sheng of the Materials and Chemical Engineering Branch.

MR. ROSEN: Excuse me one minute. Could you give us a copy of that backup slide?

MEMBER LEITCH: It's in here.

MR. SHENG: Okay. Now I am going to

discuss the V. C. Summer issue involving Alloy 82 and 82 welds. The first thing that people may like to ask is that, "Why do we want to attach the V. C. Summer issue into the licensing renew domains through LBB?"

The answer to that is that I can't help it because in the LBB application, there is a condition that there should not have any active degradation mechanism. And since the summer, V. C. Summer, event, we know that it may be a potential active degradation mechanism.

That's why we need to evaluate. Now let's review the V. C. Summer issue a little bit. First is that we have two findings in the primary loop of V. C. Summer.

MEMBER LEITCH: Excuse me. Could you remind me what LBB is?

MR. SHENG: LBB means leak before break.

MEMBER LEITCH: Oh, yes. Thank you.

MR. ROSEN: And what is the basis for the finding that there should not have any active degradation methods? Where did you say that was from?

MR. SHENG: That's from originally when we made the LBB application, it appeared in the SRP. It also appeared in several original documents so that there are many, many conditions that we should not apply LBB to certain piping and while these conditions should not have active degradation mechanisms.

MR. ROSEN: So I can't apply for a break to the component cooling water piping in the containment, for example?

MR. SHENG: If it turns out that the PWSCC is indeed a generic issue --

MR. ROSEN: It's external corrosion of duly sweating. It's an act of degradation, I can assume, on the component cooling water piping inside containment. We were just told that. So what you are saying is that they can't use leak before break on the containment water piping, cooling water in containment?

MR. SHENG: Probably because LBB, there are so many lines in the reactor system. And there are only several which have obtained approval from NRC for their LBB application. So it does not apply to every line.

So let's review the two findings. The first is that we have the through-wall avail flaw in Loop A. And then we have shallow axial and circumferential flaws discovered in Loops B and C. The shallow means that their depth was estimated to be less than one-eighth of an inch.

MEMBER WALLIS: Not only do we have a flow, but I think we have a leak.

MR. SHENG: That's right. That is the first scenario. We found axial flaw, through-wall axial flaw. Another thing is that we did not find anything in the cooler pipes. So we said difference of operating temperature of only 80 to 100 degrees Fahrenheit lower. And then we didn't find anything. And also the implication of this is there may be something wrong with Loop A, that hot leg only. Something may be very special about that. That's why we did not find axial flaws, through-wall axial flaws, in the other two hot legs.

VICE-CHAIRMAN BONACA: But wasn't the additional concern the one that the inspections did not identify the existence of these flaws?

MR. SHENG: So I'm going to discuss it later.

VICE-CHAIRMAN BONACA: The NRC's concerns aren't regarding the flaws alone. I think my concern is the one that we do perform inspections. They were volumetric inspections and didn't see anything. And that is my concern.

MR. SHENG: That's right. That's right.

VICE-CHAIRMAN BONACA: All license renewal depends on this adequacy of inspections. And if the inspections don't see things, then we have a problem.

MR. SHENG: Right. That is also my concern, also the NRC's concern.

VICE-CHAIRMAN BONACA: Yes, I see.

MR. SHENG: We are going to address it in a second viewgraph.

VICE-CHAIRMAN BONACA: Okay.

MR. SHENG: Okay? So basically I just say NRC's concern is that are these findings generic or plant-specific? That also answers your question because we need to have a reliable inspection tool to answer question one. Okay? So it's really tied into the question.

Now, the second thing, that is really our concern. Do deep and extensive circumferential flaws exist? If I only have axial flaw, it is really not my major concern because that is just a perfect example of leak before break.

Now let's take a look. Let's just have a digression from the generic concern to plant-specific concern and see what is the situation of V. C. Summer and North Anna. The report to us is on plant-specific information.

First, they do not have alloy 82/182 welds on either the hot leg or cold leg piping on the primary loop.

MEMBER WALLIS: What kind of welds do they have?

MR. SHENG: They just have the outstanding steel welds, not using these --

MEMBER WALLIS: And you are saying that that is somehow better than alloy 82/182?

MR. SHENG: Yes, yes.

MEMBER FORD: Is 308 weld?

MR. SHENG: I don't know. I don't know the detail of that, but I think the licensee may be able to. I can pull out this information to you.

MEMBER WALLIS: Do they have buttering of the same kind of way or not, what they actually have? I mean, you are saying it's not like Summer.

MR. SHENG: That's right.

MEMBER WALLIS: But does it have any of the features of Summer?

MR. SHENG: Mature-wise, no. But if you are talking about the welding structure and how they weld it, as I said, if you are interested in that risk factor, I can provide the information to you later. So far the --

MEMBER WALLIS: I am just wondering.

Maybe the materials people can reassure me whether 82/182 is somehow the villain or it's somehow the way in which they made the welds at V. C. Summer, which has probably contributed to what they observe there.

MR. SHENG: Yes, but right now we --

MEMBER FORD: The answer is yes.

MR. SHENG: We identify that for --

MR. SNOW: This is Tom Snow. Would you like me to comment on that? I am with Dominion, obviously.

The nozzles on the reactor vessel are carbon steel, of course, with a stainless steel safe end attached. The piping for the reactor coolant system is all stainless steel. So we are going from a stainless steel safe end to a stainless steel piping with a stainless steel weld.

MEMBER FORD: And the weld is 308?

MR. SNOW: I do not know exactly whether it is 308. I would have to check on that.

MEMBER FORD: Is there a stainless steel liner in the piping, too?

MR. SNOW: The nozzle, carbon steel nozzle, is clad with stainless steel, yes.

MEMBER LEITCH: And those comments apply to both North Anna and Surry?

MR. SNOW: Those comments do apply to both Surry and North Anna.

MEMBER LEITCH: Thank you.

MR. SHENG: Okay. So the good news is that they don't have the vulnerable welds on the primary loop, but they do have these types of welds on some other portion within the RCS system and basically I think the LBB on the reactor coolant pump weld, I think in that nozzle, the outlet nozzle, to the reactor coolant pump. So basically we still have to attack this issue, to resolve this issue, even if they don't have that type of weld on the primary loop.

Now talking about how to resolve the issue plant specifically under 10 CFR Part 50, first we have to rely on the interim conclusion from the generic investigation. And the conclusion from that is that there is no immediate safety concern. The reason is that the reason is because first the industry --

CHAIRMAN APOSTOLAKIS: So there will be a concern at some point?

MR. SHENG: Yes, there will be.

CHAIRMAN APOSTOLAKIS: When?

MR. SHENG: Let me give you some comfort about why we say there is no immediate safety concern. Then when I proceed, I will answer your question gradually.

CHAIRMAN APOSTOLAKIS: Sure.

MR. SHENG: Okay. The reason there is no immediate safety concern, first we have the industry has performed analysis because we don't know the situation. Suppose that we have equal opportunity to have axial flaw and circumferential flaw. Then how about the driving force? Which one is going to have a much, much bigger driving force?

So the industry performed a final analysis basically assimilating that the welding process layer by layer analysis and also reflecting the excessive review work, which is very special to these Loop A welds.

The result of this study shows that the stresses, the residual stresses, are much, much higher for the axial flaw. So the implication is that if you do have a flaw created somewhere, then the axial flaws tend to grow much faster.

MEMBER WALLIS: We heard all of this before with the control rod drive mechanisms.

MR. SHENG: I understand. Yes, but the situation may be a little different because --

MEMBER WALLIS: It's a bigger plant.

MR. SHENG: In addition to the industry's analysis, NRC has also contracted Batel to do a similar analysis but, of course, more extensive with a lot of assumed cases with a different, say, wording from ID and wording from OD because of the lack of information assuming we have reworded this way and that way. So we have like probably more than ten cases to be analyzed.

The Batel result is able to put down some kind of number in the conclusion, which said that the axial flaw, the growth rate for the axial flaw, is at least two times larger than the growth rate of the circumferential flaw.

So based on this analytical work, you can see that the role of these kinds of excessive reworks will play in defining the residual stresses which cause that through-wall axial flaw.

Now, this is the analytical side because usually when you have a theory, you need something to validate it, to support it. So let's now take a look at what we have seen for the V. C. Summer. The V. C. Summer only indicates a through-wall, also axial flaw.

In addition, we have two other four-ring cases, which are RINGO 3 and RINGO 4. RINGO 3, we discovered two axial flaws. In RINGO 4, they discovered four axial flaws. So you can see that the evidence that we have found so far from the industry domestically and for foreign plants, they also show axial flaws.

But, of course, in the V. C. Summer, V. C. Summer is the only plant which also shows a circumferential flaw. But they are not that extensive.

MEMBER WALLIS: So you are arguing that the axial flaws will incur first, and you will detect them before you will get any circumferential flaws?

MR. SHENG: That's right.

MEMBER WALLIS: You have to detect those axial flaws, as my colleague said over here.

MR. SHENG: That's right. That's right. I should be able to do that. I think some of the members had pointed out last time that they don't have confidence in the UT methodology right now because you learned that some flaws can be found in V. C. Summer by ET, but it cannot be verified by UT.

I just want to point out that since the discovery of the V. C. Summer issue, that the UT methodology has been improved significantly. For instance, when the second time, when V. C. Summer personnel went to investigate those four flaws, at this time they could detect two of them. So if it would be better, they could have had all four of them. But at least they now can detect two of them.

MEMBER WALLIS: These are all plausible arguments.

MR. SHENG: So it's a qualitative improvement, but the key thing is what the licensee is going to do and what the industry is going to do in their future inspections. Basically --

MR. KUO: Simon?

MR. SHENG: Yes?

MR. KUO: I'm sorry. I have to interrupt you a little bit. Let's not sidetrack the issue. We are talking about the North Anna and the Surry.

MR. SHENG: Yes. I'm going to address that now. Yes. I just say that the licensee will conduct future inspections using performance demonstration. The key component of that performance demonstration is a blind mock-up qualification per ASME Appendix VIII required by 10 CFR 50.55a.

MEMBER WALLIS: Excuse me. What does ten-year ISI program mean? Does it mean that you inspect every ten years or does it mean something else?

MR. SHENG: No. It's just that in their ISI program, they have scheduled to inspect certain piping at a certain time.

VICE-CHAIRMAN BONACA: Well, a given location would be inspected over ten years.

CHAIRMAN APOSTOLAKIS: I think Professor Wallis is right.

MEMBER WALLIS: So something could happen in that ten years that is not detected.

MR. SHENG: That's right, but remember that --

MEMBER WALLIS: So are you going to go through the old argument that flaws grow so slowly that in ten years, it's okay to wait ten years to find them?

MR. SHENG: No. It's more than that because --

MEMBER WALLIS: More than ten years?

MR. SHENG: No, no, no, no. Now we are addressing the plant-specific issues now. That's why you have these questions. Remember that we are also resolving these generically. For instance, in 2001, some plants have conducted a thorough inspection of their primary loop hiking, which is these three plants are -- let's see. I have their names here. It's McGuire I, Salem I, and Robinson II.

So basically you have V. C. Summer and

RINGO 3 and 4. We have three plants, three additional plants, which show no flaw similar to what we have --

MEMBER WALLIS: Are they younger or older than Surry and North Anna, these older plants?

MR. SHENG: You are talking about the vintage of the plants.

VICE-CHAIRMAN BONACA: And they have cracks.

MR. SHENG: Yes, they have cracks, but they have subsurface cracks.

MEMBER WALLIS: Are they older or younger than Surry and North Anna, these three plants you cited?

MR. SHENG: These three plants. Let me see. I know that Robinson is --

MR. CORBIN: This is Bill Corbin with Dominion.

