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NUCLEAR REGULATORY COMMISSION

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498th MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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THURSDAY,

DECEMBER 5, 2002

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ROCKVILLE, MARYLAND

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The Advisory Committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., Dr. George Apostolakis, Chairman, presiding.

COMMITTEE MEMBERS:

GEORGE E. APOSTOLAKIS, Chairman

MARIO V. BONACA, Vice Chairman

F. PETER FORD, Member

THOMAS S. KRESS, Member

GRAHAM M. LEITCH, Member

DANA A. POWERS, Member

VICTOR H. RANSOM, Member

STEPHEN L. ROSEN, Member

COMMITTEE MEMBERS (CONT.)

WILLIAM J. SHACK, Member

JOHN D. SIEBER, Member

GRAHAM B. WALLIS, Member

ACRS STAFF PRESENT:

JOHN T. LARKINS, Executive Director

SHER BAHADUR, Associate Director

PAUL A. BOEHNERT

HOWARD J. LARSON, Special Assistant

ALSO PRESENT:

JACK GROBE, NRC

ART HOWELL, NRC

RALPH R. LANDRY, NRC

JIM MALLAY, Framatome ANP

LARRY O'DELL, Framatome ANP

C-O-N-T-E-N-T-S

C-O-N-T-E-N-T-S (CONT.)

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

8:30 a.m.

CHAIRMAN APOSTOLAKIS: Good morning. The meeting will now come to order.

This is the first day of the 498th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting the Committee will consider the following:

Davis-Besse Lessons Learned Task Force and Status of NRC Oversight, 0350, Panel's Investigation of the Davis-Besse Event.

Framatome ANP, Inc., S-RELAP5 Realistic Large-Break LOCA Code.

Meeting with Mr. Lawrence Williams, the United Kingdom.

North Anna and Surrey License Renewal Application.

Status of Development of the Review Standard for Power Uprates.

Supplementary Report on the Rod Bundle Heat Transfer Experimental Program.

Proposed ACRS Reports.

Portions of this meeting have been closed to discuss Framatome ANP, Inc., proprietary information and the information provided in confidence by a foreign source.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Dr. John T. Larkins is the Designated Federal Official for the initial portion of the meeting.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions.

A transcript of portions of the meeting is being kept, and it is requested that the speakers use one of the microphones, identify themselves, and speak with sufficient clarity and volume so that they can be readily heard.

I have a few comments before we start on an item of great current interest. Mr. Paul Boehnert, ACRS staff thermal hydraulic expert, is retiring on January 30th, 2003 after 30 years of dedicated service to the Advisory Committee.

During his tenure with the ACRS, he provided outstanding technical support to the ACRS in reviewing highly-complex technical issues in numerous areas as well as in thermal hydraulics (laughter) -- no, no, no -- numerous areas, most notably thermal hydraulic codes, naval reactor submarine designs, severe accident issues, control room habitability issues, resolution of several generic safety issues and unresolved safety issues, revisions to Appendix K to 10 CFR Part 50, and thermal hydraulic issues associated with the Westinghouse AP600, Combustion Engineering System AD-Plus, and General Electric ABWR designs.

His dedication, hard work, and contributions are very well appreciated by my colleagues. We wish him a happy and healthy retired life. We are planning to have a retirement party for Paul in January, when the members will not be here (laughter), but that will happen before he leaves.

So, Paul, we wish you happy retirement.

MR. BOEHNERT: Thank you very much.

(Applause.)

CHAIRMAN APOSTOLAKIS: Now we are ready to start with the important business of the day, unless a member has something to say or bring up.

(No response.)

Okay, the first item on the agenda is the Davis-Besse Lessons Learned Task Force Report and Status of NRC Oversight Panel's Investigation of the this Event. The cognizant member is Dr. Ford.

MEMBER FORD: Thank you. We are going to

hear two topics related to Davis-Besse, both given by staff members.

The first one is to do with the Inspection Manual Chapter 0350, the Oversight Panel, relating to the performance issues and restart issues for Davis-Besse.

The second topic is Davis-Besse Lessons Learned Task Force Report, which has been completed. It is an independent evaluation of the NRC regulatory processes associated with the RPB integrity at Davis-Besse and plus recommendations. This is for information only and no letter is being requested at this time.

Jack, thank you for coming in on a day like this, and I turn it over to you.

MR. GROBE: I appreciate that. Thank you very much. I flew in last evening and the weather was great.

(Laughter.)

My name is Jack Grobe. I'm in the Region III office of the NRC in Chicago, Illinois, currently assigned full time as the Chairman of the Davis-Besse Oversight Panel. I'm happy to be here.

This is our third briefing of the Committee on activities at Davis-Besse. The first briefing was in April, when we presented the NRC's Augmented Inspection Team findings, the facts and circumstances surrounding the discovery of degradation in the head of the reactor pressure vessel at Davis-Besse.

In June the Oversight Panel had been chartered, and I appeared before you presenting the charter for the Panel, the composition of the Panel and its functions, as well as summarizing the FirstEnergy's Return-to-Service Plan.

Next slide, please. My objectives today are to update you on the activities of the Panel, to summarize the results of recent inspections that we've completed and describe several significant plant equipment issues that Davis-Besse is attempting to resolve.

Next slide, please. The guiding document for the NRC's oversight of activities at Davis-Besse is what we refer to as the "Restart Checklist." The Checklist provides a focus for the inspection activities at the site. It captures all safety issues that require resolution for sustained safe operation of the facility. The Checklist was issued in August and updated most recently in October.

Next slide, please. There's six key areas of concern that address people, programs, and equipment at the facility. I'm going to get into each of these in a little bit of detail, but they start with the root causes of the event that occurred, as well as addressing structures; as I mentioned, the people, the organization, the management, the safety culture, and licensing issues also.

MEMBER LEITCH: Jack, just for clarification, is what you're describing, the Oversight Panel, is that also the 0350 review --

MR. GROBE: Yes, I'm sorry.

MEMBER LEITCH: -- or is that something --

MR. GROBE: No, 0350 is a procedure number. It's Manual Chapter 0350 --

MEMBER LEITCH: Right.

MR. GROBE: -- which describes the function of an Oversight Panel.

MEMBER LEITCH: Okay, thank you.

MR. GROBE: The first item on the Restart Checklist is the adequacy of the root cause determination. There's two parts to that. One is the hardware issues, which you heard a great deal about in June. That is the cause of the cracking and the cause of the corrosion.

The second area is what I call soft

issues. That's organizational issues, human performance, supervision and management structure. FirstEnergy has separated this into a number of separate areas. They have separate causal analyses on the organization, the engineering function, the operations function, corporate oversight of the facility, the function of the safety committees, and a function of quality assurance. There were a number of performance deficiencies in each of those areas, and they did separate root cause analyses in each area.

The second item on the Restart Checklist is adequacy of structure, systems, and components. That has a number of attributes under it.

First, of course, is the replacement of the reactor pressure vessel head, the containment restoration following movement of the new head into containment and the old head out.

Structure, systems, and components inside containment, that has several aspects to it. One is the impact of the boric acid environment that was inside containment. Second is operability of the systems considering the organizational failures and corrective action and design.

The third issue that has been identified has to do with containment coatings. I have a later presentation on that issue.

In addition, inside containment, the licensee has chosen to make substantial modifications to the sump, the emergency core cooling system and containment spray sump, and I also have some additional information on that later.

Systems outside containment, there are some systems that do carry boric acid, water with boric acid additive, and we're focusing on boric acid aspects of those, as well as the operability of systems.

The next slide, please. The safety-significant programs, each of these programs had some contribution to the failures that occurred at Davis-Besse. FirstEnergy is doing detailed reviews of these programs, and we are providing oversight of those activities.

The final item on the list is the Radiation Protection Program. There was a situation that occurred in February involving occupational and public radiation safety, which resulted in a number of deficiencies being identified in the Radiation Protection Program. Those have been added to the Restart Checklist. Those aren't related to the reactor head degradation.

CHAIRMAN APOSTOLAKIS: Was there any question ever whether the programs were adequate? My understanding is that they were not implemented well.

MR. GROBE: Some of the programs did not meet expectations. I'll present some details in the findings of the AIT follow-up inspection.

CHAIRMAN APOSTOLAKIS: Okay, fine.

MR. GROBE: But you're correct, Dr. Apostolakis, that many of the programs were adequate as written and, had they been implemented correctly, would have prevented the problems.

The next area on the Checklist --

CHAIRMAN APOSTOLAKIS: One other thing.

MR. GROBE: Sure.

CHAIRMAN APOSTOLAKIS: This is the NRC oversight of the station. You have this Restart Checklist, and so on. Are you doing something similar through the NRC itself?

MR. GROBE: Yes, and I think that's what Art is going to be talking about.

CHAIRMAN APOSTOLAKIS: Okay.

MR. GROBE: Dr. Ford, did you have a question?

MEMBER FORD: Yes, I was about to say that this is a checklist; you're going to go into some of these deficiencies?

MR. GROBE: Yes.

MEMBER FORD: Okay.

MR. GROBE: And if I don't hit an issue -- Maggalean said I had 15 minutes.

(Laughter.)

And she's a pretty tough task master.

MEMBER FORD: I know.

(Laughter.)

MR. GROBE: So I am trying to get through this quickly, just to give you a broad overview, and I would be glad to answer any questions.

CHAIRMAN APOSTOLAKIS: To just do a double-check, Art, are you going to need the full time?

MR. HOWELL: I'm Art Howell. My presentation is about 45 minutes.

CHAIRMAN APOSTOLAKIS: Okay.

MR. GROBE: The next area is organizational effectiveness and human performance. I separate this area into five categories. One is the performance of the people. Second is performance of the supervision and management. The third area is organizational structure. Fourth is safety culture, and fifth is safety-conscious work environment.

FirstEnergy has initiated activities in all of these areas, and we're providing oversight of those activities.

CHAIRMAN APOSTOLAKIS: Now here is where we're getting into soft territory.

MR. GROBE: Absolutely.

CHAIRMAN APOSTOLAKIS: Do we have any criteria as to what is adequate? Or is it a matter of judgment?

MR. GROBE: We don't have specific criteria defined. As a matter of fact, last night I read some work that was done by the ACRS in the area of safety culture.

CHAIRMAN APOSTOLAKIS: And I'm sure that did not enlighten you any more than you were already enlightened.

MR. GROBE: It enlightened me on a lot of work that's being done both in the United States and internationally.

CHAIRMAN APOSTOLAKIS: Yes.

MR. GROBE: The impact of these activities is observable in performance, particularly in the area of safety culture and safety-conscious work environment. In examining the implementation of the

Corrective Action Program, you can see the organizational safety culture.

CHAIRMAN APOSTOLAKIS: The problem with performance is that it may be too late then. If you were waiting until you see the impact of performance of a bad culture, it may be late.

But you're absolutely right. I mean, this is an area where we really don't know what is good enough or adequate, and so on. So I was curious how your people are going to decide this. I guess it's common industry practices perhaps? That's adequate? The experience of people and saying, okay, if everybody is doing this and it has worked for years, it must be adequate?

MR. GROBE: Our judgment in this area is primarily driven by performance. Prior to restart, we have to have a change in the character of the safety culture of the organization, and we're already seeing that in how the organization performs.

Part of the Manual Chapter 0350 includes continuation of the Panel well after restart, to continue observing the performance of the facility to ensure that the actions that were taken are lasting.

CHAIRMAN APOSTOLAKIS: Now "Panel," you are referring to your Panel?