Robinson is a similar vintage as Surry. Surry is the older of our plants.

MR. SHENG: And McGuire, I don't know. But, as I said, if I entirely rely on the North Anna and the Surry inspection results, it may not be enough.

Every year some other plant will turn in their inspection results for not just the primary loop welds but also some other pipings involved in 82/182 welds. Then each year I will receive probably nine or ten inspection results using much more reliable UT inspections. Then maybe at a certain time we can make a decision and say that, really, V. C. Summer is a plant-specific issue.

MR. BATEMAN: Simon, can we please move to North Anna and Surry now and stay off of Summer and all of these other plants which aren't germane to this discussion?

MR. SHENG: Sure.

MR. BATEMAN: Good. Let's start with North Anna, please.

MR. SHENG: I have already said that --

MEMBER LEITCH: Is this a true statement that North Anna and Surry have committed to use the best industry practice that is available today?

MR. SHENG: Yes.

MEMBER LEITCH: And if in the future years better practices are developed, they will use those better practices. Is that true?

MR. SHENG: Well, by definition, they use blind mock-up.

MEMBER LEITCH: That's today's practice, today's best practice.

MR. BATEMAN: Excuse me. This is Bill Bateman on the staff.

The specific practice in 50.55a was basically supposed to be achieved by the industry by November 22nd. Industry did not make that date. So we're dealing with that the present.

MR. SHENG: Yes, but the --

MR. BATEMAN: Simon, just finish up with North Anna and Surry, please.

MEMBER WALLIS: Well, when you had all of this discussion, how did you close the North Anna and Surry issue before you got on to what was supposed to be a red herring here?

MR. SHENG: Yes. As I said, we cannot close it right now.

MEMBER WALLIS: You cannot close it right now?

MR. SHENG: Right.

MEMBER WALLIS: Okay.

MR. SHENG: That's why I say that the only conclusion I acknowledge is there is no immediate safety concern. The conclusion, the interim conclusion, is that there is no immediate safety concern. So we are resolving it.

MR. BATEMAN: This is Bill Bateman.

MR. SHENG: -- receiving reliable inspection data the next few years.

MR. BATEMAN: This is Bill Bateman, NRR.

I think Simon made it clear in his presentation that there are no Alloy 82/182 welds on the hot or cold leg here. So the situation that we are talking about here, the similar metal weld inspection that Simon was referring to, really does not apply to North Anna and Surry. We've got stainless steel welds in these locations.

MR. TABATABAI: And, as you mentioned, Mr. Leitch, Dominion is committed to perform the state-of-the-art inspection program as it becomes available as industry makes progress in that regard and also they are committed with the next scheduled inspection they have to use this improved and enhanced duty inspection program. That is how the staff closed the issue of V. C. Summer in North Anna and Surry.

From the staff's point of view, the issue of V. C. Summer is closed because it does not apply to North Anna and Surry. The V. C. Summer issue is big, reviewed and evaluated by the staff generically and outside the license renewal issue.

MEMBER LEITCH: We're at a bit of a time press here. We still need to talk about erosion/corrosion.

VICE-CHAIRMAN BONACA: Let's note, however, on the other hand, there is an issue about the industry. This seems to me it has generic implications to inspections because at least I am not a collusional person, but I have always had trust that these ten-year inspections were sufficient to identify flaws.

I have a concern now because we hear that, in fact, they are not going to be able to identify flaws. So that is a real concern. I don't know to what extent it is a generic issue, but it is.

MEMBER FORD: Can I just ask one question? Which of the parts of the reactor cooling system have 82/182 in it? In your second bullet, you said --

MR. TABATABAI: No. They don't have any 82/182 at the primary system. They have others --

MR. SHENG: They have reactor coolant pump or in that nozzle. So basically they have something --

MR. AITKEN: This is Paul Aitken. The other locations we have are at our North Anna facility in our pressurizer nozzles and our steam generator nozzles, not in our reactor coolant pump locations.

MEMBER FORD: And this is a

low-temperature plant?

MR. AITKEN: Low-temperature, yes. Correct. There may be low-temperature plants at both locations. I mean, it's normal operating, 600 degrees.

MEMBER FORD: The location of those 82/182 welds, are they low-temperature or not?

MR. AITKEN: No, no, no.

MR. BATEMAN: This is Bill Bateman on the staff.

Just a little comment there. I think you may note, Dr. Ford, that North Anna II is replacing their head because of the deteriorating of the alloy 82/182 welds in those vessel head penetrations. So they are considered a high-susceptibility plant.

MR. AITKEN: But not to focus on the coolant pumps as much as just at North Anna, it's in our pressurizer and generator nozzle locations is where we have those other situations.

MEMBER SHACK: You must have instrument nozzles, too, also?

MR. AITKEN: Correct. That's correct. That's correct. Spray nozzles.

MEMBER SHACK: Steam generator?

MR. AITKEN: At North Anna.

MEMBER SHACK: At North Anna?

MR. AITKEN: And pressurizers in North Anna.

MEMBER SHACK: You replaced the steam generator at Surry. That was a 182 weld or that is a 308 weld?

MR. AITKEN: That is not a 182, but I don't know the exact material. We do know that it's not 82/182, correct.

MEMBER FORD: If someone could get back to us as to is it 308 or is it 247?

MR. SHENG: We'll get back to you on that.

MEMBER FORD: Three forty-seven would give me concern.

MR. SHENG: If there aren't any other questions in the V. C. Summer area, I am going to turn to Kristoff Parczewski, who is going to talk about the flow-accelerated program.

MR. PARCZEWSKI: My name is Kristoff Parczewski. I am a member of the Materials and Chemical Engineering Branch at NRR.

I am going to talk about the corrosion/erosion in North Anna/Surry plant. Erosion/corrosion occurs in the components made out of steel. If you have another type, it is completely immune to erosion/corrosion.

In North Anna/Surry plants, these components are located in five systems. I made a mistake. There should have been another, main steam, I missed on the slides. Those components of this system are crediting the flow facility to corrosion program.

Flow-accelerated corrosion has two aspects. One aspect is predictive. It predicts the erosion/corrosion before they produce. The second aspect is just try to reduce flow-accelerated corrosion but change the operating condition. And both are addressed by this licensee.

MEMBER WALLIS: Can I ask you about CHECKWORKS? You've got some numbers from CHECKWORKS later on.

MR. PARCZEWSKI: Yes.

MEMBER WALLIS: CHECKWORKS is not a very precise predictive tool. It's a good one.

MR. PARCZEWSKI: Yes. I am going to just mention it.

MEMBER WALLIS: Maybe when you present the numbers, you can say something about how accurate they are because you got very accurate numbers for the predicted rate of wall thinning. I just don't think

CHECKWORKS comes anywhere near giving that accuracy of predictive.

MR. PARCZEWSKI: It's probably the best in existence.

MEMBER WALLIS: That may be true, but there are lots of things that are the best in existence.

MR. PARCZEWSKI: I think from my experience, I think the predictable is fairly reliable and I think it is a very useful tool.

MEMBER WALLIS: I just want a number that says how precisely they can predict.

CHAIRMAN APOSTOLAKIS: When will these numbers be shown, next slide?

MEMBER WALLIS: Next slide, right.

CHAIRMAN APOSTOLAKIS: Okay. Let's wait until next slide.

MR. TABATABAI: Dr. Wallis, I just wanted to refresh my memory and the full Committee's memory from the subcommittee presentation we made. We wanted to reach the conclusion that the flow-accelerated corrosion program at North Anna and Surry is working. The trend is decreasing. All of these slides we are talking about is going to conclude to that, that their corrosion program is working, in fact.

MEMBER WALLIS: You're predicting that if you extrapolate the data, the rate of loss of material is negative. Never mind.

CHAIRMAN APOSTOLAKIS: Well, you didn't actually state it very well, but I know what you mean. You said that you wanted to show. I don't know why you wanted to show because there is no problem here. You only wanted to reach some conclusion. And probably that conclusion was that there is no problem.

MR. TABATABAI: Well, Dominion has put another program in place which relates to pH program. They have increased the pH program that caused flow-accelerated corrosion to work effectively. And they have replaced less piping over the years. That's basically the --

MEMBER LEITCH: Can we try to bring this discussion to a close by 4:30? I mean, we're really pressing time.

CHAIRMAN APOSTOLAKIS: Go to the slide you think is most important. Can you do that?

MEMBER WALLIS: We didn't get to the table.

CHAIRMAN APOSTOLAKIS: The important two slides that you want to use to convince the Committee that what you are saying is correct.

MR. PARCZEWSKI: All right.

CHAIRMAN APOSTOLAKIS: I am sorry to do that to you.

MR. PARCZEWSKI: That is all right. Maybe we'll start with the one which concerns the predictive part. This is the one with the numbers.

CHAIRMAN APOSTOLAKIS: Yes.

MR. PARCZEWSKI: So this is the numbers calculated by their flow-accelerated corrosion model by CHECKWORKS. Maybe it is not everything. The column on the right is the actual service time projected to 2004. The second column --

MEMBER WALLIS: That's the only thing we know really accurately perhaps.

MR. PARCZEWSKI: Yes.

CHAIRMAN APOSTOLAKIS: Give the guy a chance.

MR. PARCZEWSKI: I'm sorry. Repeat the question.

MEMBER WALLIS: No. It's okay. Go back from there into the --

MR. PARCZEWSKI: So, I mean, the number is predicted by the code, just to give you an idea of how they look like, for the components in the feedwater pipe. So this is the predictive part of the code.

CHAIRMAN APOSTOLAKIS: But isn't it true, though, that for straight pipes, the code does a poorer job than it does for 90-degree angles? Is that true? Does that show in this table?

MR. PARCZEWSKI: I'm sorry? I didn't --

CHAIRMAN APOSTOLAKIS: If I have a straight pipe, my uncertainty is higher than if I have a 90-degree or 45-degree elbow.

MR. PARCZEWSKI: Yes.

CHAIRMAN APOSTOLAKIS: Yet, the table does not say anything about it. Is that irrelevant to the conclusion that you are going to reach?

MR. PARCZEWSKI: You mean between the elbow and the straight pipe, different as you have seen, yes?

CHAIRMAN APOSTOLAKIS: The predictive line that is critical for straight pipe is 376,000 something, for 90-degree elbow is 182,000.

MR. TABATABAI: Dr. Apostolakis, the numbers, actually, if you look at the size of the column, that is a factor.

CHAIRMAN APOSTOLAKIS: That is a factor. What do you mean?

MR. TABATABAI: We are talking about the same size piping here. If you look at the numbers for straight pipe, the size is six inches. For 90 degrees, we have six inches.

MEMBER WALLIS: Well, I'm concerned about the 90-degree elbow, where the predicted time is pretty close to the actual time. I don't believe you predict average wear rate that accurately. I am not sure that "average" is the right word to use anyway.

MR. BREEDLOVE: Excuse me.

MR. PARCZEWSKI: Yes?

MR. BREEDLOVE: This is Ian Breedlove. I am with Dominion. I'm the FAC coordinator for Surry and North Anna.

The actual service time, let's look at the 90-degree elbow where the actual service time is 176,920. That is the actual service time to what we expect to be at at 2004. Since we used the model at 2004, the 182 and 18 go beyond that. They're not close at all. In other words, the predicted time to T_{crit} starts at 2004.

CHAIRMAN APOSTOLAKIS: So 182,000 hours from 2004?

MR. BREEDLOVE: Yes, sir. So we have plenty of margin in this specific case.

CHAIRMAN APOSTOLAKIS: And that margin presumably overwhelms the uncertainty in the estimation of the 182?

MR. BREEDLOVE: Yes.

CHAIRMAN APOSTOLAKIS: Do we have any evidence that that is true?

MR. BREEDLOVE: We have done many inspections on feedwater condensate at both stations. We started in '87. We have done extensive. At Surry, feedwater, we have done almost 100 percent inspections.

CHAIRMAN APOSTOLAKIS: How small do you think the 182,000 would be with some confidence?

MR. BREEDLOVE: I would be confident that I would not have to worry about that. When the number goes negative or is like 1,000 above the actual service time, that is when you want to be inspecting that component and making sure of where you are.

MEMBER FORD: I think the concern here is the accuracy. I recognize that you normalize things after each inspection. Just give the idea to the community. Where is the average wear rate, which is the average predicted wear rate presumably? You also measure the wear rate. How different would those numbers be? 4.16 mils per year. What would be --

MR. BREEDLOVE: Just go out and measure it?

MEMBER FORD: What would the wear rate be?

MR. BREEDLOVE: In some cases, the code is right on. In some cases, it under-predicts. In some cases it over-predicts.

MEMBER FORD: How much over-prediction?

MR. BREEDLOVE: It varies. CHECKWORKS isn't the heart of the system. CHECKWORKS is a tool that we use to predict. We back that up with inspections. In our case, at both stations, we have extensive inspections and will go with the one that is the most conservative as far as do we need to reinspect that component.

MEMBER WALLIS: It seems to me you are not answering the question, though. The question was, what is the uncertainty?

CHAIRMAN APOSTOLAKIS: His answer is that he is comfortable that he is handling the uncertainty, but he can't give you a number. Is that correct?

MR. BREEDLOVE: Yes, sir. The other thing to keep in mind is there are two ways to model. One is to just let it calculate and predict. The other is when you enter the wear data, it self-corrects to your actual plant conditions. So, in other words, in some cases if CHECKWORKS says your wear is twice what it should be, but it puts that on area.

MEMBER WALLIS: I'm just wondering if there is some way you can transfer your --

CHAIRMAN APOSTOLAKIS: Does the staff agree with this assessment? Are you comfortable that the uncertainties are handled reasonably well?

MR. PARCZEWSKI: Yes. To my experience, they're doing the best they could calculating with a fairly great amount of precision. It's my experience.

CHAIRMAN APOSTOLAKIS: Precision. I'm just curious. How does your experience lead to that? I mean, the code predicted certain time to, and reality confirmed that?

MR. BREEDLOVE: Can you put up the slide that shows the iron concentration, please?

MEMBER SIEBER: Well, let me ask you a very fundamental question. It seems to me that flow-accelerated corrosion occurs most rapidly in lines that are two-phase, like extraction steam.

That's where Surry had the accident, right?

MR. BREEDLOVE: No. Surry had the accident on the condensate piping, the suction to the feedwater pump.

MEMBER SIEBER: Well, in any event, extraction steam isn't listed here.

MR. BREEDLOVE: Extraction steam is included in the FAC program.

MEMBER SIEBER: Okay. It's not on the slide.

MR. BREEDLOVE: But it is included in the program.

MEMBER SIEBER: It seemed to me that from my experience, the CHECKWORKS was sort of on the conservative side. As you put in each bit of data, it ended to correct out.

MR. BREEDLOVE: Yes, sir.

MEMBER FORD: CHECKWORKS if it had been in existence and Surry had its accident, would it have predicted through-wall failure?

MR. BREEDLOVE: With the version I have now, I believe so, yes.

CHAIRMAN APOSTOLAKIS: I have to interrupt here. We're getting words that the roads are getting very, very bad. The staff is very anxious to leave. In fact, they were allowed to leave two hours ago, and they agreed to stay on our behalf. So I would ask you to summarize your conclusions in the next 17 seconds.

MR. PARCZEWSKI: Well, my conclusion is that we felt that the flow-accelerated corrosion program predicts in sufficiently accurate and conservative ways that we can assume the results are acceptable.

CHAIRMAN APOSTOLAKIS: Mr. Leitch, is there anything else?

MEMBER LEITCH: I think that concludes that. There is just one other question I had. That is, what are the proposed license conditions? Do we know at this point what they will be?

MR. TABATABAI: Mr. Weisman is here from OGC, but as far as licensing condition, we have only one issue in regards to scoping and aging management of fuse holders. Dominion has agreed to comply with what the resolution of the staff's position is regarding the cooperation of fuse holders.

MEMBER LEITCH: Okay. Thank you.

Are there any other questions from the members?

MR. ROSEN: Do you plan to go around the table and give the applicant some sense of what the members have?

CHAIRMAN APOSTOLAKIS: No, not today, not now.

MEMBER LEITCH: Mr. Chairman, back to you.

CHAIRMAN APOSTOLAKIS: Thank you, Graham. Thank you, gentlemen. Thank you very much.

We have nowhere to go. So we'll stay. We'll stay. But let me tell you what is happening. There are a few decisions we have to make regarding certain urgent matters after the break. The break will be until 4:55. But there is something really urgent right now, and I would like the members to go immediately to the separate meeting only. Please do that. And then you take a break, the staff, too, but it is really urgent for the members to go. There is a decision that needs to be made either way.

Thank you very much everybody else. Enjoy the roads.

(Whereupon, the foregoing matter went off the record at 4:35 p.m.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards 498th Meeting - OPEN SESSION

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.

/S/ Rebecca Davis

Rebecca Davis
Official Reporter
Neal R. Gross & Co., Inc.

Advisory Committee on Reactor Safeguards
498th Meeting
Plant License Renewal

Surry and North Anna Power Stations,
Units 1 and 2

December 5, 2002

Participants

- Dominion
  - ◇ Bill Corbin - Director, Nuclear Projects
  - ◇ Paul Aitken - LR Supervisor
  - ◇ Mike Henig - LR Supervisor
  - ◇ Tom Snow - LR Lead
  - ◇ John Harrell - NA&F Supervisor

Purpose of Meeting

- Provide NRC staff with an overview of the license renewal applications for Surry and North Anna Power Stations

Background

- License Renewal Applications submitted May 29, 2001
- Format consistent with NEI 95-10, Revision 3 and NUREG 1800 (SRP), Draft, August 2000
- Class of '01 not expected to use the Draft GALL report

LRA Format

- Consistent with SRP Draft, August 2000 and NEI 95-10, Revision 3
- Sections discussed today
  - ◇ Section 2: Scoping and screening methodology and results
  - ◇ Section 3: AMR results - Mechanical, Structural, Electrical
  - ◇ Section 4: Time Limited Aging Analyses
  - ◇ Appendix A: UFSAR Supplement
  - ◇ Appendix B: Aging management activities
  - ◇ Appendix C: Aging management review methodology*
  - ◇ Appendix E: Environmental Report Supplement

* Reviewers Aid - not required by SRP or NEI 95-10

Section 2:
Scoping Methodology and Results

- Used 10CFR54.4 Rule Scoping "Criteria"

  Criterion 1: safety-related

  Criterion 2: non-safety-related affecting safety-related

  Criterion 3: the five regulated events (FP, EQ, PTS, ATWS, SBO)

- Individual Tables:

Systems in Scope	Systems <u>not</u> in Scope
Structures in Scope	Structures <u>not</u> in Scope

Section 2: Screening Methodology

- Mechanical Screening Overview
  - ◇ Reviewed documentation sources to identify system intended functions.
  - ◇ Used component database in conjunction with other documentation sources to identify components supporting these functions.
  - ◇ Developed license renewal boundary drawings.

Section 2: Screening Methodology (cont.)

- Civil/Structural Screening Overview
  - ◇ Reviewed documentation sources to identify structural intended functions.
  - ◇ Used structural detail drawings to identify structural members supporting these functions.
- Electrical/I&C Screening Overview
  - ◇ Passive electrical/I&C components screened on a plant-level basis as commodities

Section 2:
Screening Results

- Screening Results Sections (Mechanical, Structural, Electrical/I&C)
  - ◇ Description
  - ◇ UFSAR Reference - hyperlink
  - ◇ License Renewal Boundary Drawings* - hyperlink
  - ◇ Components Subject to AMR - hyperlink to table

* mechanical systems only

Section 3:
Aging Management Review

- Each AMR Results Section
  - ◇ System/Component description reference
  - ◇ AMR results tables
  - ◇ Generic Topical Report applicability, applicant action item response table if applicable - N/A for structures and electrical/I&C)
  - ◇ Materials
  - ◇ Environment descriptions
  - ◇ Aging effects
  - ◇ TLAA (if applicable)
  - ◇ Aging management activities

Dominion

Section 3: AMR Results

Table 3.2-1 Engineered Safety Features Systems — Quench Spray

Component Group	Passive Function	Material Group	Environment	Aging Effects Requiring Management	Aging Management Activity
Bolting	PB	Carbon Steel and Low-alloy Steel	(E) Air	None	None Required
			(E) Borated Water Leakage	Loss of Material	Boric Acid Corrosion Surveillance
					General Condition Monitoring Activities
Filters/Strainers	PB,FLT	Stainless Steel	(E) Air	None	None Required
			(I) Treated Water	Loss of Material	Chemistry Control Program for Primary Systems
Flow Elements	PB,RF	Stainless Steel	(E) Air	None	None Required
			(I) Treated Water	Loss of Material	Chemistry Control Program for Primary Systems
Instrument Valve Assemblies	PB	Stainless Steel	(E) Air	None	None Required
			(I) Treated Water	Loss of Material	Chemistry Control Program for Primary Systems
Instrument Valve Assemblies	PB	Stainless Steel	(E) Atmosphere / Weather	Loss of Material	General Condition Monitoring Activities
			(I) Treated Water	Loss of Material	Chemistry Control Program for Primary Systems
Nozzles	SP	Brass	(E) Air	None	None Required
			(I) Air	None	None Required
Pipe	PB	Stainless Steel	(E) Air	None	None Required
			(I) Air	None	None Required
Pipe	PB	Stainless Steel	(E) Air[1]	Loss of Material	General Condition Monitoring Activities
			(I) Treated Water	Loss of Material	Chemistry Control Program for Primary Systems

Section 4:
Time-Limited Aging Analyses Results

- Generic TLAAs
  - ◇ Reactor vessel neutron embrittlement
  - ◇ Metal Fatigue (including EAF)
  - ◇ Environmental Qualification (EQ)
  - ◇ Containment tendon prestresses (not applicable)
  - ◇ Containment liner plate and penetration fatigue

Section 4:
Time-Limited Aging Analyses Results (cont.)

- Plant-specific TLAAs
  - ◇ Crane load cycle limit
  - ◇ RCP flywheel
  - ◇ Leak-before-break
  - ◇ Spent fuel pool liner
  - ◇ Piping subsurface indications
  - ◇ RCP - Code Case N-481

Appendix A: UFSAR Supplement

- This section provides summaries of the programs and activities credited for managing the effects of aging. Each aging management program or activity accomplishes one or more of the four functions, as listed in the Standard Review Plan for License Renewal: Prevention, Mitigation, Condition Monitoring, and Performance Monitoring.

Appendix B: Aging Management Activities

- Existing Activities - 19
  - ◇ Chemistry Control, ISI, Boric Acid Corrosion...
- New Activities - 4
  - ◇ Buried Pipe and Valve Inspections
  - ◇ Infrequently Accessed Areas Inspections
  - ◇ Tank Inspections
  - ◇ Cable Monitoring (added after submittal)

Appendix B: Aging Management Activities (cont.)