MR. GROBE: That's correct.

CHAIRMAN APOSTOLAKIS: And your Panel will have more authority than other panels?

MR. GROBE: No. The purpose of the Panel -- I apologize, I should have stepped back -- the purpose of the Panel is essentially to replace the Routine Oversight Program. At Davis-Besse the Routine Reactor Oversight Program is suspended, and the Panel is comprised of both people from the Regional Office as well as Headquarters. We assess all the findings and define the Inspection Program.

CHAIRMAN APOSTOLAKIS: So this Routine Oversight Program that you are referring to is the new, revised oversight process?

MR. GROBE: That's correct.

CHAIRMAN APOSTOLAKIS: Is this statement you just made consistent with statements we hear from other groups of the staff, that this revised reactor oversight process is a successful program? I mean, you are suspending it.

MR. GROBE: Yes, it's suspended not because --

CHAIRMAN APOSTOLAKIS: And yesterday we were told it's successful.

MR. GROBE: It's not suspended because of a lack of success. It's suspended because it's constructed to deal with a routine reactor plant, and the Davis-Besse organization has demonstrated that they don't have the fundamental underpinnings that resulted in formation or that were the foundation of the Reactor Oversight Program, the Routine Reactor Oversight Program. Because of that, different types of inspection and oversight are necessary.

The Panel was put together to provide guidance and oversight of that different type of inspection program. We take the vast majority of the guidance from the Routine Oversight Program to guide the activities that we do. But, in addition to that, all of these items on the Checklist are being followed up in substantially more detail and depth than would be dictated by the Routine Oversight Program.

CHAIRMAN APOSTOLAKIS: So at some point in the future, then, based on your experience here, we may expand the scope of the ROP to include some of the issues that you're addressing here, like the adequacy of root causes; I don't think they do that, do they?

MR. GROBE: Yes. Part of the Routine Oversight Program is evaluating --

CHAIRMAN APOSTOLAKIS: It is done?

MR. GROBE: -- on a regular basis the

Corrective Action Program. But the group that Art chaired was tasked with evaluating the effectiveness of the Routine Oversight Program as well as many other aspects of the agency. The Senior Management Review Team, chaired by Carl Paperiello, is evaluating the results of Art's group's findings right now. Art will get into a lot more detail on it.

CHAIRMAN APOSTOLAKIS: Okay.

MEMBER LEITCH: Are these learned items categorized as to which ones need to be completed prior to restart versus some that may be gone and continued after the plant is in operation?

MR. GROBE: The answer is yes to both of those. All of these issues have to be addressed prior to restart, such that we have adequate confidence that the plant not only can be restarted safely, but will continue operating safely.

Many of the activities will continue to be implemented long after restart. One example is the design reviews. FirstEnergy initially chose five systems to do very detailed design reviews on an additional 31 systems to do what I would call an operational review. They're planning now, based on their findings, of expanding the number of systems for design review, but they're going to continue doing those design reviews after restart.

MEMBER LEITCH: Is there a part of the program related to measuring the effectiveness of these corrective actions? In other words, oftentimes, one needs to go back three months, six months, after a corrective action has been taken and assess whether that corrective action really solved the problem or not.

MR. GROBE: Yes.

MEMBER LEITCH: Is that part of this program?

MR. GROBE: Yes. Our inspections are structured in a way that we go back many times. The first step of the inspections is evaluating the root cause analysis in each area. The next step is evaluating the licensee's proposed actions and whether or not they are likely to address that root cause.

Then we observe the implementation of their actions. Then we perform independent inspections of our own to ensure that those corrective actions both were adequate in depth as well as we had the appropriate extent of condition consideration.

So we look at each step. Some of the effectiveness inspections have already been performed. Particularly in the design area, we found that the corrective actions they were taking were well-implemented but not sufficient. The company is now going back and broadening the scope of those actions.

MEMBER LEITCH: Is there a nexus or a linkage between the corrective actions and the root causes? In other words, can you look at the list of causes and say these are the corrective actions that address that?

MR. GROBE: Yes. That's one of the expectations of the inspections.

MEMBER LEITCH: Okay.

MR. GROBE: Dr. Shack, did you have a question?

MEMBER SHACK: You were implying that some of the changes in organizational effectiveness were reflected in the performance; you can see it. I was just wondering what measures of performance you were considering when you made that statement.

MR. GROBE: One of the areas that is easiest to see that is in FirstEnergy's assessment of Operations. They concluded that over the past three to seven years the Operations leadership of the organization was suppressed through a number of activities, including behavior and performance of management, expectations set by management, organizational silos, competing goals of different parts of the organization.

The outcome of that was a significant reduction in the Operations leadership of the organization, which contributed to a loss of a safety culture. So those are the types of issues.

Okay, next slide, please. Just prior to restart -- I've had a number of experiences with these types of plants. One of my experiences is that, when you have a plant in long-term shutdown, you have to spend a significant amount of effort towards the end of that shutdown to make sure that you're ready for restart.

So just prior to restart there will be a series of inspections that will deal with systems returned to service and, most importantly, it will focus on operators, the operational organization and their readiness to handle a plant in an operating condition as contrasted with a shutdown condition.

So there will be some effort, several weeks of inspection towards the end of the outage that are focused in those areas. Of course, there will be some different types of tests that are done just prior to restart.

The licensee is planning a somewhat unique pressure test, and I will get into that in a little bit more detail, of the reactor coolant system as well as containment-integrated leak rate test.

MEMBER LEITCH: That operational readiness will be heavily focused on simulator performance?

MR. GROBE: No. It will include round-the-clock observation of operators in the control room and still occur after a great number of systems have been returned to an operational condition where the operators have to deal with day-in and day-out maintaining the systems in a readiness state, dealing with the normal types of corrective maintenance activities that occur and plant activities that occur: systems in and out of service, hanging outages, things like that.

VICE CHAIRMAN BONACA: Was Operations aware of the existence of those rust deposits on the head?

MR. GROBE: Not according to the licensee's root cause report, no.

VICE CHAIRMAN BONACA: So they were not involved in the observations?

MR. GROBE: That is correct, they were not involved. Part of that had to do with organizational communications. Part of it had to do with an inappropriate emphasis on radiological controls.

VICE CHAIRMAN BONACA: That's interesting.

MEMBER LEITCH: Do you know, if you're not looking at simulator performance, though, do you know if the licensee intends to do some just-in-time simulator training of the crews?

MR. GROBE: Yes, they do. I didn't mean to imply that we weren't focused on simulator. I wanted to make sure it was clear that we were focused on what was going on in the plant.

MEMBER LEITCH: Right.

MR. GROBE: The company has continued its full requalification training program throughout the outage, and we continue to perform routine inspections of that.

The final activity is licensing issues and confirmatory action letter resolution. There remain three limited ASME code relief requests regarding the new head. None of those are particularly unique or complicated. Then the licensee is required to meet with the NRC publicly prior to restart to obtain restart approval in accordance with the confirmatory action review.

We have a number of inspections that have either recently been completed or are still ongoing.

As you will recall from my presentation on the Augmented Inspection Team, that inspection was simply fact-finding. We had to perform a follow-up inspection to put those findings, those facts and issues, into a regulatory context. I will go into some detail on the findings that came out, the regulatory findings that came out of that follow-up inspection.

We have completed the reactor vessel head replacement inspection. I will get into that.

We have completed the containment health assurance. That's what the company calls the program for examining systems inside containment.

The other three inspections are still ongoing. System Health Assurance, that's the design and operational review of the systems outside containment; program effectiveness and the organization and human performance inspections are ongoing.

First, the Augmented Inspection Team followup: There were a number of violations that came out of that. All of these violations currently are being handled as unresolved items because the significance of the violations hasn't been determined.

The first is that the technical

specifications do not permit pressure-boundary leakage, and in this situation it is clear that there was pressure-boundary leakage, and it was pressure-boundary leakage that the licensee clearly should have known about. That's a violation of the technical specifications.

There was a number of failures to implement corrective actions in accordance with Appendix B of 10 CFR Part 50. I have listed those there.

I believe that all of these you're familiar with. If anybody has a question on any of these specific issues, I would be glad to address it.

MEMBER LEITCH: The significance of the violations, it surprises me that these individual violations are still being treated as unresolved items. In a situation like this where there are a number of violations, I mean I know we haven't assigned a color to the overall event, but is it not a relatively easy task to assess the individual violations and assign a severity level to those?

MR. GROBE: Yes. We wouldn't assign a severity level unless the violations -- well, there's one area, and that's the final violation, which I will get to, regarding completeness and accuracy of information. But the rest of the violations, the significance of them will be driven by the risk significance of the outcome, which is the hole in the head.

Each of these violations individually will not be assessed a separate significance because each of them contributed to the eventual outcome, the degradation of the head.

MEMBER LEITCH: Okay. So all the individual violations, then, are still in this unresolved status until the overall issue is resolved?

MR. GROBE: That's correct, and I believe that the way we'll handle this is one significance for all the violations associated with the head degradation.

CHAIRMAN APOSTOLAKIS: Why was the installation of the service structure access modification a violation? I mean, they decided to do it themselves, didn't they?

MR. GROBE: It was part of the corrective action for an identified deficiency.

CHAIRMAN APOSTOLAKIS: Was there a commitment to the NRC that they would do this?

MR. GROBE: No. Within their Corrective Action Program, I don't remember which year it was, but the engineers documented that they were unable to completely clean and inspect the head.

CHAIRMAN APOSTOLAKIS: Right.

MR. GROBE: One of the corrective actions for that was to install these openings, and the company never did it. So it was a violation of the Corrective Action Program. They never corrected the deficiency of being able to --

CHAIRMAN APOSTOLAKIS: So there is a requirement, then, somewhere that they have to have access?

MR. GROBE: No, the requirement is to take corrective actions for identified deficiencies. The deficiency was --

CHAIRMAN APOSTOLAKIS: But why was it deficient?

MR. GROBE: Because they couldn't implement their Boric Acid Corrosion Management Program.

CHAIRMAN APOSTOLAKIS: Okay.

MEMBER SIEBER: Do you believe that they ultimately, the staff will ultimately determine the significance of the agglomerated violations?

MR. GROBE: Yes. Yes, that's nearing completion. Members of the public that are here that attend my other meetings know that I have said that on several occasions, but, in fact, NRR, the Office of Nuclear Reactor Regulation, is completing what we call a Phase III Risk Analysis of the head degradation. I expect to have that this week.

Once that's completed, we can develop the significance evaluation. It will probably take another four to six weeks to complete that, but we're on the home stretch.

CHAIRMAN APOSTOLAKIS: That will be the color for the ROP?

MR. GROBE: That's correct.

CHAIRMAN APOSTOLAKIS: Why? What use would that have?

MR. GROBE: Well, one of the purposes is communication. One of the reasons we put colors on violations is to communicate effectively with the public. Clearly, the public could infer that this is a very significant issue based on the actions the agency has taken.

But the second important reason is to exercise the program and to make sure it works, and if it doesn't work effectively, to be able to make changes to it.

CHAIRMAN APOSTOLAKIS: I don't think it

works. So the color is irrelevant to me. If it didn't find something -- I mean, that's a personal opinion -- it doesn't work.

MR. GROBE: I was specifically talking about the significance determination process, whether that works for the situation, and if it doesn't, decide whether or not we should make changes.

CHAIRMAN APOSTOLAKIS: Yes. I mean, the process requires some inputs, right?

MR. GROBE: I'm sorry?

CHAIRMAN APOSTOLAKIS: The process, for the process to work, the SDP, you have to have the inputs?