- Operating Experience
  - ◇ Industry and in-house operating experience has been incorporated into aging management activities through the corrective action process
  - ◇ Operating experience reviews were performed to identify specific aging issues that apply to structures, systems and components

Aging Management Review Methodology - Appendix C

- Not required - Reviewers Aid - Explains:
  - ◇ Grouping of systems, structures, and major components - consistent with SRP and NEI 95-10
  - ◇ Short-lived components and consumables
  - ◇ Aging effects and mechanisms evaluated

Appendix E: Environmental Report

- Environmental Report and Review Process:
  - ◇ Environmental Review performed IAW NEPA
  - ◇ Environmental Impacts evaluated IAW NUREG-1437 GEIS ('96, '99)
  - ◇ Severe Accident Mitigation Alternatives (SAMAs) were reviewed and results incorporated
- Environmental Report Results:
  - ◇ Environmental Impacts are Small and Smaller Than Reasonable Alternatives

Closing Remarks

The effects of aging associated with Surry and North Anna will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation.

FRAMATOME-ANP RLBLOCA METHODOLGY STAFF SER

RALPH R. LANDRY
REACTOR SYSTEMS BRANCH, NRR
DECEMBER 5, 2002

FRAMATOME-ANP RLBLOCA

STAFF SER

- MILESTONES IN REVIEW
- REVIEW TEAM
- REVIEW RESULTS
- CONCLUSIONS

FRAMATOME-ANP RLBLOCA

STAFF SER
MILESTONES

- RECEIPT OF CODE AND DOCUMENTATION AUGUST 2001
- ACCEPTANCE FOR REVIEW OCTOBER 2001
- INITIAL PRESENTATION TO T/H SUBCOMMITTEE JANUARY 2002
- REQUESTS FOR ADDITIONAL INFORMATION JULY 2002
- DRAFT SER PRESENTED TO T/H SUBCOMMITTEE NOVEMBER 14, 2002

FRAMATOME-ANP RLBLOCA

STAFF SER
SER STRUCTURE

- SER FORMAT FOLLOWS CSAU STEPS
- OVERVIEW OF PIRT STRUCTURE
- OVERVIEW OF THERMAL-HYDRAULIC PHENOMENA MODELING
- OVERVIEW OF SELECTED ASSESSMENTS
- OVERVIEW OF CODING EXAMINATION
- OVERVIEW OF STAFF PARAMETRIC STUDIES
- OVERVIEW OF UNCERTAINTY METHODOLOGY
- CONCLUSIONS OF STAFF REVIEW

FRAMATOME-ANP RLBLOCA

STAFF SER
OVERVIEW

- PIRT REPRESENTS PHENOMENA BY TRANSIENT PHASES
- FROZEN CODE VERSION
- HEAT TRANSFER MODELLING EVALUATED - DISAGREEMENT OVER FORSLUND-ROHSENOW USE
- DECAY HEAT USES ANSI/ANS-5.1-1979

5

FRAMATOME-ANP RLBLOCA

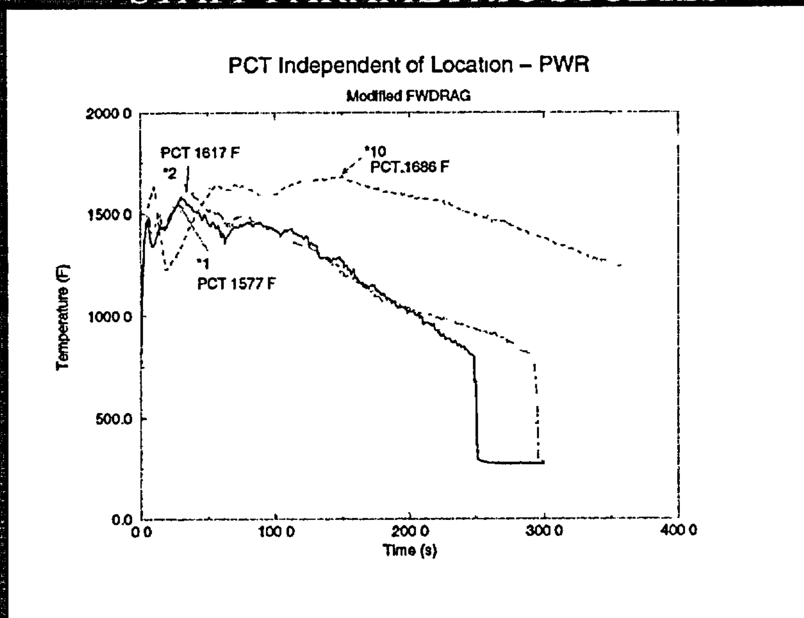
STAFF SER
OVERVIEW

- ASSESSMENT MATRIX INCLUDES SEPARATE EFFECTS AND INTEGRAL TESTS
- USED LATEST TEST PROGRAM - 2D/3D
- STAFF DID SPOT CHECKING OF CODING
- STAFF RAN NUMEROUS PARAMETRIC STUDIES
- UNCERTAINTY METHODOLOGY USES NON-PARAMETRIC ORDER STATISTICS
- BREAK TYPE AND SIZE TREATED STATISTICALLY

6

FRAMATOME-ANP RLBLOCA

STAFF SER
STAFF PARAMETRIC STUDIES



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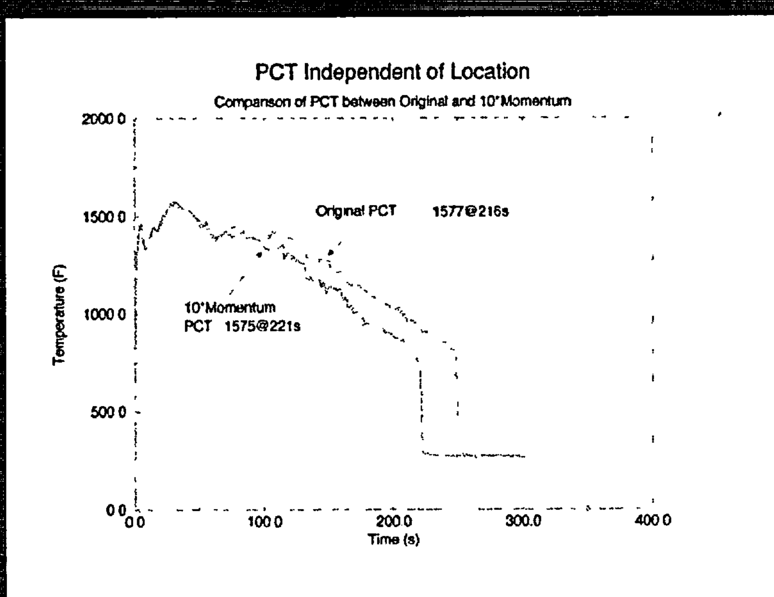
FRAMATOME-ANP RLBLOCA

STAFF SER
STAFF PARAMETRIC STUDIES



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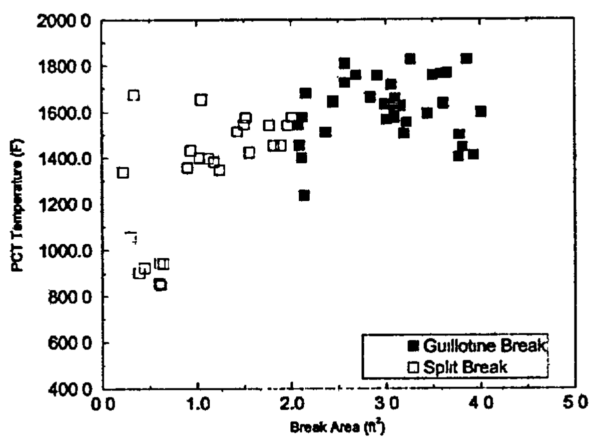
FRAMATOME-ANP RLBLOCA

STAFF SER
STATISTICAL TREATMENT OF BREAK SIZE



PCT vs. Break Size Scatterplot from 59 Calculations

9

FRAMATOME-ANP RLBLOCA

STAFF SER
CONCLUSIONS

- THE STAFF CONCLUDES FROM REVIEW OF THE DOCUMENTATION SUBMITTED BY FRAMATOME-ANP THAT THE S-RELAP5 RLBLOCA METHODOLOGY IS STRUCTURED CONSISTENT WITH THE GUIDELINES OF THE CSAU METHODOLOGICAL PROCESS AND ADDRESSES THE LICENSING REQUIREMENTS FOR A VARIETY OF SIMILARLY DESIGNED NUCLEAR POWER PLANTS
- APPLICABLE TO 3- AND 4-LOOP WESTINGHOUSE AND CE DESIGNS
- APPLIES TO BOTTOM REFLOOD ONLY
- DOES NOT DETERMINE LONG TERM COOLABILITY

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Davis-Besse Reactor Vessel Head Damage

NRC UPDATE

November 2002

This is the third periodic update on the NRC response to the reactor vessel head damage at the Davis-Besse Nuclear Power Station. The updates will be available at public meetings of the NRC Davis-Besse Oversight Panel which is coordinating the agency's activities related to the damage. Each update will include background information to assist the reader in understanding issues associated with the corrosion damage.

Findings of Completed NRC Inspections

These inspections have been completed, and the reports are in preparation. When issued, the reports will be posted on the NRC's web site at: http://www.nrc.gov - select "Davis-Besse" from the list of key issues.

- ***Containment Extent of Condition Inspection***, Part 2, found that plant personnel were properly trained and qualified to identify components and systems inside the containment building that could be affected by boric acid deposits and corrosion. They used adequate tools and followed adequate quality standards and guidance.

  Before the NRC closes this issue, however, FirstEnergy has to complete their analysis of some unresolved items, such as corrective actions for boric acid corrosion of the electrical conduit and the containment air coolers and resolution of the origin of the corrosion staining found on the bottom of the reactor vessel.

  During the first part of the inspection, conducted in September, NRC inspectors found that, in some instances, plant personnel performing these inspections weren't properly trained and certified and found weaknesses in equipment used and quality assurance procedures. After FirstEnergy addressed these problems, NRC inspectors reviewed inspection methods, observed plant personnel performing inspections, and conducted independent examinations of components in containment.

- ***Reactor Vessel Head Replacement Inspection*** found that the old reactor vessel head was safely removed from the containment and stored; the procedures and methods used to open the containment

Ongoing NRC Inspections:

1. ***Management and Human Performance Inspection*** is evaluating FirstEnergy's root cause analysis associated with management, organizational effectiveness and human performance factors that are believed to have led to the degradation of the reactor head. The inspection is also focusing on the licensee's efforts towards creating a more safety-focused environment.

2. ***The Program Effectiveness Inspection*** is reviewing the plant's progress in creating more effective programs for such areas as corrective actions, boric acid corrosion control, modification control and others.

3. ***The two NRC resident inspectors*** continue their inspections of day-to-day activities at the Davis-Besse plant as well as supporting the specific inspections underway.

The NRC Lessons Learned Task Force will present its findings and receive comments in a public meeting at 7 p.m., Wednesday, November 20, in the Auditorium of the Oak Harbor High School.

and close it after the new head was moved into containment were adequate; and plant management used appropriate methods to ensure high quality of work being performed. As part of this inspection, the NRC also reviewed the technical part of Davis-Besse's root cause report for the boric acid corrosion of the reactor vessel head and found that the plant's analysis represented an acceptable scenario for the degradation.

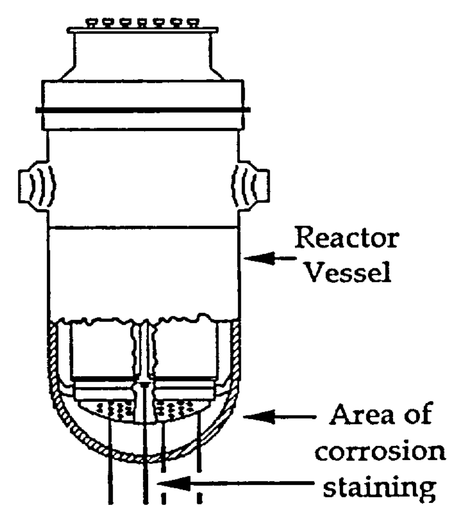
The inspection determined that the replacement head meets the applicable American Society of Mechanical Engineers codes. Inspectors reviewed the material and welds on the head and found that it was an acceptable replacement.