MR. GROBE: That's right.

CHAIRMAN APOSTOLAKIS: What was missing here were the inputs. So it is not going to tell you really whether the process works. It's going to tell you whether we have a system in place that actually gets those inputs in time. I don't know how you do that. This is a cultural issue, an organizational issue.

MEMBER SIEBER: Well, one of the problems is --

VICE CHAIRMAN BONACA: It looks at the right things.

MEMBER SIEBER: One of the problems is that the NRC has already acted as they would have through the action of the action matrix. So it is sort of predetermined, the color this ought to turn out to be.

Now the question is, will the fact that the Commission has acted and all this information has come to light, will that have an influence on what color the SDP finally determines this to be or will there be a bias? And if there is, then you can't establish that the SDP is actually doing its job.

MR. GROBE: And those are the issues that we're working through right now.

MEMBER SIEBER: Okay. I anxiously await the outcome.

MR. GROBE: So I'm invited back again?

(Laughter.)

MEMBER POWERS: Anytime you want to appear, you're very welcome here.

MEMBER SIEBER: My term expires in August.

CHAIRMAN APOSTOLAKIS: Next time we have a snowstorm.

(Laughter.)

MEMBER POWERS: Or even a heat wave.

CHAIRMAN APOSTOLAKIS: Or a heat wave,

yes.

(Laughter.)

MR. GROBE: Next slide. The next violation concerned the failure to have an adequate Boric Acid Corrosion Management Program. The program that was in place would have been sufficient, had it been correctly implemented, but there were a number of deficiencies in the program. I would call them more administrative-type deficiencies of how the Boric Acid Program interfaced with other plant programs and the guidance that it provided.

There were a number of deficiencies in the Corrosion Control Program. Of course, there was a number of occasions where FirstEnergy failed to follow both the Boric Acid Corrosion Control Program and their corrective action procedures.

The final item, there were six examples identified by the Augmented Inspection Team of failure to provide complete and accurate information. This included both information which was submitted to the NRC as well as information that was contained in required records; 10 CFR 50.9 addresses both of those issues. There are a number of records as well as submittals to the company that were not complete and accurate.

MEMBER WALLIS: Does this mean that they did not supply the information or that they supplied inaccurate information?

MR. GROBE: This primarily focuses on the completeness and accuracy of the information they provided.

MEMBER WALLIS: So it was omission that you're after here or was it providing information which was in some way misleading?

MR. GROBE: Yes, it's more of the second.

MEMBER WALLIS: More the second? Okay.

MR. GROBE: Yes, that the information that was provided is not complete and could lead you to an incorrect conclusion.

Again, I want to emphasize that this is not just submittals to the NRC, but it's also internal records.

MEMBER SIEBER: Was any of it under oath and affirmation?

MR. GROBE: The submittals to the NRC I believe were submitted under oath and affirmation.

Okay, the next slide. As I mentioned, we have completed the reactor vessel head replacement inspection.

MEMBER LEITCH: Jack, just before you get into --

MR. GROBE: Sure.

MEMBER LEITCH: -- the hardware side of the issues there, I'm concerned that it appears to me, and I have not been to the plant, but it appears to me as though Operations was not really the driving force as to what was occurring at the power plant --

MR. GROBE: Right.

MEMBER LEITCH: -- in the years prior to this event. In all power plants there are a number of organizations. But it seems to me that the plant basically needs the attitude that Operations is in control and that the rest of them are there, the rest of the organizations are there in one way or another to support the safe operation of the plant.

What are the actions that are being taken to change that kind of a mindset, and how can you determine when those actions have been successful? I mean, in my mind, Operations has got to be in charge.

MR. GROBE: Absolutely.

MEMBER LEITCH: Apparently, that was not occurring. I just wonder, what is the licensee doing? How can we know when it's done? What are the measures that we have in that area?

MR. GROBE: Thank you for that question.

Let me give a few more details about revelations that came through the FirstEnergy review of Operations. This is one of the reasons they separated that out as a separate causal analysis.

Operations in the late nineties was characterized by a significant turnover in leadership. The lack of support -- as a matter of fact, the Operations Superintendent position, which reports to the Plant Manager, was vacant, and the current Shift Managers did not submit themselves for that promotion opportunity because of their belief in the lack of management support for Operations.

The Onsite Review Committee would be conducted without an Operations representative. They had a quorum requirement that didn't require Operations. There's a number of other examples which are clearly indicative that Operations wasn't playing a leadership role in the day-to-day activities of the plant.

The actions that the company has taken is that there are required Operations representatives on all the key committees, the Onsite Review Committee, the Corrective Action Review Board, all of the key committees that are ongoing.

MEMBER LEITCH: So they're quorum

requirements that can't be substituted?

MR. GROBE: That's correct.

MEMBER LEITCH: You have to have those folks there?

MR. GROBE: A Licensed Senior Reactor Operator was added to the Health Physics Organization and to what's commonly referred to as the "fix-it-now" part of Maintenance, so that there's a clear operational perspective in decisions that are made in the radiological protection and the urgent maintenance activities.

All of the Operations supervision and management has been replaced. A number of those people have come from outside the organization. They were specifically selected for their leadership.

MEMBER LEITCH: This is the Shift Managers you're referring to now?

MR. GROBE: No, above Shift Managers.

MEMBER LEITCH: Above Shift Managers, yes.

MR. GROBE: Not the licensed positions, but the positions above that.

One of the other findings was that the Shift Manager wouldn't attend the morning management briefings.

So there were a number of indicators that

Operations was not playing the role that you would expect. All of that is now observably changed.

The longer-term barriers that need to be broken down are the organizational barriers to ensure that Maintenance and Engineering and Radiological Protection, in particular, are supporting Operations and not any other type of hierarchy.

We have two Residents onsite. We'll continue to observe these things on a day-to-day basis as well as special inspections specifically focused in this area.

MEMBER LEITCH: The Shift Managers, do they get to be Shift Managers by virtue of a seniority progression or is there other more stringent qualifications?

MR. GROBE: I don't --

MEMBER LEITCH: Maybe that's not -- maybe that's in the licensee's decisionmaking process?

MR. GROBE: Exactly. I think that is more of a management decisionmaking process that they have, and I don't have detailed knowledge on that.

MEMBER LEITCH: It's hard for me to understand a Shift Manager not attending the morning meeting. In fact, it's hard for me to imagine him not chairing the morning meeting.

(Laughter.)

VICE CHAIRMAN BONACA: Well, but the fact that Operations was unaware of those photographs of the head and the corrosion taking place up there, it shows there was -- I mean, just it's unheard of. I mean, where were they during the outage? How come this information wasn't shared, I mean to the people that run the plant?

MR. GROBE: Let me answer both your questions. The flavor of the organization, the organizational priorities, don't come from the Shift Manager. They come from the senior executives and the leadership at that level, and it's infused down through the organization. That wasn't occurring. That is what allowed this atrophication of support of Operations, operations safety, to occur.

MEMBER WALLIS: Well, maybe it was occurring, but the wrong kind of thing was occurring. I mean, it was diffusing down through the organization, but it was the wrong kind of directive.

MR. GROBE: If you looked at the paperwork that existed, you would find many of the right words, but the day-to-day behavior of the executives and managers didn't support Operations leadership.

MEMBER FORD: Jack, could I ask, just in

the process of time, could you finish up within 10 minutes?

MR. GROBE: Sure.

MEMBER FORD: I recognize that you can't control the questions.

MR. GROBE: I believe there was one other question. That had to do -- I'm not sure who asked it -- it had do with bench strength.

If you go back to the mid- to late eighties, Operations had roughly 40 to 50 licenses, and that was built to the early nineties up to about 100 licenses onsite. That's now back down, or had been back down, to the level of on the order of 40 to 50 licenses. So there was less emphasis on licensed operators in the organization and license operator training.

MEMBER SIEBER: Isn't that an impediment to already-licensed operators in radiation control and work management and all these different places?

MR. GROBE: Yes, it is. One of my experiences in an operations-driven organization is that either you drive licensed operators from operations into other organizations or you license in other organizations, particularly engineering.

MEMBER SIEBER: Right. But that hasn't

been happening in the recent pattern?

MR. GROBE: That's correct.

MEMBER LEITCH: I would just point out, though, that too many licensed operators can also be an impediment. I mean that can be a two-edged sword. I think you want people migrating into these organizations who have been previously licensed, but sometimes maintaining the license can be a burden because they have to go to requal. training; they have to take exams.

I'm not sure the exam is focused on team performance, but we always found it kind of difficult to get a few people that weren't active operators together in a control room to pass an exam because they weren't used to working with one another.

So, I mean, the first reaction is the more licenses, the better, and in general I agree with that. But there's another side to that coin where you can have too many licenses and it can be a burden and make your licensee failure rate on exams look bad and require a great deal of time for requalification, and so forth.

MR. GROBE: Yes. I think I was trying to focus more on the fact that, with fewer licenses, there's less ability to have turnover --

MEMBER LEITCH: Right.

MR. GROBE: -- out of the operations organization into other organizations. As a result of that, you don't have an operational focus in those other organizations.

The new reactor head, the replacement reactor head, which has never been used, we have concluded met, does continue to meet, the ASME Section III requirements. We witnessed and evaluated the non-destructive examination of that head. A number of the radiographs had to be reperformed because they were not maintained, and baseline Section 11, ISI, was performed on the penetrations and the welds. That all has been accomplished successfully.

As I mentioned earlier, there's two outstanding issues in this area. One is the reactor coolant system pressure test and the containment integrated leak rate test. Those will be performed later at an appropriate time.

MEMBER SIEBER: Where is the head right now?

MR. GROBE: It's inside containment on the head stand.

MEMBER SIEBER: Okay.

MR. GROBE: There was quite a bit of --

MEMBER SIEBER: At Davis-Besse?

MR. GROBE: Yes. There was quite a bit of reconstruction work that had to be done, attaching the service rupture, installing all the control rod drive mechanisms, all of the support structures for that.

MEMBER SIEBER: And the Davis-Besse containment is closed now?

MR. GROBE: Yes, it is.

MEMBER SIEBER: Okay, and will there be a design pressure test in the containment prior to start --

MR. GROBE: There will be a containment integrated leak rate test, not a structural integrity test.

MEMBER SIEBER: Okay. So what's the test pressure for these? Would it be 10 pounds?

MR. GROBE: No, no. The containment, I believe, Pat, the containment integrated leak rate test pressure at Davis-Besse is at 42 pounds?

MR. McCLOSKEY: I don't have the figure for that, but I think the question was whether a design pressure test would be --

MEMBER FORD: You have to come to the microphone.

MR. McCLOSKEY: Good morning. My name is

Pat McCloskey. I'm the Regulatory Affairs Manager for Davis-Besse.

The question was in regards to the test plan for the containment reactor building. We plan to do an integrated leak rate test versus a design testing. Integrated leak rate test, of course, is similar to what we run as part of our 10-year in-service inspection requirements, and that has been part of the plan of restoration all along.

MR. GROBE: The second inspection has been completed.

The next slide is the containment health assurance -- that's what the licensee calls it -- area evaluation. The containment has been thoroughly inspected. The evaluation of structure, systems, and components inside containment has been adequate, based on our inspections, and repair and refurbishment activities in a number of systems are ongoing, most notably the ventilation systems inside containment.

There was a substantial accumulation of boric acid inside ductwork. That was the primary impact of the boric acid, was on the ventilation systems.