- ***Systems Health Inspection*** is reviewing the plant's assessment of important safety systems. NRC inspectors reviewed FirstEnergy's program for evaluating safety system health, observed and evaluated the implementation of the program by plant personnel, and conducted independent inspections of plant systems. The results of this inspection showed that the licensee's systems health program was effective and that the licensee had identified a significant number of problems requiring resolution.

  NRC inspectors also conducted a design review of three plant systems and found substantive issues requiring further review by FirstEnergy. As a result, the licensee has initiated a "collective significance" review of the NRC's findings and the plant's own inspection results in the system health area to formulate an appropriate plan of action.

- ***The Resident Inspectors' Report 02-10,*** issued October 30, documents inspections of activities such as adverse weather preparation, equipment alignment, plant modifications, and maintenance risk assessment. The findings included one low-level violation for an inadequate procedure dealing with scaffolding placement and several observations regarding implementation of the Return to Service Plan.

Results of Bottom Nozzle Tests Are Inconclusive



FirstEnergy identified rust stains on the bottom of the reactor vessel earlier this year. The stains became visible in June when plant workers removed the insulation from the reactor vessel in order to examine its condition. The licensee believes the stains probably resulted from previous cleaning of the reactor vessel head. A less likely possibility was that the stains resulted from leakage from the penetrations for incore monitoring tubes. There has been no history of such leakage in other U.S. pressurized water reactors. There are 52 tubes, each less than one inch in diameter, which contain incore monitoring devices used to measure conditions in the reactor.

The utility's consultant, Framatome, compared the chemical composition of the corrosion on the top of the reactor vessel head to the stains on the bottom. The testing showed some variation between chemical composition of corrosion products from the top of the reactor and stains on the bottom. The analyses, however, did not provide a conclusive link to the upper vessel head cleaning, nor did they show evidence of leakage from the incore tube penetrations.

Davis-Besse is reviewing its options for definitive testing of the bottom nozzles for leaks. The NRC will review the utility's testing and inspection plans and monitor the tests. The issue will be resolved prior to the NRC considering whether the plant can restart.

NRC Denies Petition For Independent Review

On October 15, the NRC denied a petition, submitted by several public interest groups under Section 2.206 of the agency's regulations. The groups sought an independent third-party review of all reactor head issues at Davis-Besse. The petition was denied because such a review would unnecessarily duplicate the agency's activities. The NRC is addressing the technical and human performance problems at Davis-Besse raised in the petition through its Oversight Panel activities. Issues regarding the agency's regulatory performance were addressed by the Lessons Learned Task Force. The task force report and recommendations are currently under review by a special management review team which will formulate proposed actions by the agency.

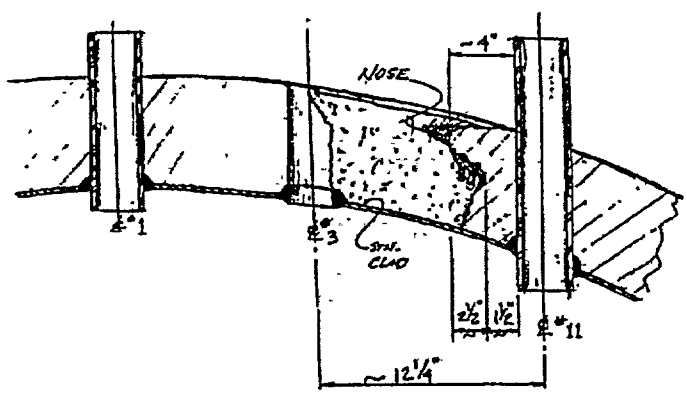
The denial decision and the petition are available for review on the NRC's web site at: http://www.nrc.gov - select "Davis-Besse" under key issues and then select "controlled correspondence."

Sump Screen Improvement

The NRC is reviewing a FirstEnergy initiative to increase the area of the sump strainers in the reactor containment at Davis-Besse. The sump is a collection point for water that would be recirculated for reactor cooling in the event of a loss-of-coolant accident. This sump modification, which was not required by the NRC, has been initiated by FirstEnergy to ensure that the strainers do not get clogged by debris which might collect at the bottom of the containment. The additional surface area of the sump strainers will provide a substantial improvement in the plant's design safety margin.

Background: What Happened at Davis-Besse

In March 2002 plant workers discovered a cavity in the head or top of the reactor vessel while they were repairing control rod tubes which pass through the head.



Sketch provided to NRC by FirstEnergy

The tubes, which pass through the reactor vessel head, are called control rod drive mechanism nozzles. Cracks were detected in 5 of the 69 nozzles. In three of those nozzles, the cracks were all the way through the nozzle, allowing leakage of reactor cooling water, which contains boric acid.

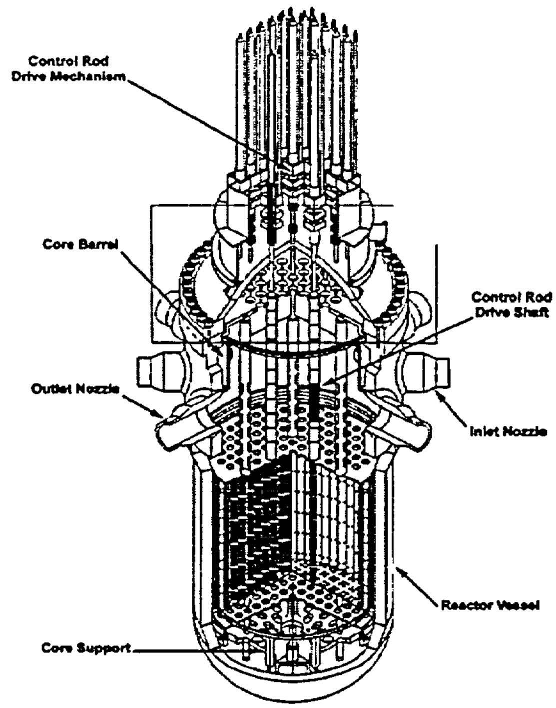
Corrosion, caused by the boric acid, damaged the vessel head next to Nozzle No. 3, creating an irregular cavity about 4 inches by 5 inches and approximately 6 inches deep. The cavity penetrated the carbon steel portion of the vessel head, leaving only the stainless steel lining. The liner thickness varies somewhat with a minimum design thickness of 1/8 inch. Subsequent examination by Framatome, FirstEnergy's contractor, found evidence of a series of cracks in the liner, none of which was entirely through the liner wall.

Earlier indications of the problem: Through-Wall Cracking of Nozzles in France and at the Oconee Nuclear Power Station in South Carolina

In the early 1990's control rod drive mechanism nozzle cracking was discovered at a nuclear plant in France. These cracks penetrated the nozzle wall along the length of the nozzle (referred to as 'axial' cracking). In 1997 the NRC issued Generic Letter 97-01 to gather information on the inspection activities for possible cracking in the control rod drive mechanism nozzles in plants in the United States. Subsequently, through-wall circumferential cracks -- around the nozzle wall -- were discovered in two control rod drive mechanism nozzles at the Oconee Nuclear Power Station, Unit 3, in 2001. While axial cracking had been found at several other plants and repaired, circumferential cracking had not been seen before. Circumferential cracking is more significant because it could lead to complete separation of the nozzle and a resulting loss-of-coolant accident.

After the Oconee discovery, the NRC issued Bulletin 2001-01, requiring all pressurized water reactor (PWR) operators to report to the NRC on structural integrity of the nozzles, including the extent of any nozzle cracking and leakage and their plans to ensure that future inspections would guarantee structural integrity of the reactor vessel boundary. The NRC's Bulletin instructed nuclear power plants with similar operating history to Oconee Unit 3, including Davis-Besse, to inspect their reactor vessel head penetrations by December 31, 2001, or to provide a basis for concluding that there were no cracked and leaking nozzles.

Typical Pressurized Water Reactor



FirstEnergy Nuclear Operating Company requested an extension of the inspection deadline until its refueling outage beginning March 30, 2002, and provided the technical basis for its request. The NRC did not allow the plant to operate until March 30, but agreed to permit operation until February 16, provided that compensatory measures were taken to minimize possible crack growth during the time of operation. The NRC was unaware that nozzle leakage or corrosion had occurred at Davis-Besse when it agreed to the February 16 date.

Boric Acid Corrosion Control Procedure

The water that circulates through a pressurized water reactor to cool the nuclear fuel contains a low concentration of boric acid. This borated water can potentially leak through flanges, pump and valve seals, and other parts of the reactor cooling system and cause corrosion.

The NRC has taken steps to make sure that PWR operators are aware of and pay attention to the corrosion boric acid can cause in certain environments:

- In 1986-89, the NRC issued a series of documents, called "generic communications," informing PWR licensees that boric acid can corrode and damage steel reactor components.

- The NRC's Generic Letter 88-05 requested PWR operators to implement a program to ensure that boric accid corrosion does not lead to degradation of the reactor cooling system components. All nuclear power plants with PWRs, including Davis-Besse, reported to NRC that the Boric Acid Control Procedures had been established and would be implemented.

Barriers Built into Nuclear Plants to Protect Public Health and Safety

The design of every nuclear power plant includes a system of three barriers which separate the highly radioactive reactor fuel from the public and the environment. The Davis-Besse reactor head damage represented a significant reduction in the safety margin of one of these barriers, the reactor coolant system. The reactor coolant system, however, remained intact, as well as the other two barriers, the fuel and the containment.

1. <u>Fuel Pellets and Rods</u>

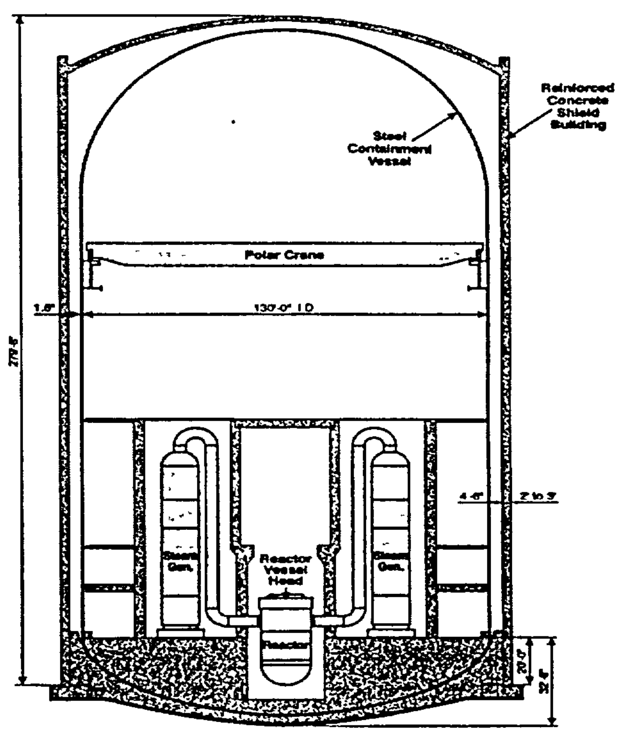
The first barrier is the fuel itself. The fuel consists of strong, temperature-resistant ceramic pellets made of uranium-oxide. The pellets are about the size of a little finger-tip. They retain almost all of the highly radioactive products of the fission process within their structure.

The pellets are stacked in a rod made of a zirconium alloy. At Davis-Besse, each fuel rod is about 13 feet long. The rods are assembled into bundles, with each assembly containing 208 rods. The reactor core contains 177 fuel assemblies. Any fission products which escape from the pellets are captured inside the cladding of the rod, which is designed to be leak-tight. Small pin hole leaks do occasionally occur, however, and the operating license requires leakage monitoring and contains limits on the maximum allowable leakage of radioactive materials from the fuel rods.

2. Reactor Coolant System

The second barrier is the reactor coolant system pressure boundary. The reactor core is contained inside the reactor pressure vessel, which is a large steel container. Thick steel pipes supply cooling water to the reactor and carry away the heated water after it passes through the reactor core. The pressure vessel, the connected piping, and other connected components make up the reactor coolant system pressure boundary. At Davis-Besse, the reactor coolant system contains about 60,000 gallons of cooling water, circulated by four large pumps at a rate of about 360,000 gallons per minute.

Simplified View of Containment Building Interior



This system is designed to be leak-tight at operating conditions which include a water temperature of 605° F and a water pressure of 2,150 pounds per square inch. The operating license contains limits on the maximum allowable amount of leakage from the system, and it specifies requirements for monitoring any leakage. If a leak is identified as being through any solid wall of the system (reactor vessel, cooling pipes or other components) continued operation of the plant is prohibited, no matter how small the leak rate.

3. Containment Building

The third barrier is the containment building. This is a large cylindrical building which contains the entire reactor coolant system. None of the piping that contains the high-temperature and high-pressure reactor coolant water extends outside the containment building. The containment is a 1 1/2 inch thick steel cylinder, rounded at the top and bottom, which is designed to be leak-tight. This steel structure is surrounded by a reinforced concrete shield building, which is the round building visible from the outside of the plant. Its walls are 2 to 3 feet thick.

NRC's Response to Vessel Head Damage

The NRC responded to the vessel head degradation with a series of actions, some specific to Davis-Besse and others aimed at other PWR plants. The agency began a review of its regulatory activities as well.

Davis-Besse

On March 12, 2002, the NRC initiated an Augmented Inspection Team to examine conditions that led to the head degradation and on March 13, 2002, the NRC issued a Confirmatory Action Letter to Davis-Besse documenting a number of actions the plant needed to implement for the unit to be allowed to restart. On April 29, 2002, the NRC established an Oversight Panel under the Agency's Manual Chapter 0350, to coordinate and oversee NRC activities necessary to address repairs and performance deficiencies at the plant in order to guarantee that it can operate safely. The plant will not restart until the NRC is satisfied that plant operators have met all necessary safety requirements.

Generic

On March 18, 2002, the NRC issued Bulletin 2002-01, instructing PWR licensees to report on the condition of their head, past incidents of boric acid leakage and the basis for concluding that their boric acid inspection programs were effective. All plants sent their responses and indicated that no evidence of extensive corrosion of reactor vessel heads was found at these plants. On August 9, 2002, the NRC issued Bulletin 2002-02 advising PWR operators that more stringent inspection techniques may be necessary to detect head penetration nozzle cracks. Visual examination of reactor vessel heads and nozzles may need to be supplemented with other inspection techniques, such as the use of ultrasound, electric currents and liquid dyes. In October, the agency also requested PWR licensees to provide additional information on their boric acid inspection program with greater detail than initially covered in the responses to Bulletin 2002-01.

NRC Davis-Besse Oversight Panel

An NRC Davis-Besse Oversight Panel was created to make sure that all corrective actions, required to ensure that Davis-Besse can operate safely, are taken before the plant is permitted to restart and that Davis-Besse maintains high safety and security standards if it resumes operations. Should the plant restart, the Oversight Panel will evaluate if Davis-Besse's performance warrants reduction of the NRC's heightened oversight and, if so, recommend to NRC management that the plant return to a regular inspection schedule. The panel was established under the agency's Manual Chapter 0350.

The panel brings together NRC management personnel and staff from the Region III office in Lisle, Illinois, the NRC Headquarters office in Rockville, Maryland and the NRC Resident Inspector Office at the Davis-Besse site. The eight-member panel's chair and co-chair are John Grobe, a senior manager from Region III and William Dean, a senior manager from NRC headquarters.

As part of determining if plant corrective actions are adequate to support restart, the Oversight Panel will evaluate FirstEnergy's return to service plan, which is divided into seven areas of performance that the utility calls "building blocks." A series of NRC inspections are being performed to verify the company is taking proper actions in each of the seven areas. These reviews will include the work by the FirstEnergy staff and, in addition, the NRC staff will perform independent inspections in each of the "building block" areas.

Issues to be resolved in order for Davis-Besse to restart

The NRC Oversight Panel will only consider recommending that Davis-Besse resume operations when the plant has demonstrated its readiness to operate safely. Key elements will include:

- Davis-Besse management and personnel properly understand the technical, organizational, programmatic and human performance problems that led to the extensive degradation of the plant's reactor vessel head.
- Davis-Besse enhances programs for operating the plant safely, detecting and correcting problems, controlling boric acid corrosion, and is fostering a more safety-conscious environment among plant managers and workers.
- Davis-Besse improves the performance standards of its managers and workers, including their "ownership" of the quality of work products and the safety focus of decision-making.
- The replacement of the vessel head is technically sound and all reactor components are inspected, repaired as necessary, and demonstrated to be ready for safe operation.
- Plant safety systems inside and outside containment are inspected, repaired as necessary, and have been confirmed to be ready to resume safe operation of the plant.

- Plant operators demonstrate appropriate safety focus and readiness to restart the plant.
- Any organizational or human performance issues resulting from the ongoing investigation conducted by the NRC's Office of Investigations are addressed.
- All licensing issues that have arisen as a result of the reactor head replacement have been resolved.
- Resolution of radiation protection issues associated with the radiation exposure to workers during steam generator work and the particle contamination found in offsite locations.
- Modification of the strainer system for the containment sump, which would be the source of cooling water for recirculation in the event of a loss-of-coolant accident.

What Happens If the Plant is Allowed to Restart

If the facility is permitted to restart, the NRC Oversight Panel will continue to monitor plant activities and operations until panel members are confident that the root cause(s) of the problem have not recurred. Should FirstEnergy achieve that performance level, the NRC Oversight Panel would recommend to NRC management that responsibility for the plant oversight be transferred back to the Region III line organization for monitoring under the Reactor Oversight Process. The panel would then cease to exist. Should FirstEnergy not demonstrate sustained improved performance, the panel will recommend appropriate regulatory actions.

Public Participation in the Process

The NRC's experience is that members of the public, including public officials and citizens, often raise questions or provide insights that are important to consider. If you have questions or want to provide information or a point of view, please contact us. For feedback on this newsletter, contact Viktoria Mitlyng 630/829-9662 or Jan Strasma 630/829-9663 (toll free 800/522-3025 - ext -9662 or -9663). E-mail: opa3@nrc.gov. Extensive information about the Davis-Besse reactor vessel head damage and the ensuing activities is available on the NRC web site: http://www.nrc.gov - select "Davis-Besse" under the list of key topics.

Briefing for the
Advisory Committee on Reactor Safeguards
December 5, 2002

Update on USNRC Oversight of the Davis-Besse Nuclear Power Station

Jack Grobe, Chairman
Davis-Besse Oversight Panel

Previous Briefings of The Committee

- **April 9 and 11, 2002**
  - Presented the NRC's Augmented Inspection Team results
- **June 5 and 6, 2002**
  - Described the charter and membership for the NRC's Davis-Besse Oversight Panel
  - Summarized FirstEnergy's return to service plan

Objectives of this Briefing

- Update on activities of the NRC's Davis-Besse Oversight Panel

- Summarize the results of recent inspection activites

- Describe several significant plant equipment issues

Restart Checklist

- Issued August 16 and updated October 30, 2002

- Identifies significant issues requiring action before restart

Restart Checklist

- ## Key Areas for Review

1. Adequacy of root cause determination
2. Adequacy of safety significant structures, systems and components
3. Adequacy of safety significant programs
4. Adequacy of organizational effectiveness and human performance
5. Readiness for restart
6. Licensing issue resolution
7. Confirmatory Action Letter resolution

Restart Checklist

1. Adequacy of Root Cause Determination

- Penetration cracking and reactor pressure vessel corrosion
- Organizational, programmatic and human performance issues

Restart Checklist

2. Adequacy of Safety Significant Structures Systems and Components

- Reactor pressure vessel head replacement
- Containment vessel restoration
- Structures, systems and components inside containment
- Emergency core cooling system and containment spray system sump
- Systems outside containment

Restart Checklist

3. Adequacy of Safety Significant Programs

- Corrective action program
- Operating experience program
- Quality audits and self-assessments of programs
- Boric acid corrosion management program
- Reactor coolant system unidentified leakage monitoring program
- In-service inspection program
- Modification control program
- Radiation protection program

Restart Checklist

4. Adequacy of Organizational Effectiveness and Human Performance

- Adequacy of root causes
- Adequacy of corrective actions
- Effectiveness of corrective actions

Restart Checklist

5. Readiness for Restart

- Systems readiness for restart
- Operations readiness for restart
- Test program development and implementation

Restart Checklist

6. & 7. Licensing Issue and Confirmatory Action Letter Resolution

- Resolve three limited ASME code relief requests

- Meet with the NRC to obtain restart approval

Inspection Accomplishments

- ## Completed and Ongoing Inspections

1. Augmented inspection team follow-up
2. Reactor vessel head replacement
3. Containment health assurance/boric acid extent of condition
4. System health assurance
5. Program effectiveness
6. Organizational effectiveness and human performance

Inspection Accomplishments

1. Augmented Inspection Team Follow-up Findings

- Violation of pressure boundary leakage requirements (Technical Specification)
- Failure to take corrective actions (10CFR50, Appendix B, Criterion XVI)
  - Boric acid buildup on reactor head
  - Boric acid accumulation on containment air coolers
  - Contaminant clogging of radiation element filters
  - Installation of service structure access modification for inspection and cleaning
  - Adverse trend in reactor coolant system unidentified leakage

Inspection Accomplishments

1. Augmented Inspection Team Follow-up Findings (Continued)

- Failure to have adequate boric acid corrosion control procedures (10CFR50, Appendix B, Criterion V)

- Failure to follow boric acid corrosion control and corrective action procedures (10CFR50, Appendix B, Criterion V)

- Failure to provide complete and accurate information (10CFR50.9)

Inspection Accomplishments

2. Reactor Vessel Head Replacement

- Results
  - Replacement head meets ASME Section III N-stamp requirements
  - Replacement head non-destructive examination adequate (several code relief requests under review)
- Outstanding issues
  - Reactor coolant system pressure test
  - Containment integrated leak test

Inspection Accomplishments

3. Containment Health Assurance/Boric Acid Extent of Condition

- Results
  - Evaluation of structures systems and components adequate
  - Repair and refurbishment activities ongoing
- Outstanding issues
  - Reactor pressure vessel bottom head integrity
  - Environmentally qualified splice maintenance concern
  - Electrical conduit corrosion ground path concern

Inspection Accomplishments

4. System Health Assurance Inspection

- Results
  - Davis-Besse review process adequate
  - Davis-Besse design and operational review identified several issues
  - NRC design review identified several issues
  - Davis-Besse evaluating need for scope expansion
- Inspection approximately 50% complete

Inspection Accomplishments

5. Program Effectiveness Inspection

- Results
  - Davis-Besse review process adequate
  - Review of boric acid corrosion management and corrective action program adequate
- Inspection approximately 25% complete