One of the outstanding --

MEMBER WALLIS: Doesn't this affect

instrumentation as well?

MR. GROBE: The environmental qualification requirements for equipment inside containment include ability to resist a boric acid environment, and their operators were opened; junction boxes were opened. No significant findings of any nature were --

MEMBER WALLIS: You just dust them off or whatever, and they're okay inside?

MR. GROBE: In fact, there was little penetration of any boric acid into those components.

There's an issue which I will get into in more detail later on reactor pressure vessel bottom head penetrations that needs to be resolved.

The next issue is completely unrelated to the boric acid. During their inspections they identified a cut in a splice, an electrical splice, and that cut appeared to be an impact of maintenance activities that were performed incorrectly. The licensee is currently evaluating the extent and condition of that, whether there was an impact or an outcome of a routine activity replicated a number of times or if it was an isolated issue.

The other interesting thing at Davis-Besse is that the electrical conduits provide a ground path, and there was some corrosion identified on the conduits. The question concerns whether that corrosion prohibits the function of the grounding circuit of the conduits. So those are the three outstanding issues in this unit.

System health assurance, as I mentioned earlier, this was a detailed design review of selected risk-significant systems and an operational review of other systems. Our inspections concluded that the review process and approach that the licensee was taking was adequate.

They identified a number of design and operational issues with several systems, including some issues that were cross-cutting across a number of systems. We performed an independent design inspection of additional systems that they didn't review and identified similar issues.

Davis-Besse is currently evaluating the scope expansion that they believe is necessary to address these issues.

The next slide is program effectiveness. This inspection is in its early stages. That is primarily because the licensee is in the early stages of addressing this issue.

This is reviewing and evaluating the

programs that I identified earlier in the Checklist. The review process they are using is adequate, but they have not completed a significant number of these programs yet. So our review is pacing with their activities.

Organizational human performance, we've completed a review of the majority of the root cause analyses. The licensee has initiated a broad spectrum of corrective actions in a number of areas, including safety culture and safety-conscious work environment. Again, this instruction is fairly early on in its implementation because the licensee's activities are continuing.

CHAIRMAN APOSTOLAKIS: How are they doing this? How does one inspect the safety culture?

MR. GROBE: Again, I don't know of a way to directly inspect safety culture. There's no standards.

What you do is you inspect the questioning attitude of the individuals, how they evaluate deficiencies that they come across, the depth of that evaluation, the effectiveness of corrective actions. Not only the identification of the action, has it been identified correctly --

CHAIRMAN APOSTOLAKIS: Is it possible,

though, that you have a Heisenberg effect here: Because you are there, the process has been changed? They know they are being --

MR. GROBE: I would say it differently. I think, because of the revelations that this event has occurred, FirstEnergy has become aware and has taken significant actions. It's because of the event --

CHAIRMAN APOSTOLAKIS: Yes.

MR. GROBE: -- that revealed these deficiencies and a recognition on the part of FirstEnergy executives and management that these things have to be fixed if they're going to have an asset that is valuable in the future.

MEMBER FORD: I'm sorry, but we must finish by 25 past if Art is to have any adequate time.

MR. GROBE: Okay. Thank you.

MEMBER WALLIS: That's too bad because the interesting part we haven't gotten to yet.

MR. GROBE: Let me get into several plant equipment issues, first the bottom head issue. The containment sump, an area in containment referred to as the decay heat valve pit and the coating.

Next slide. This is a photograph of penetration No. 1 on the bottom of the head. We're looking up at the bottom of the head. These are the in-core nozzles for the detectors. They're very small in diameter, about an inch diameter.

What you're seeing here, if you looked at a number of photographs that we could have shown, but on the side of the vessel you will see kind of a swath of corrosion products coming down the side of the --

MEMBER WALLIS: Doesn't that represent a leak to you?

MR. GROBE: Well, that's the issue.

MEMBER WALLIS: What else could it be?

MR. GROBE: Well, it came down, as I said, on the side of the vessel. On the side of the vessel you will see a swath of corrosion products that have come down the vessel. As I mentioned, this is in the center of the bottom of the head. So they all come to a convergence there.

MEMBER WALLIS: Then they run down this tube or something?

MR. GROBE: Yes. That's correct. That is clearly part of what happened.

Also, there's a number of other penetrations that have corrosion products on them. Wherever a penetration intersected the material that was coming down the head, it would run down the penetration.

FirstEnergy was not satisfied with the simple answer that --

MEMBER WALLIS: Why is it drawn to the penetration?

MR. GROBE: It is simply gravity. It wasn't drawn to the penetration; it was running down the vessel. As it intersected a penetration, it run down the penetration.

MEMBER KRESS: It lost part of the head.

MR. GROBE: Yes. I'm sorry, let me repeat. This is the penetration that is in the center of the bottom of the head. So it's the lowest point on the head.

FirstEnergy was not satisfied with the easy answer, that this was simply corrosion that had come down the head or had come down from the head. They did chemical analyses, comparisons of this material to the sides of the head, to the top of the head, to the sides of the vessel and the top of the head. That chemical analysis was inconclusive.

So what they have concluded, what they have determined is an acceptable thing to do, and presented this to us last week in a public meeting here in Headquarters, is to do a pressure test where they've cleaned the entire head, they're going to take the reactor coolant system up to normal operating temperature and pressure, keep it there for a period of time, shut down, cool down, and then do a thorough inspection of the bottom head. If there are through-wall cracks, they will be evident from boric acid leakage.

MEMBER SIEBER: That means they have to clean all this off?

MR. GROBE: It's already been cleaned.

MEMBER SIEBER: Okay.

MR. GROBE: Yes, this is a photograph before it was cleaned.

MEMBER SIEBER: And on the pressure test anything that leaks will immediately evaporate. So you are really looking for residue again.

MR. GROBE: Exactly, and very, very small leaks will result in easily-observable residue.

MEMBER LEITCH: Was there any degradation of the material as a result of that boric acid running down there?

MR. GROBE: No. There was no observed degradation to the vessel metal.

MEMBER LEITCH: Okay.

MR. GROBE: Let's get into the next slide.

Prior to this outage, the Davis-Besse sump had approximately a 50-square-foot surface area screen. That is characteristic of operating pressurized water reactors. There were a number of deficiencies with the screen, including the mesh size was incorrect. It wasn't in accordance with design. There were some gaps in the mesh.

There were some non-permanent modifications. What I mean by that is there were some gaps low in the mesh, and they simply stacked lead bricks in front of the gaps.

The licensee has concluded that during this outage they will substantially expand the surface area of the screen to approximately 1200 square feet.

In this picture, this is the sump here. This is the concrete structure that supports and contains the reactor vessel itself. This is the location of the original screen, which was approximately 50 square feet. That is being replaced.

In addition, there's holes being punched in the side of the sump. This plenum is being installed, and then perforated pipe is being installed down this staircase. This is the staircase that goes into the in-core under-vessel area, and another plenum with additional perforated pipe coming off of that second plenum. This will substantially increase the surface area, the suction surface area, for the sump screen.

MEMBER WALLIS: Why is this being done?

MR. GROBE: It is being done right now.

MEMBER WALLIS: But why? Is it being done because they found deposits on the screen or the screen was blocked or there was a lot of junk down there, or what?

MR. GROBE: I believe it is being done for a couple of reasons. One is they are in extended outage. The screen had deficiencies with it. Instead of replacing it with the same type of design, they decided to --

MEMBER WALLIS: But this is a tremendous change. It is a change in area of 24 times.

MR. GROBE: That's correct.

MEMBER WALLIS: So this must indicate that there was some real reason to do this work.

MEMBER KRESS: It has to do with the blockage of the screen due --

MEMBER POWERS: The large-break LOCA.

MEMBER KRESS: -- large-break LOCA.

MEMBER WALLIS: It's like the flakes coming off the containment walls, for instance?

MEMBER KRESS: Yes.

MEMBER POWERS: Insulation mostly.

MEMBER WALLIS: Yes, right.

MR. GROBE: Let's move along. This next photograph, this is actually right next to the sump there's a pit. The original design of the plant was that there's two suction valves. The decay heat removal system suction valves are in this inside containment. The original design was that those should be submersible, qualified operators on those valves. When the plant was constructed, they were not submersible qualified.

To address that issue, the company chose to seal the pit. See, this RTV. It was a very difficult job to seal all of the openings at the top of this pit. They simply used gobs of RTV to accomplish that.

The company has chosen to engineer a solution to this. Submersible operators are not available. So they're lining the pit with stainless steel. They're going to put a stainless steel cap on it, and then gasketed and bolted openings in that cap.

This is a photograph on the next slide, that's actually the side of the reactor pressure vessel. It was a non-qualified coating on five large vessels, the reactor vessel and the four core flood tanks, as well as coating problems on conduit, a substantial number of square feet of coatings on conduit where they applied the coating right over the galvanized conduit without a primer. In addition to that, there were coatings issues on the containment walls and the dome.

MEMBER WALLIS: Does this have anything to do with the event that initiated this whole thing?

MR. GROBE: No.

MEMBER WALLIS: So this is something else which was a problem which had not been fixed?

MR. GROBE: That's correct. These are issues that the company identified during the course of doing their comprehensive inspections inside containment, and they're fixing these.

MEMBER SIEBER: I have a question about the coating on the reactor vessel. The reactor vessel sits inside the neutron field tank, right?

MR. GROBE: It sits -- I'm sorry?

MEMBER SIEBER: Inside the neutron field tank?

MR. GROBE: It sits inside a concrete structure, but there's no liquid on the outside of it.

MEMBER SIEBER: Okay. Is it accessible?

MR. GROBE: I'm not certain that this is going to be replaced.

MEMBER SIEBER: Oh, okay.

MR. GROBE: Pat, do you have the specifics on this specific location? The core flood tanks have been cleaned and --

MR. McCLOSKEY: Yes, the core flood tanks -- any of the unqualified coatings on the large vessels have been removed, and plans are either to analyze them and remain uncoated, which we believe a lot of the vessels should have been and could have been. The reactor vessel itself probably did not require this coating.

The description of where it is located, it is located within the concrete shielding as well as behind significant vessel insulation as well. This would have been our first opportunity since the operation of the facility to actually see this side, since the under vessel and its side vessel is not routinely inspected.

So the determination was made at the point in time that, while we're addressing coatings, remove that and assess that. My belief is that we will not reinstall that coating over the carbon steel.

MR. GROBE: This has been hydrolased. It's been cleaned, but it is not going to be recoated.

MEMBER SIEBER: Okay. So the coating is gone now, because that looks like a sump clogger to me.

MR. McCLOSKEY: Exactly.

MR. GROBE: Exactly.

MEMBER SIEBER: All right, thank you.

MR. GROBE: In conclusion, our oversight activities are well underway. They are well organized with a checklist, and our focus is good.

FirstEnergy's restart activities are well underway, and they are showing progress. We have a number of performance goals. There's one other document that I gave you, and that's part of our performance goals are to ensure that the public has confidence that the NRC is a strong and credible regulator. We continue to have a large amount of interest both from members of the public as well as elected officials.

I gave you another document that looks like this. It is just for your reading pleasure. We are issuing monthly updates or newsletters on activities that are ongoing. This is a continuing activity that we have to try to ensure that the public is well-informed and, hopefully, retains that confidence in a strong and credible regulator.

That completes my 15-minute presentation.

(Laughter.)

MEMBER FORD: Jack, thank you very much.

I am assuming that there are no other major questions. I am also assuming that you will be coming back to us again --

MR. GROBE: Whenever you would like.