Inspection Accomplishments

6. Organizational Effectiveness and Human Performance Inspection

- Results
  - Davis-Besse completing root cause assessments
  - Corrective actions initiated for identified causes adequate
  - Safety culture and safety conscious work environment corrective actions initiated
- Inspection approximately 25% complete

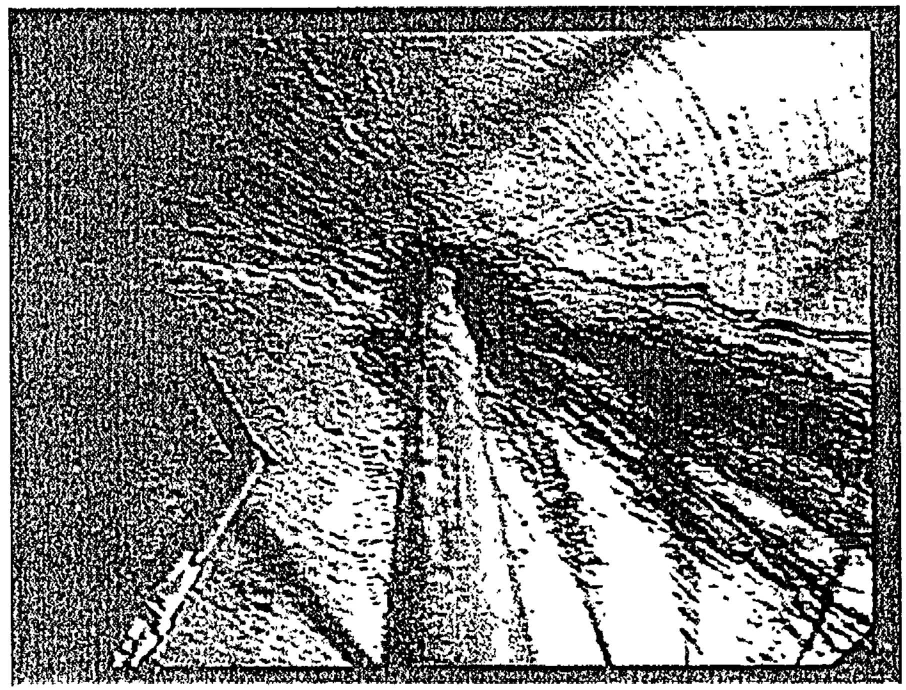
Plant Equipment Issues

1. Reactor Pressure Vessel Bottom Head
2. Containment Sump
3. Decay Heat Valve Pit
4. Coatings Inside Containment

Plant Equipment Issues

1. Reactor Pressure Vessel Bottom Head

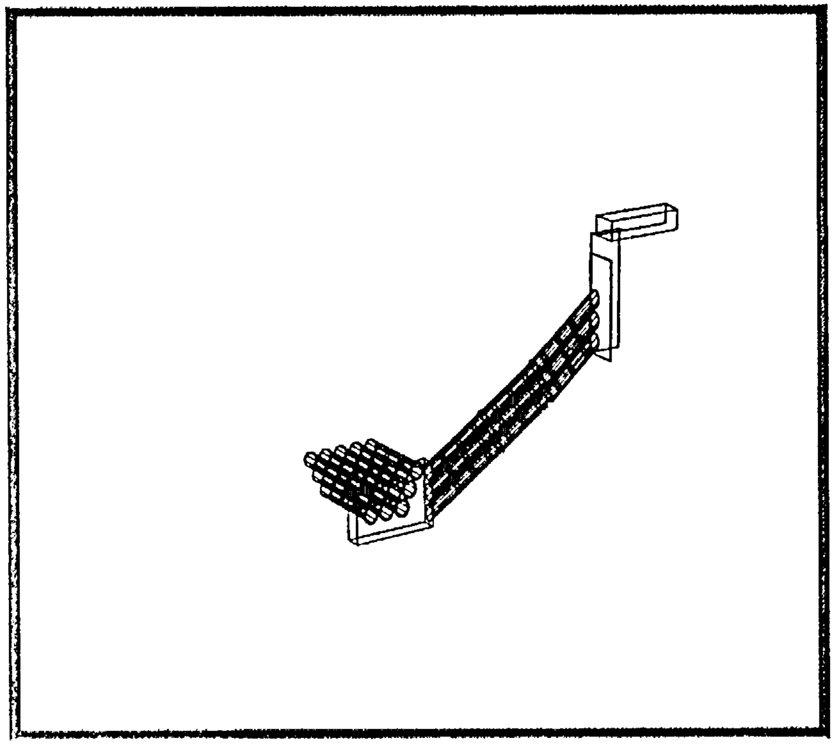
- Accumulations on bottom head in-core detector nozzles
- Chemical analysis not conclusive
- FirstEnergy planning a leakage test at normal operating temperature and pressure



Plant Equipment Issues

2. Containment Sump

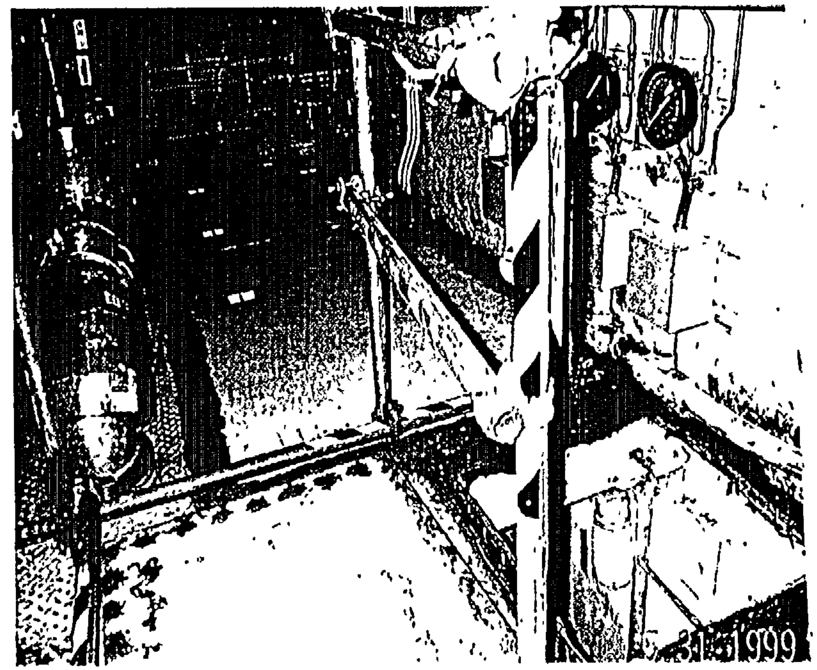
- As found condition
  - Screen mesh size
  - Gaps
  - Non-permanent modifications
  - Approximately 50 square foot screen
- Modification to increase screen area to approximately 1,200 square feet



Plant Equipment Issues

3. Decay Heat Valve Pit

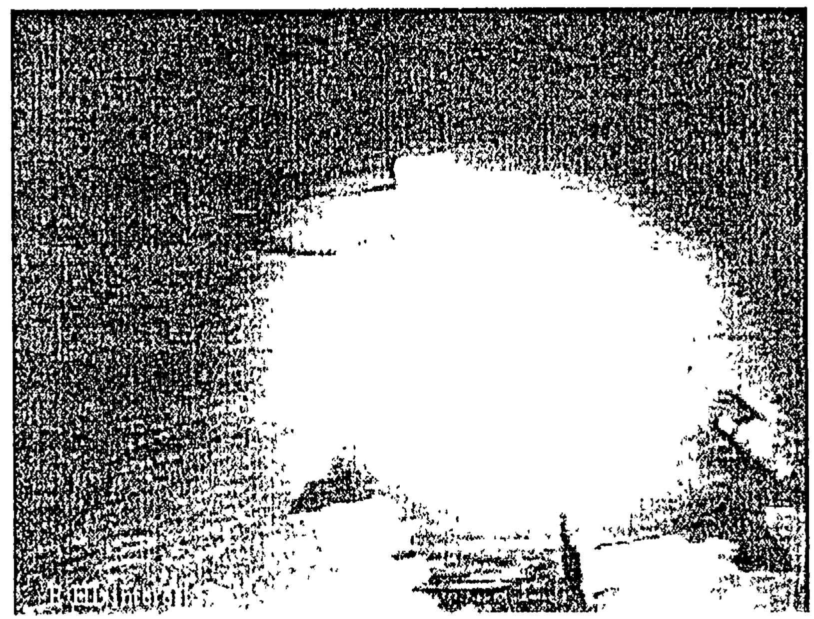
- As-found condition
  - Valve operators not qualified for submersion
  - Plate closure sealing challenge
  - As-left and as-found testing
- Modification to enclose and properly seal valve pit



Plant Equipment Issues

4. Coatings Inside Containment

- Containment walls and dome
- Conduit
- Core flood tanks and reactor pressure vessel



Conclusions

- USNRC oversight activities well organized and focused
- FirstEnergy's restart reviews ongoing
- FirstEnergy's actions appear adequate and safety focused
- USNRC activities fulfilling Performance Goals

United States Nuclear Regulatory Commission

Davis-Besse Reactor Vessel Head Degradation
Lessons-Learned Task Force

Briefing for ACRS
December 5, 2002

Overview

Background

- NRC has taken the initiative to conduct lessons-learned reviews for significant issues
  - Self-critical
  - Improvements made
  - Examples:
    - Indian Point 2 steam generator tube failure (2000)
    - NRC inspections at the South Texas Project (1995)

Overview

Objectives and Scope

- Perform independent evaluation
- Review:
  - Reactor oversight process
  - Regulatory processes
  - Research activities
  - International practices
  - Generic Issues program
- Identify and recommend improvements

Overview

Composition and Attributes

- Multi-disciplined, experienced team
- No previous significant involvement in Davis-Besse Nuclear Power Station (DBNPS) oversight
- Observation by State of Ohio
- Stakeholder input to task force review activities
  - Solicited input at two public meetings

Overview

Review Methods

- Comprised of two groups
- Performed document reviews and conducted interviews
- Conducted fact finding at DBNPS site
- Conducted reviews at NRC Regional Offices and Headquarters

Overview

Report

- The report is available on ADAMS (the NRC electronic document management system)
  - Accession number: ML022760414
- The report is also available on the NRC's public website:
  - http://www.nrc.gov/reactors/operating/ops-experience/vessel-head-degradation/news.html
- The report issuance was coordinated with other NRC offices because of ongoing NRC-related reviews
  - DBNPS plant-specific issues were provided to the NRC's 0350 Oversight Panel for follow up, as appropriate.

Results

Overall Conclusions

- NRC and industry recognized potential for this type of event nearly 10 years ago
- Initial conclusion was that vessel head penetration nozzle cracking was not an immediate safety concern
  - Further reviews became protracted
- NRC and DBNPS failed to learn key lessons from past boric acid-induced degradation events

Results

Overall Conclusions (continued)

- The leaking nozzle and vessel head degradation was not prevented
  - The NRC, DBNPS, and the nuclear industry failed to adequately review, assess, and follow up on relevant operating experience
  - DBNPS failed to assure that plant safety issues would receive appropriate attention
  - The NRC failed to integrate known or available information into its assessments of DBNPS's safety performance

Results

Overall Conclusions (continued)

- Other contributing factors
  - Guidance and requirements
  - Staffing and resources
  - DBNPS communications
  - Licensing processes and implementation

Results

NRC, DBNPS, and Industry Review, Assessment, and Follow up of Operating Experience

- Significant operating experience involving boric acid leakage and corrosion
- Generic Communication Program implementation
- Generic Issues Program implementation
- Operating experience involving foreign nuclear power plants
- Assessment and verification of industry technical information
- NRC operating experience review and assessment capabilities

Results

DBNPS Assurance of Plant Safety

- Reactor coolant system leakage symptoms and indications
- Boric acid corrosion control program and implementation
- Owners group and industry guidance implementation
- Internal and external operating experience awareness
- Oversight of safety related activities

Results

NRC Integration of Information into Assessments of DBNPS Safety Performance

- Reactor coolant system leakage assessment
- Inspection program implementation
- Integration and assessment of performance data
- Guidance and requirements
- Staffing and resources
- Davis-Besse Nuclear Power Station communications
- Licensing process guidance and implementation

Recommendations

Recommendation Areas

- Inspection guidance
- Operating experience assessment
- Code inspection requirements
- NRC programs and capabilities (including training and experience)
- Leakage monitoring requirements and methods
- Technical information and guidance
- NRC licensing processes
- Previous NRC lessons-learned reviews

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Future Activities

Senior Management Review Team

- Team of senior NRC executives reviewed report and recommendations
- Action plan developed to implement recommendations

Closing Remarks

Summary

- The NRC conducted a comprehensive, self-critical assessment of its regulatory processes as a result of the DBNPS degraded reactor vessel head.
- The NRC identified a number of areas for improvement and has initiated actions to address these areas.

Realistic LBLOCA Methodology

Presenter: Larry O'Dell
December 5, 2002
Rockville, MD

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Realistic LBLOCA Methodology

> Purpose: Provide an overview of the complete methodology, which conforms to the CSAU approach. Some selected examples will be discussed to illustrate how successful the model is in predicting key thermal-hydraulic phenomena.

> Agenda
- Requirements and Capabilities
  - CSAU Element 1, Steps 1 through 6
- Assessment and Ranging of Parameters
  - CSAU Element 2, Steps 7 through 10
- Sensitivity and Uncertainty Analysis
  - CSAU Element 3, Steps 11 through 14

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Realistic LBLOCA Methodology

> Requirements and Code Capabilities (CSAU Element 1)

- Specify Scenario (CSAU Step 1)
  - Specified the large break LOCA scenario
- Select Plant (CSAU Step 2)
  - Selected W 3- and 4-loop plants and CE plants
- Identify and Rank Phenomena (CSAU Step 3)
  - Phenomena Identification and Ranking Table (PIRT) developed

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> Requirements and Code Capabilities (CSAU Element 1)

- Select Frozen Codes (CSAU Step 4)
  - RODEX3 and S-RELAP5 codes selected
- Provide Complete Documentation (CSAU Step 5)
  - Models & Correlations, Programmers, & Input manuals developed
- Determine Code Applicability (CSAU Step 6)
  - Codes demonstrated to be applicable to selected scenario and plant types

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> Assessment and Ranging of Parameters (CSAU Element 2)

- Assessment Matrix (CSAU Step 7)
  - 15 SET facilities and 130 tests evaluated
  - 2 IET facilities and 6 tests evaluated
- Nodalization (CSAU Step 8)
  - Selected based on experience, plant studies, peer review, and assessment evaluation
  - Final nodalization has 2D components for downcomer, core, and upper plenum

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> Assessment and Ranging of Parameters (CSAU Element 2)

- Code and Experiment Accuracy (CSAU Step 9)
  - Code model biases and uncertainties determined by comparison of code to SET experiments defined in assessment matrix
    - 23 phenomena evaluated
    - 13 phenomena treated statistically
    - 10 phenomena found to be either unimportant or modeled conservatively
  - Code model biases confirmed through the performance of independent SET and IET analyses with biases applied
    - CCTF, LOFT, and Semiscale

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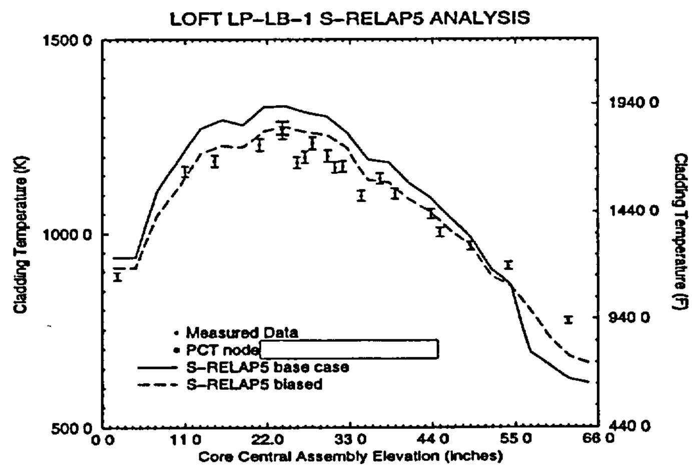
Code and Experimental Accuracy (CSAU Step 9)



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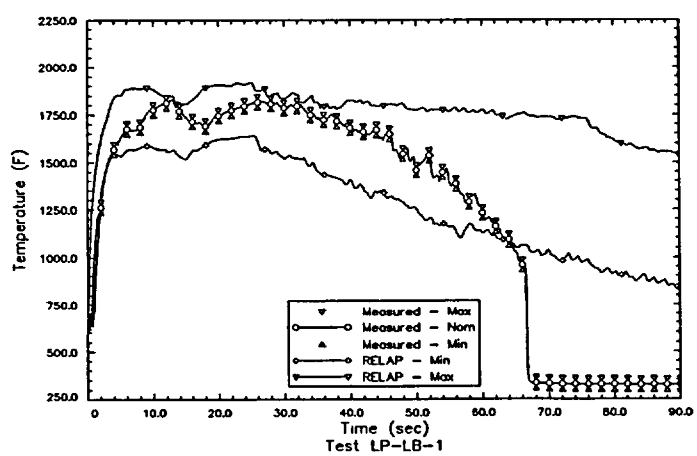
Code and Experimental Accuracy (CSAU Step 9)



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> Assessment and Ranging of Parameters (CSAU Element 2)

- Effects of Scale (CSAU Step 10)
  - Scalability of tests
    - Tests generally demonstrated to be scalable
    - Full scale UPTF tests used to address refill phase
  - Scalability of code models
    - Code models demonstrated to either be scalable, conservative, or validated on full scale tests
  - Scalability confirmed in validation of code model biases
    - Model biases generated on data from one set of SET tests and validated on different SET and IET tests of different scale

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> Sensitivity and Uncertainty Analysis (CSAU Element 3)

- Reactor Input Parameters and State (CSAU Step 11)
  - Plant input and process parameter list developed
- Plant Sensitivity Calculations (CSAU Step 12)
  - Over 250 sensitivity studies performed for plant parameters and PIRT phenomena ranked 5 or higher
    - Results confirmed PIRT rankings and defined important plant parameters
  - Plant parameters found to impact PCT included in statistical analysis
    - Analysis addresses plant specific Technical Specification

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Plant Sensitivity Calculations (CSAU Step 12)

Sensitivity Studies for LBLOCA

Case	Description	Sensitivity (°F)	Total Tolerance (°F)	Change in Tolerance (°F)
1	Axial Power Profile	181	181	181
2	F_q and F_{avg}	147	233	52
3	Film Boiling HTC	145	275	42
4	Single Phase Vapor HTC	140	308	34
5	Core Inter-phase Friction	110	328	19
6	Gap Conductivity	96	341	14
7	Pumped ECC	89	353	11
8	Condensation Inter-phase HTC in Downcomer	87	363	11
9	Upper Plenum Entrainment	81	372	9
10	$F_{\Delta H}$	74	380	7
11	Accumulator Temperature	66	385	6
12	Initial Loop Flow	63	390	5
13	Accumulator Pressure	60	395	5
14	Loop Losses	57	399	4
15	Decay Heat	54	403	4
16	Hot Leg Interfacial Drag	46	405	3
17	Core Power	43	408	2
.		:	:	:
44	CHF	2	437	0

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Realistic LBLOCA Methodology

> Determine Combined Bias and Uncertainty (CSAU Step 13)

- Uses uncertainties developed from assessments as input to analysis
- Unlike CSAU approach does not use response surface, instead uses non-parametric statistics
  - Propagates uncertainties through transient using plant model
  - Allows statistical treatment of a large number of variables
  - Provides 95/95 PCT and associated maximum nodal, and total core oxidation
  - Relies on the execution of 59 cases to determine a 95/95 condition
  - Each case defined by randomly selecting a value for each parameter being treated statistically

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Realistic LBLOCA Methodology

> Determine Combined Bias and Uncertainty (CSAU Step 13)

- Define cases to be run
  - Parameter Case 1...Case 2.........................Case N
    - A
    - B
    - .
    - .
    - .
    - .
    - .
    - .
    - ZZZ

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> Total Uncertainty (CSAU Step 14)

- The statement of total uncertainty for the analysis is given as a statement of probability for the limiting value of the primary safety criteria
- For the sample problems the limiting values for the primary safety criteria are:

	4-loop	3-loop
Criteria	Case 22	Case 41
95/95 PCT	1686 F	1853 F
Maximum Nodal Oxidation	0.8 %	1.3 %
Maximum Core Oxidation	0 02 %	0 04 %
50/50 PCT	1375 F	1500 F

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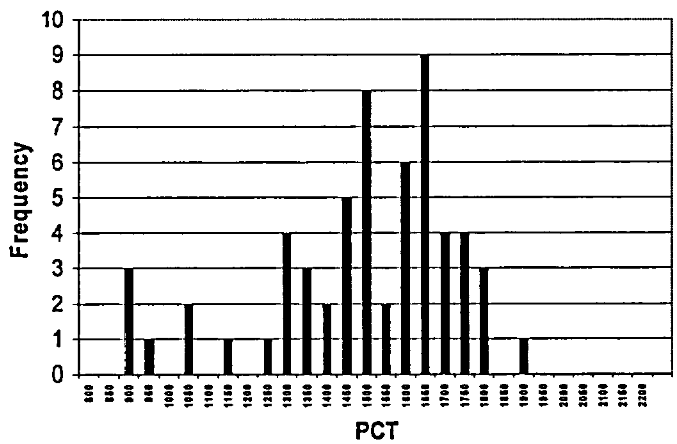
3-loop Sample Problem



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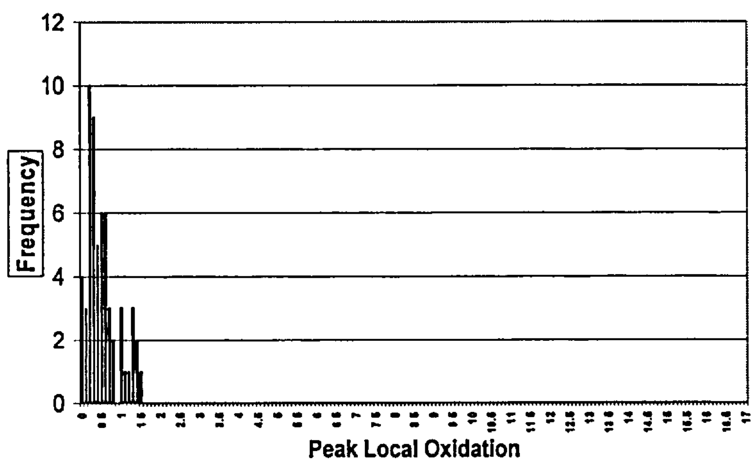
3-Loop Peak Local Oxidation



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Realistic LBLOCA Methodology

> Conclusions

- An overview of the complete Framatome ANP Realistic LBLOCA methodology has been provided
  - Demonstrated use of the CSAU methodology elements and steps
  - Demonstrated improved statistical treatment
    - Non-parametric statistics allowed treatment of a large number of parameter uncertainties, eliminating the need to determine penalties
    - Used SET's to remove biases from code models and to determine model uncertainties
    - Used IET's to evaluate code model biases on independent sets of data

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