MEMBER FORD: -- with more time available for this important subject.

Art, I turn it over to you. We do have an extension of 15 minutes to this section. So there is a little bit of time up for you. So we will be finishing this at half past 10:00.

MR. HOWELL: Thank you. My name is Art Howell. I'm from the Region IV Office in Arlington, Texas. I also served as the Team Leader for the NRC's Davis-Besse Reactor Vessel Head Degradation Lessons Learned Task Force.

Before I go any further, I would like to recognize there are two Task Force members in the audience, Tom Koshy from NRR and Joe Donoghue, also from NRR.

What we would like to do today is provide an overview of our report, which was already issued back in October. It was made publicly available on the 9th, I believe.

Skip two slides, not the next slide, but the slide after that one.

Dr. Hackett, who is our Assistant Team Leader, briefed the Committee on June 5th and 6th on the charter. I just wanted to take a moment to touch on those items, just to refresh folks' memories.

The purpose of the Task Force was to conduct an independent evaluation, primarily a retrospective look at our regulatory processes, to identify recommendations for NRC and industry improvement.

The charter had five broad areas. Obviously, within these five areas we looked in detail at a number of specific processes and programs.

For example, in the reactor oversight process, we obviously looked at the inspection program and implementation at Davis-Besse. We looked at the plant performance assessment process.

We reviewed enforcement history. We also reviewed enforcement history broadly across the board generically in terms of enforcement actions involving primary system leakage and boric acid corrosion. We reviewed the allegation history, not only at Davis-

Besse, but for the other FirstEnergy plants, going back some 12 years.

The next slide, please. In terms of the team composition, it was a multi-discipline team. There was 10 of us total, including our Administrative Assistant. We had representatives from Region IV, Region II, NMSS, NRR, and Research.

An experienced team; we had both current and former Senior Resident Inspectors at other Babcock & Wilcox designed plants. We had Regional Supervisors, Senior Licensing Project Managers, and Senior Operations Engineers on the team. None of us had any significant previous involvement with Davis-Besse in terms of inspection, enforcement, licensing.

We had a formal agreement with the State of Ohio. They provided one observer to the team. She primarily spent her time with us at Davis-Besse during the fact-finding there. She also spent some time with us here in Headquarters during the assessment phase.

We conducted two public meetings to solicit input on our charter. One was near the plant back in June, and the other one was here in Headquarters, also in June. We did receive input, and we factored that input into our detailed review plans.

Next slide. In terms of review methods,

we used processes and techniques that were similar to those used in past NRC incident investigation team and diagnostic evaluation team reviews. This included the construction of detailed review plans. We also had prescripted interview questions for a number of folks that we pre-identified to be interviewed. We formally tracked our observations and interviews, and we also used various root cause analysis techniques to sift through all the data.

The team was broken down into two groups. One primarily spent its time reviewing processes here in Headquarters. The second was fact-finding at Davis-Besse and the regions.

I just want to make it clear, we conducted review activities at all four regions, either telephonically or in person. It wasn't just in Region III.

We, obviously, conducted document reviews and interviewed personnel. I think somewhere on the order of 100 NRC personnel were interviewed, about 40 or 50 Davis-Besse personnel, and we had 10 others from various industry organizations, as well as French regulators.

We were at Davis-Besse for a number of periods during the summer to collect data. As I mentioned, we were conducting reviews in all four regions.

MEMBER FORD: Obviously, there's a fair amount of overlap with the group that Jack was heading. How did that take place, the communications? Is it informal, formal communications?

MR. HOWELL: One of our charter elements was to coordinate with the other reviews. So there were periods during the summer in which the Task Force provided in-progress status reports to Jack in person, to the 0350 Panel, plus other ongoing reviews that were in progress.

So, at the end, near the end of it, we also provided background and clarified any questions that we had on any of the Davis-Besse plant-specific issues that are documented in Section 32 of the report.

MEMBER FORD: Okay, but just enlighten us all. You're far more specific on Davis-Besse, you're specific on Davis-Besse as it applies to the rest of the industry and how the NRC regulates --

MR. HOWELL: Correct.

MEMBER FORD: -- as a whole?

MR. HOWELL: Correct.

MEMBER FORD: Not just Davis-Besse?

MR. HOWELL: Now you will see in our report there is one section of our report that deals entirely with Davis-Besse plant-specific issues.

MEMBER FORD: Right.

MR. HOWELL: And those were coordinated with Jack and the Oversight Panel.

MEMBER FORD: Okay, good.

MR. HOWELL: The next slide on reports. It is just to indicate where you can find the report, either in ADAMS or on the web page. As I just mentioned, there was coordination with plant-specific issues.

MR. GROBE: It is on the web page. So you can find it.

MEMBER POWERS: He didn't put the clause "easily" in there. He just he could find it.

(Laughter.)

MR. HOWELL: It is conceptually possible to find it.

(Laughter.)

Next slide. Overall conclusions: Fundamentally, we concluded that the industry and the NRC recognized the potential for the Davis-Besse event some 10 years ago, following the identification of cracking at the French plant Bugey in 1991.

This type of event was analyzed, and it was concluded that, although there was a potential for corrosive attack of the head, that the leak would be detected long before any significant corrosion would occur. This was predicated on the notion that the identified leaks would likely be axial in nature, wouldn't result in a catastrophic failure of the nozzles. Therefore, any ensuing corrosion from the leaking primary coolant would be detected by boric acid corrosion walkdowns under the General Letter 88-05 program.

There was some recognition that some small percentage of small leaks would not be detected. So there was some discussion back in the early nineties about the insulation of enhanced leakage detection systems and the efficacy of those systems. That system, obviously, is not installed at Davis-Besse or elsewhere.

In addition, we identified that the NRC and Davis-Besse failed to learn key lessons from past boric acid-induced degradation events. Specifically, the one that is important is that there were a number of events, if you look at the raw operational data, if you look at some of the events that have been captured by generic communications in the past, there are a number of events where there were primary leaks in which corrosion rates were underpredicted and, therefore, the damage was more significant than what was expected.

This is important because what we found, not only at Davis-Besse, but elsewhere, is that there has been a tendency, at least at many places, where these leaks are actually identified, then there are some conscious decisions being made to defer the repair of these leaks because of the underlying assumption that the corrosion rates will be insignificant. So in some cases these deferrals have lasted more than a year until the next refueling outage.

VICE CHAIRMAN BONACA: Now in other countries, like France, they took a different path, right?

MR. HOWELL: Correct.

VICE CHAIRMAN BONACA: So you will talk about that experience later on?

MR. HOWELL: Yes, yes.

VICE CHAIRMAN BONACA: And was there sufficient comparison of these decisions by the NRC, by the industry? I mean, was this evaluated as a significant input, the fact that in countries like

France that took a completely different direction in that sense, and they decided that they would have volumetric inspections, prevent leakage, and then, ultimately, that led to replacing the heads much ahead of time?

MR. HOWELL: Right. I was going to address that in a couple of minutes, if that's sufficient.

VICE CHAIRMAN BONACA: Okay, you will? That's fine.

MR. HOWELL: Fundamentally, the Task Force was focused on understanding why the event wasn't prevented. So, therefore, it was more of a retrospective look. That explains why, for example, we didn't touch on things about the ongoing significance determination process, reviews, and things of that nature that were post-discovery.

We concluded primarily that there were three main contributing causes. They are here, and I am going to go through each one of these in detail in the succeeding slides, but --

MEMBER FORD: Excuse me. You are going to go through these in detail?

MR. HOWELL: Yes, in turn, right. Then there's a number of subelements under each of these.

MEMBER FORD: Okay, good.

MR. HOWELL: So I won't spend any time here.

Next slide. We also found some --

MEMBER WALLIS: I just noticed, I have to notice that you have "NRC failed" for something just as frequently as you have "DBNPS failed" to do something in your slides. The statement the "NRC failed" to do something occurs just as frequently as the statement "DBNPS failed" to do something. I just can't help pointing that out.

MEMBER FORD: And the reason for that will be discussed in a minute?

MR. HOWELL: Yes.

CHAIRMAN APOSTOLAKIS: But if I were to select one bullet of all of these and say, well, boy, this was really the problem, I mean, I would be inclined to select the second bullet on slide 7. Would I be wrong?

MR. HOWELL: No. I mean I think, clearly, fundamentally, the primary responsibility rested with the licensee to --

CHAIRMAN APOSTOLAKIS: The previous slide, Sherry.

MR. HOWELL: -- to have either prevented

or detected this issue in its incipient phases much earlier.

CHAIRMAN APOSTOLAKIS: Yes. The judgment, I think, was not an immediate safety concern. Is that the No. 1 problem? No? What was it? I mean, they knew about it. They didn't know about it?

MR. HOWELL: Well, they didn't know or recognize that the nozzle itself was leaking.

CHAIRMAN APOSTOLAKIS: But it seems to me that the issue that is not --

MR. HOWELL: I'm not saying they shouldn't have known, but I'm saying --

CHAIRMAN APOSTOLAKIS: Right. Let's clear it up because --

VICE CHAIRMAN BONACA: Well, the fact that they decided it was an immediate safety concern, I think we all could agree with that conclusion. The word "immediate" is important.

CHAIRMAN APOSTOLAKIS: Right.

VICE CHAIRMAN BONACA: If it isn't immediate, but it could be a future safety concern. So how come -- I'm trying to understand, you know, I mean personally, how come we protracted these inspections? How come we made the decisions that led to waiting for circumferential cracks before we took some actions there?

It seems to me that is an important thought process that took place in the industry and the NRC versus the thought processes that took place in other countries. I quoted France because we just compared with them our experience recently, and there is a significant divergence there. So I am trying to understand how we got there.

MR. HOWELL: Well, based on our review, I mean, clearly, if you look back to the early nineties and you look before then into the eighties, you will see that most of the instances of identified nozzle cracking -- and I'm not just talking about VHPs; I'm talking about other instrument nozzles in the reactor coolant system -- virtually all of them were axial.

Now what we found was that the condition identified at Bugey both involved axial and circumferential cracking. Some of that was communicated back in the early nineties to the staff, but perhaps not, well, in fact, not all the details were well-recognized or understood. That may have been a contributing factor as to why the potential for circumferential cracking was not emphasized at that time.

So, clearly, there was a mindset in the

early nineties that nozzle cracking would be axial, that this axial cracking would not result in catastrophic failure of the nozzles, that any leaks that ensued would be detected in due time before significant degradation.

As a result of that, further work became protracted. I mean, there was work by the industry to perform some pilot, non-visual examinations at plants in the mid-nineties, continuing reviews by the staff. This continued on, and before you know it 10 years elapsed before the Oconee experience.

CHAIRMAN APOSTOLAKIS: So that would seem to be a key element.

MR. HOWELL: It is a key element. So that's why we highlighted it upfront.

MEMBER SIEBER: But the emphasis has always been on cracking as opposed to corrosion of the ferritic material.

MR. HOWELL: Right.

MEMBER SIEBER: And I don't think that anybody realized that the extent of corrosion that did occur would occur until the day this Besse situation arose.

MR. HOWELL: The extent that it could occur was realized. It was believed that it would not occur because it would be detected long before there was significant degradation.

VICE CHAIRMAN BONACA: Well, how would it be detected?

MR. HOWELL: By visual exams during outages.

CHAIRMAN APOSTOLAKIS: Which were not taking place.

MR. HOWELL: Or inadequate, whatever, not comprehensive, yes.

CHAIRMAN APOSTOLAKIS: Sure.

MR. HOWELL: And that was one of the underlying notions that was not verified. That assumption was not verified because, in reality, what was happening is that this was a voluntary program that was being implemented by licensees, and it was not being inspected by the NRC. There was no independent verification by us that these programs were effective over the course of 10 years.

CHAIRMAN APOSTOLAKIS: Now what was the role of our inspectors there?

MR. HOWELL: Well, I was going to get to that.

CHAIRMAN APOSTOLAKIS: Okay, okay.

MR. HOWELL: If you are on slide 7 still, that's the third bullet there. We collectively, the NRC, knew about some of the symptoms and indications of the reactor coolant system unidentified leakage. So I'm clear, not about the nozzle leakage, obviously, but about ongoing, unidentified RCS leakage.

There was also some knowledge about boric acid deposits on the head during the 2000 refueling outage timeframe.

CHAIRMAN APOSTOLAKIS: Now further reviews became protracted. Not only the reviews, but I mean there were decisions made, as Jack told us earlier, to ease the access to the top of the head, so that inspection would take place, and that was postponed for a number of years, right?

MR. HOWELL: Correct.

CHAIRMAN APOSTOLAKIS: I'm just curious, the Safety Board, they must have a visiting Safety Board.

MR. HOWELL: They do.

CHAIRMAN APOSTOLAKIS: Or the INPO guys --

MR. HOWELL: They do.

CHAIRMAN APOSTOLAKIS: Nobody noticed that and asked, "Why are you doing this?" or everybody says, "Well, that's okay."?

MR. HOWELL: I can only tell you what the record indicates. With respect to the Safety Board, there was, in the 2001 timeframe, there was discussion between the Safety Board and the plant staff that there was obviously active reactor coolant system leakage that was ongoing, and it had not been identified, and --

CHAIRMAN APOSTOLAKIS: Yes.

MR. HOWELL: -- that the efforts to date had not been successful in identifying that leak. That's about as far as we could piece together the story there.

I mean, it was obvious that there was ongoing leakage that had been identified.

CHAIRMAN APOSTOLAKIS: Yes.

MR. HOWELL: Then, in terms of other third party reviews, clearly, a message was sent that they had a chronic problem with not fixing known primary system leaks. That was documented in reviews that were conducted in the 1997-98 timeframe.

There was also some documentation, both by the NRC and INPO, regarding a particularly egregious leak involving the pressurizer spray valve that ate away some of the fasteners because carbon steel fasteners were replaced instead of stainless steel fasteners.

CHAIRMAN APOSTOLAKIS: There were two things here then. One is the actual performance-based failure to do something, like they were losing inventory. But the second, you know, the mere fact that they were deferring this action from year to year, I mean, even if they were not losing inventory, shouldn't somebody ask the question, "Why?" Why did they decide to -- how many years did they defer it? For 10 years?

MR. HOWELL: Eleven years. Actually, it was deferred once again. If you count it all up, it wasn't going to be installed until 2004. So it would have been 13 years.

CHAIRMAN APOSTOLAKIS: Thirteen years, and nobody asked, you know, "Why are we doing this for 13 years," deferring it from year to year to year?

MR. HOWELL: Well, it was deferred. Actually, it was closed at one point and then reopened again because of the ongoing nature of the problem, and then deferred again subsequently.

We interviewed members, some of the members, who were involved in that decision. Those members, their view was that this was not an immediate safety issue. They realized that there was boric acid on the head, but it had been on the head for quite some time, and they hadn't identified any significant degradation.

CHAIRMAN APOSTOLAKIS: Let me understand the meaning of the word "immediate." If something is not immediately a safety concern in 1991, so we'll do something about it in the future. Then in the year 2001 we still say it is not an immediate safety concern? That means it is never going to be an immediate safety concern, right?

It's like the fusion thing; every day it's 50 years from now. Time doesn't seem to flow. I mean, 20 years ago fusion was going to be a reality 50 years from that time. Now it's 50 years from today.

So it is not an immediate concern, and that statement is independent of time. That's essentially what you are saying. You can say that anytime and defer -- I mean, I'm not blaming you, obviously.

MR. HOWELL: No, I understand.

CHAIRMAN APOSTOLAKIS: I'm trying to understand what the word "immediate" means.

MEMBER WALLIS: Well, global warming is a better example than fusion, I think.

(Laughter.)

CHAIRMAN APOSTOLAKIS: I'll use that next time.

MEMBER SHACK: How many B&W plants made the modification that was needed so that they could look at everything?

MR. HOWELL: I need to answer that in two parts because they implemented these modifications over time.

MEMBER SHACK: Right.

MR. HOWELL: At the time that some of the deferrals were going on Davis-Besse, I believe that there was at least one other B&W plant that had not, at that time during this 10-year timeline, 13-year timeline, at that point in the late nineties, had not made the modification yet. I understand now that that modification has subsequently been performed.

MEMBER SHACK: So by the late nineties all but two had made the modification?

MR. HOWELL: That's my understanding, yes.

CHAIRMAN APOSTOLAKIS: What does that mean? What do I learn on that?

MEMBER SHACK: Well, that they could at least follow the requirement that they were able to see what was happening.

CHAIRMAN APOSTOLAKIS: Who is "they?"

VICE CHAIRMAN BONACA: The licensees.

MEMBER SHACK: The licensees.

VICE CHAIRMAN BONACA: The other licensees.

CHAIRMAN APOSTOLAKIS: No, but what does it mean for Davis-Besse? You know, the years pass. We recognized at the beginning it was not an immediate safety concern, and other licensees are doing it, and we still say, no, it's not immediate. What does that mean?

VICE CHAIRMAN BONACA: It seems to me that it means the requirement should have been there, it seems to me, not a voluntary initiative, but realizing that it is not an immediate safety concern, you then say, however, it may be a future safety concern, and therefore, the inspection is required, is a needed thing to do. Therefore, at some point some modifications had to be done to be able to inspect.

I mean, it has to be --

MR. HOWELL: We made a recommendation to address that very point.

MEMBER SHACK: Wouldn't the Boric Acid Corrosion Program under the Generic Letter say that you have to be able to inspect that?

MR. HOWELL: Yes.

MEMBER SHACK: So they were in violation?

MR. HOWELL: Clearly, the intent was that they inspect it. There was no detailed guidance in the procedures to perform a head inspection, but the intent was there. The intent was to identify all potential leakage sources and inspect them.

MR. GROBE: The licensees themselves specifically identified that they could not implement their procedure for the head because they could not thoroughly inspect and clean all areas of the head, and wrote that up in the CR, in the Condition Report. That's why their failure to implement these modifications was a violation.

CHAIRMAN APOSTOLAKIS: Now when the other plants actually implemented, did they find anything that was worth communicating to Davis-Besse, that maybe the statement that it is not an immediate safety concern is not very valid anymore? Did they find anything? Did they find any cracks that were unusual or anything or did they just --

MR. HOWELL: There have been cracks at all the other B&W plants, as of late 2001. So we have to be clear about the time period.

CHAIRMAN APOSTOLAKIS: Yes.

MEMBER SHACK: Nobody else found hundreds of pounds of boric acid though.

MR. HOWELL: True. Right.

CHAIRMAN APOSTOLAKIS: Did they find circumferential cracks?

MR. HOWELL: Yes.

MR. GROBE: Not during the timeframe that these decisions on deferral were to be made.

MR. HOWELL: Right, right. This was late in the game, you know, 2001.

MEMBER FORD: Could I return to the immediate question that we had on that slide there? In your conclusions you made the recommendation, you make the correct observation we should take more account of what is happening overseas, France.

MR. HOWELL: Yes.

MEMBER FORD: When you were discussing this immediate aspect, did it never occur to anybody that the French were at least seven-eight years in front of us in terms of coming up with remedial actions, changing their tech. specs. for leakage rates, et cetera? Did no one here within the NRC or within our industry in this country wonder why the French were doing this, and they had exactly the same phenomena, starting with Bugey and then a whole lot of other reactors?

MR. HOWELL: We explored that. Of course, we talked to a number of folks here on the staff. We also talked to some French regulators. We got a range of views. Some were under the impression that their corrective actions were largely economic in nature.

MEMBER FORD: The French --

MR. HOWELL: Yes, in terms of head replacements, and that there's others who, at least until the Davis-Besse event, would have told you prior to that point that they thought that the French corrective actions were an overreaction because of the belief that there would be axial cracking and that these would be detected, these leaks would be detected in time.

MEMBER FORD: But they had circumferential cracks?

MR. HOWELL: Correct, and the extent of staff awareness of the Bugey circumferential cracking was not widespread. Part of that may be, I think at least in part, the manner in which this information is shared with us, how much we knew, how much was provided, how was it was internally disseminated.

It was a number of years ago; there's staff turnover. There's a lot of reasons for it, but there was some awareness, but it didn't translate into any action in terms of addressing circumferential cracking by means of generic communications until the Oconee event.

MEMBER FORD: It wasn't pure insularity?

MR. HOWELL: Right. Now there was some mention of circumferential cracking in Generic Letter 97-01. So there clearly was some recognition, but, again, the predominant view was, and operating experience indicated, that axial cracking was predominant --

MEMBER FORD: I must admit we're jumping the gun a little bit, and I'm sure you may come to it. In your recommendation you say you should take into account other experience, worldwide experience. How are you going to accomplish that?

MR. HOWELL: Well, we had a program and we actually do have a program. What we are saying is that there are some changes to the processes by which we obtain and internally assess and disseminate foreign operating experience back in the 1999 timeframe, and what we are recommending is that we assess the whole operating experience review program and look at that particular aspect to make sure that it is functioning well.

Slide 8, overall conclusions: There were some other contributing factors. Guidance and requirements, I am going to talk about these as well; staffing and resources; EVS communications, that's really written communications primarily, and licensing processes and implementation of those processes.

Next slide. Okay, with respect to the NRC and industry review and assessment, and followup of operating experiences, there are a number of topical areas in the report that are addressed.

I want to start out by saying that the Task Force conducted its own independent assessment of the reported data on primary system leakage from 1996, I mean 1986, all the way up to the time of the Davis-Besse event. So that covered about 16 years.

So we looked at LERs, Licensee Event Reports, as our source of data. We analyzed this data. What we found is that there are many, many boric acid corrosion events, many nozzle leakage events. Obviously, none of the nozzle leakage events were not -- did not result in a degradation to the same degree that occurred at Davis-Besse, but, nevertheless, there were a number of reported events involving instrument nozzles primarily and pressurizer heater sleeves.

What we found is that essentially there's two plants, two types of plants, NSSS designs that are outliers, B&W and Combustion Engineering, in terms of the total number of events.

A lot of this information was known by the industry and the staff. It resulted in, since 1986, 17 separate generic communications by the NRC. I think there was a similar number from INPO. Yet, in spite of that, this event still occurred. So the question is, why? Why didn't the process serve as a catalyst to ensure that something this bad didn't happen?

What we found was that there's a number of issues here, but some of the relevant information was perhaps not known. You can see that when you analyze the data, that there was gaps in periods where there were events being reported about instrument nozzle leaks, for example, at CE plants, and there was no generic communication that occurred during that period.

But, also, we found that one of the things that we hadn't done well as an agency was to independently verify that these programs were being effectively implemented, specifically with respect to the Boric Acid Corrosion Program that is governed by Generic Letter 88-05. We had an inspection procedure, but it was a voluntary inspection procedure. It was never implemented at Davis-Besse, and it was rarely implemented nationwide at the other plants.

So we never verified the underlying assumption that these types of programs would be effective in identifying nozzle leaks in a timely manner to prevent significant degradation of the head.

Similarly with Generic Letter 97-01 on axial cracking of vessel head penetration nozzles, there was no independent verification of those activities by the staff.

So there's a number of issues with the implementation of the Generic Communications Program. So it's a mixed story. We knew a lot. We put out a lot to the industry. Yet, in spite of that, there's some things that either we didn't fully appreciate or fully assess or didn't take action on to verify.

Generic Issues Program, there was no generic issue previously identified for either boric acid corrosion solely. There was one in the early eighties that pertained in part to boric acid corrosion in fasteners, stemming from an event at Fort Calhoun station, nor was there one that pertained to stress corrosion cracking of nozzles.

With respect to the operating experience, we pulsed a number of countries. We got some good, had good exchange with the French that provided some information as to the basis for some of the French decisions about corrective action.

What they essentially told us was that at the time of the Bugey experience that they recognized the potential for two failure modes, catastrophic failure of the nozzle from circumferential cracking and also significant degradation of the vessel head from a leaking nozzle. That is why they embarked on the course of action they did in terms of mandating non-visual examinations of the penetrations.

It was difficult for us to piece together how much of that was known or recognized by the staff. Again, there was a range of views about why the corrective actions were what they were pertaining to the French reactors.

MEMBER WALLIS: Once someone had decided that it didn't apply to us, then, presumably, the interest in Bugey was dropped? That may have been 10 years ago?

MR. HOWELL: Well, yes, if I can expand on that, there was some further review. There was a NUREG published in the mid-nineties timeframe that did some comparisons between French operating experience versus experience -- I believe the plant may have been

Point Beach -- at one U.S. plant. There was a number of differences identified. It was on the basis of those differences that reinforced the notion that it wasn't a problem with U.S. reactors at that time. That is pretty clear from reading that NUREG.

MEMBER FORD: Back in July of last year, at the ACRS meeting, we asked a very specific question: Why we weren't taking into account -- this is last year -- into account the foreign experiences, specifically French? The answer we had was, hey, the French operate their reactors, they also design their reactors, in a completely different way to ours, and therefore, their experience is of little value. Do you still have that opinion?

MR. HOWELL: Well --

MEMBER FORD: This was the opinion given by the utilities.

MR. HOWELL: I mean, there are --

MEMBER FORD: I'm sorry, the operators, the OEMs.

MR. HOWELL: Well, clearly, there are some differences, but, ultimately, there was stress corrosion cracking there and here. So we need to appreciate that. There were some similarities, too, in our view. So it would be hard for me to agree with that notion that all these differences would explain, with the benefit of hindsight, why more action wasn't taken.

Now, having said that, action was being taken. It was just protracted. I mean, there's a clear recognition that circumferential cracking could occur, and then if it did, it needed to be looked at, because that was a serious issue.

In terms of assessment and verification of industry technical information, I mentioned one, but, essentially, in the early nineties, when the conclusion was made that these leaks would be detected in a timely manner, there were some fundamental assumptions that essentially weren't verified.

First and foremost was the Generic Letter 88-05 programs, their implementation effectiveness had never been verified. I won't say never. Had not, typically, routinely been verified at the time.

Also, there was some, at least for the B&W plants, there was some expectations that enhanced visual inspections of the vessel heads would be conducted because of the design of the CRDMs with the flanges and the history of the leaking flanges and the fact that boric acid deposits from the leaking flanges could be deposited on top of the head.

Yet, these enhanced visual inspections were not conducted at Davis-Besse. There was no verification of that.

There was also a belief that undetected leaks would not be significant in terms of degradation in one cycle. If you had an incipient failure that wasn't detected at the start of or during the refueling outage, and then became a leak at the start of an operating cycle, the view was that such a leak would not result in significant degradation.

It is not clear to the Task Force how much was known about the different tests and experiments that were conducted to identify what these corrosion rates could be. What we found is that on the high end that these corrosion rates could be in excess of 4 inches per year.

So at Davis-Besse they have a two-year operating cycle. So you could have significant degradation in one or two cycles, which I believe is what occurred.

Then, finally, the last bullet there is an acknowledgment that in 1999, when the Office of AOD was dismantled and its functions were distributed to the other office, there were some significant changes to the processes in which the agency reviews industry operating experience.

The reason I bring this up is that, prior to that reorganization, there were some reviews, assessments done of the agency's operating experience review programs, but they were primarily focused on efficiency. So we looked at this, and the Task Force believes that, given all the changes that have occurred in that program and how much of this relates to the Davis-Besse event, that one of our recommendations was to go back and do an effectiveness review of our entire program in that area.

Next slide, please.

MEMBER POWERS: The previous slide, which I really don't need to see, delineates a set of plausibility arguments that were advanced at various points in time, plausibility that the French experience doesn't apply, plausibility the corrosion rates are not excessive, and things like that.

Those kinds of arguments appear in front of this Committee a lot, and whatnot. Based on what you are finding, is there any generic advice that can be formulated considering plausibility arguments?

MR. HOWELL: Well, to answer your question, of course, we looked only at Davis-Besse. We did some limited benchmarking at two other B&W

plants to try to get some sense for how these programs were implemented there.

But one of the reasons we looked at operating experience holistically as it relates to these two technical issues was to get some generic sense for how well the industry was doing relative to these two areas. On that basis, we felt that to get a better handle on just how well these plausibility arguments, as you indicated, are being implemented, that perhaps we ought to go back and review a sample of other generic issues that past actions have been identified and supposedly taken, to get some sense for how well the implementation effectiveness is being addressed.

MEMBER POWERS: I understand.

The Committee members will note that I think on Friday we are going to listen to a protracted plausibility argument concerning the quality of PRAs and want to bear in mind the adequacy of plausibility arguments.

MR. HOWELL: The next slide. With respect to contributing factors involving Davis-Besse performance, we have five major areas that are documented in the report.

The first one, reactor coolant system

leakage symptoms and indications, this has been discussed by Jack and others. The licensee failed to promptly identify and correct known leaks, not only with CRDM flanges, but also primary system valves, and also reactor coolant system instrument thermal welds over a long period of time.

We also identified that there was a pattern of behavior in which the symptoms of this leakage in terms of fouling of containment air radiation monitors and the containment air coolers was the licensee's primary focus, was to address the symptoms. What was absent was objective, rigorous information to support activities to get to the root of the problem, either through the root causes analyses of the various condition reports that had been written over the years or during outages, when there was an opportunity to actually identify the leak sources.

In terms of the Boric Acid Corrosion Control Program and implementation, I don't want to rehash what's been covered, but we found that the program, or at least we concluded that the program was both inadequate and was not implemented as written.

Owners' group and industry guidance in some cases was not followed at the plant. This pertains to enhanced visual inspections. Other guidance put out by various industry groups, EPRI and the B&W Owners Group, were either not verified to be implemented -- there was no mechanisms at the site to ensure that these actions would be implemented.

Some of the guidance, arguably, is incomplete. So there were some contributions to the lack of identification of the problem in that.

Internal and external operating experience awareness, there were numerous other boric acid corrosion events involving plant components at Davis-Besse. One of them, in particular, involved the pressurizer spray valve. This leaking valve was identified in 1998. It was the subject of a special inspection by the NRC in 1999.

The lessons learned for that event I think, with one possible exception, are the same lessons learned for the RPV head event. So one has to ask why the actions weren't effective.

What we found was that some of the identified actions were not fully implemented, and, arguably, some of the identified actions were not timely.

VICE CHAIRMAN BONACA: Do you find indications of differing opinions within the Davis-

Besse organization regarding decisions not to inspect the head or postpone the inspections?

MR. HOWELL: I'm trying to just mentally sort through all the interviews we conducted. What we found was, that there was a varying level of -- there was a difference in view about the status of head-cleaning activities at the plant.

What we found was that a number of managers and engineers and others clearly knew that the plant was being restarted from successive refueling outages with large boric acid deposits on the head. Others believed that the head, especially by the 2000 timeframe, had been completed cleaned. In part, we think that to be the case because of some of the internal documents that Jack made reference to that were available to the staff, to the licensee staff, for review.

So is that responsive? I mean, that's what we found.

VICE CHAIRMAN BONACA: I'm just wondering, I mean, if everybody within the Davis-Besse organization agreed that there was no concern and they could restart, or was there somebody who raised issues regarding, for example, the clogging of the filters and things of that kind? Was there any record of that?

We are talking about safety culture, and I think it is --

MR. HOWELL: Right. As Jack alluded to, there were a number of individuals involved in head-cleaning activities that were concerned, clearly, that the program procedure could not be implemented, that there were deposits on the head. There were others who believed that -- and this goes back to one of the past lessons that wasn't learned -- was that these deposits would be dry deposits.

They wouldn't be highly corrosive. They've been there for a while. They haven't caused a problem yet and are not likely to cause a problem other than some operational problems with the rad monitors or the containment air coolers, which were, at least in their view, being addressed.

So, yes, some thought that the head needed to be thoroughly clean and inspected. Others thought that, yes, they are going to do as much as they can, given the design of the service structure, but, by and large, these deposits would not be harmful.

Then the last bullet is oversight of safety-related activities. What we found in the areas that we reviewed, we found implementation problems in a number of areas. I will just go through these real quickly:

Inappropriate focus on production; accepting longstanding problems; lack of management involvement, questioning attitude; lack of management involvement, head-cleaning activities; lack of engineering rigor was evident by a number of work products that we reviewed; instances of procedural non-compliance. I mentioned symptom-based repairs to the containment air radiation monitors.

I will just point out this system is designed to detect RCS leaks. So they were performing symptom-based repairs to the very system that was designed to detect leaks.

Not internalizing lessons learned from past boric acid corrosion events; not fully assessing operating experience; inadequate and untimely corrective actions, and then implementation weaknesses with their employees' concerns program -- that relate or bear on the underlying technical issues.

CHAIRMAN APOSTOLAKIS: So when you say, "management," how far down do you go?

MR. HOWELL: We talked to folks from the supervisory level all the way up to the Site VP level. So what we found was that there were those who clearly were aware of the boric acid deposits on the head. Some of the folks had not availed themselves of reviewing the videotapes which graphically depict the extent and condition. Some of those were aware of it, but, again, were under the belief that these deposits would be benign.

There was a lot of turnover with the Systems Engineers over the course of three outages involved in the cleaning of the head. So there was perhaps some communication handoffs that didn't occur that should have.

But the knowledge of the head conditions, at least in a general sense, were known all the way up to the VP level. But the activity to clean the head was primarily at the contractor and system engineer level almost entirely, as far as we could reconstruct.

MEMBER WALLIS: There's nobody who said, "How come we think these deposits are dry when the video shows that they were flowing?"

MR. HOWELL: Again, they thought that the deposits were from the leaking CRDM flanges. Then I believe that the AIT followup performed by the Region, as well as our own review, indicated that there's some evidence that should have clearly suggested to them that the flanges were not leaking in the 2000 timeframe and were not the source --

MEMBER WALLIS: Even if it was the flanges that were leaking, as long as those deposits are liquid and at the right temperature and the right acidity concentration, they can corrode the heads severely.

MR. HOWELL: Correct, and that's one of the lessons that was not learned. I mean, the whole notion that it is acceptable to have leaking deposits on the head -- I mean the Turkey Point event, the Besnow event, the Salem event, and Calvert Cliffs events clearly indicate that even from the surface corrosion can be much more significant than anticipated. That condition, in and of itself, should not have been viewed as acceptable. That lesson was either not learned or forgotten.

MR. GROBE: There were two specific events at Davis-Besse. Art already mentioned the pressurizer spray valve which was of a different character. But there was also a leak on the head vent to the steam generator, where the penetration to the steam generator, there was a crack in that line and a leakage, and approximately an inch of steam generator metal had corroded away around that penetration. So it is clear that lessons had not been learned.

MEMBER SIEBER: What timeframe did that occur?

MR. GROBE: I believe it was in the mid-nineties.

MR. HOWELL: Which event are you referring to?

MR. GROBE: It was a crack on the head vent to the steam generator line.

MR. HOWELL: That was the 1992-93 timeframe. Again, that was a case where the leak was identified in 1993, but not repaired -- 1992, I'm sorry, but not repaired until the following outage in 1993 because of the notion or belief that the corrosion rates would not be extensive.

All right, next slide. The next slide deals primarily with NRC performance. In terms of reactor coolant leakage --

MEMBER WALLIS: I'm sorry, when these folks gave you their rationale for ignoring all these symptoms, is there evidence that their rationale for ignoring the symptoms was at the time that they were aware of them? In other words, is there a written record? Or is this something they made up to rationalize their behavior when they came before you?

MR. HOWELL: Yes and no, and the reason I say that is that, clearly, there's documentation to suggest that they believe that the leakage, that boric acid deposits being found on the head were from leaking CRDM flanges.

There's also one document in the 2000 timeframe that indicates -- and it's vague or arguably vague -- that the leakage may be from some other source; namely -- there's not too many other sources -- namely, a nozzle. That's the inference. Yet, there's no documentation that explicitly dispositions that passage in the condition report.

MR. GROBE: There was extensive dialog between the resident staff and regional supervisors and the licensee. I believe, was it five successive Resident Inspection Reports? That's a 30-week period of time where it is documented that we were having dialogs with them and addressing this issue.

MR. HOWELL: And that's really the next point. Reactor coolant system leakage assessment, this is what the NRC reviewed.

What we found, as Jack indicated, that there was a -- the symptoms of the RCS unidentified leakage were well-known at the plant. Consequently, they were well-known by the inspection staff, and there was inspection followup of the symptoms. What

I am talking about specifically are the rad monitoring fouling and containment air cooler fouling, in particular. This was in the 1999 timeframe.

What we found was that the followup, as Jack indicated, was of a more routine nature. What we didn't see was any focused effort on the part of the NRC to try to bore in on the source of the unidentified leakage.

Now I view that as a missed opportunity. It is not clear at all that, had that been done, that it would have helped us get to the problem sooner or get to the problem in terms of the NRC identification, but it was an opportunity to have done so.

In addition to that, what we found is that there were some actions indicated by the licensee to try to get to the source of this unidentified leakage in the 2000 refueling outage, and that was documented in the Inspection Report.

We could find no solid, hard information from the licensee that that rigorous leak hunt ever occurred during that outage, nor was there any NRC followup of that activity to determine that at the time.

There was also knowledge on the part of the NRC staff that there were boric acid deposits on the head in the 2000 refueling outage. Some of the condition reports that documented the condition were reviewed, but there was no followup of that information, nor was that information communicated to the inspector's supervisor as far as we could tell.

When we talked to the former inspector about the rationale for that, what we learned was that this particular inspector was involved with the special inspection of the pressurizer spray valve that occurred in the 1999 timeframe, a year before. So he was very familiar with the deficiencies that were identified in the Boric Acid Corrosion Program, and he was also very familiar with the corrective actions that were to be implemented to address those deficiencies.

So it was on that basis that he believed that, because of the corrective actions that should have been put in place, that the licensee would have fully assessed and evaluated any potential for corrosion on the head, would have cleaned all the boric acid off, because that was one of the findings, and made an assessment. So it was on that basis that there was no detailed inspection followup of boric acid being found on the head during the spring refueling outage.

There were some other less-direct opportunities for the NRC to have identified this issue through both licensing and inspection activities. For example, the licensee processed a tech. spec. amendment to relax the requirements, tech. spec. requirements, the allowed outage times for the containment air radiation monitors because they were fouling so frequently in the 1999 timeframe due to the boric acid deposit buildup and iron oxide.

There was some knowledge of that symptom by the licensing staff, or at least one member, but there was no description of that issue found in the licensee's submittal about the operational problems that the system was experiencing during that timeframe.

So, anyway, that amendment request was processed. So the licensee got some relief, which is one of the symptom-based repairs that I made mention of earlier.

There were also some other inspections in which we had opportunities to perhaps visually see the deposits on the head during the 1998 and 2000 refueling outages through the conduct of routine inspections.

In terms of Inspection Program

implementation, we also found some gaps where there were either requirements or implementation issues -- either the guidance could have been clarified or we didn't implement the guidance. I mentioned the RC2 event. There was no closeout of the escalated violation by the NRC. In other words, there was no followup of the corrective actions pertaining to the boric acid corrosion problems associated with the RC2 event.

There was some followup of a material control problem in which the wrong bolts got installed, and there were some other activities in which we had opportunities to sample some of the condition reports through routine corrective action inspections, where the summaries of the Condition Reports documenting the problems with the boric acid on the head were provided to us, but they weren't very detailed.

So, in reviewing those three CRs in a list of thousands, they weren't picked for samples. So there's things of that nature.

In terms of integration and assessment of performance data, as Jack indicated, we knew quite a bit about the fouling of the rad monitors. What we didn't piece together was that symptomatic repairs were occurring to the system over a period of a couple of three years.

With respect to the failing of the rad monitors, there was some installation of HEPA filters. There was a changing of the rad monitor sample points, so they wouldn't foul as fast. There was a relaxation of the tech. spec. requirement, so they wouldn't be continually in the tech. spec. LCO. They were in this LCO, just to give you some idea, hundreds of times in the period of, I think, 1999, hundreds of times, 300 times, I think.

And there was a bypassing of the iodine filter through a temp. modification because that particular filter was saturating more quickly than the other filters in that system for the other two detectors.

But none of that was brought together to paint a picture of a pattern of behavior that was clearly based on addressing symptoms.

In terms of guidance and requirements, we found examples where our inspection guidance didn't serve us as well as it could have. These primarily involve boric acid corrosion procedures, vessel head penetration guidance, inspection guidance, and also guidance in the cross-cutting areas of corrective actions, employee concerns and safety-conscious work environment.

There were some staffing and resource challenges within the Region during the period in which the symptoms were becoming prevalent. There was a period of high turnover in the Region at the time. I think three, maybe four, 0350 Panels that were going on at other plants within the Region, including the organizational unit, the regional organization unit that had responsibility for Davis-Besse.

So there was a number of challenges in terms of maintaining the staffing plan at the site. That's not a direct contributor. We can't really say that this contributed to our failure to find this sooner, but it certainly didn't help the situation.

As Jack indicated, we also found some instances in which there was some inaccurate information, Davis-Besse plant information, some of it, as Jack indicated, internal documents as well as information provided to the staff through either bulletin submissions or presentations made to various members of the staff that either contributed to, or had the potential to cause, missed opportunities for us to have identified the problem later in the 2001 timeframe.

Then we found a number of licensing process issues. There was a period of high Licensing Project Manager turnover at the plant. There were infrequent site visits by the Project Managers. Only one Project Manager was aware of some of the symptoms, even though there was these daily calls that occurred with the site.

I mentioned the tech. spec. issue. I mentioned that there was some operating experience in-service inspection reports that could have been reviewed that weren't reviewed. Also, the basis for the decision to accept continued operation of Davis-Besse beyond December 31st up to February 16th wasn't well-documented. So there were a number of ancillary issues.

In terms of recommendations, these are just categories of recommendations. There are 10 broad areas: inspection guidance -- I won't go through all of this, but we made recommendations to address guidance in a number of areas, both the underlying technical areas as well as in the cross-cutting areas, as well as other areas.

Operating experience --

MEMBER LEITCH: There's an appendix in the report that lists all the recommendations.

MR. HOWELL: Yes.

MEMBER LEITCH: I think there must be about 50 of them.

MR. HOWELL: Fifty-one, yes.

MEMBER LEITCH: Okay, and I'm wondering, is there some -- well, first of all, have these recommendations been accepted, and if so, is there a schedule and a prioritization for implementation?

MR. HOWELL: The agency approach for addressing the recommendations is kind of a two-phase report. We did our review and made the recommendations, and then a senior group of NRC managers was put together. Carl Paperiello was the head of that group.

They have recently gone through all the recommendations and have provided a report to the EDO -- I believe it was issued on November 26th -- that provides an assessment of the recommendations. If my memory serves me correctly, I believe all but two of the recommendations were accepted.

They were categorized into four broad areas, and those areas pertain to the assessment of stress corrosion cracking. That's one of the four areas. The next area is the assessment and the integration of operating experience. The third is inspection assessment and project management guidance, and the fourth is the assessment of barrier integrity requirements.

So they blend all 51 recommendations into those four areas. They accepted all but two. They clarified a number of them. They consolidated a number of them. A number of them they internally flagged as high-priority items and others as medium- and low-priority items.

In a number of cases, at least I think for the high-priority items, in most, if not all, cases the idea is that a detailed action plan would be put together to provide resources and schedules to implement those actions. That has not yet been done, since the report was just issued.

MEMBER ROSEN: Is that November 26th report on the website?

MR. HOWELL: I don't know if it has been -- Mag says it hasn't been released yet, but I think the intent is clearly to make it publicly available.

MEMBER ROSEN: It's not now public?

MR. HOWELL: I don't know. I don't know the status. I just got my copy.

MS. WESTON: Yes, it is not on the website as of yesterday.

MR. GROBE: It's not currently public. There is a scheduled Commission meeting, though, January 21st to discuss the results of that.

CHAIRMAN APOSTOLAKIS: Coming back to the recommendations, I think we all agree, and during Jack's presentation we also saw it, that we really don't understand what an adequate safety culture is and how to measure. What are the good indications? We don't know. I don't think anyone knows.

Some of my colleagues with long experience at nuclear plants tell me they walk into a facility and 10 minutes later they know whether they have a good culture there, but they can't tell me why. Now given that these people are very few, we cannot afford to have them go to all the plants and turn in a report of that. So that is one element.

The second point here is that for the last 20-25 years this agency has started research projects on organizational/managerial issues that were very abruptly and rudely stopped right in the middle because, if you do that, the argument goes, regulation follows. So we don't understand these issues because we never really studied them.

Then the react oversight process tells us that a safety-conscious work environment is very important, but we are not going to have any indicators for it because, again, we don't know what they are, but, fundamentally, if there is a problem, we will see it in the performance of the equipment.

I was wondering why, after this incident and all the stuff that has happened in association with it, you are not recommending that the agency undertake some sort of a program to try to understand these things better. Or is research something that you don't think is needed in this area?

MR. HOWELL: Well, we didn't make a specific recommendation about research, but we did make a number of specific recommendations that certainly touch on the characteristics and attitudes of safety culture. Maybe it is a packaging issue, but I think there is clearly some recognition by all who have looked at the Davis-Besse event that there are safety culture issues that need to be looked at.

So, to that extent, we did make recommendations involving an Employee Concerns Program and safety-conscious work environment and understanding the influences of schedule and other factors on decisions about work scope and things of that nature.

CHAIRMAN APOSTOLAKIS: So the

Commissioners, after they look at your report, they will say, "Aha, so we really have to do something about it. Mr. Thadani, do something about it."? Is that clear from your recommendations?

MR. HOWELL: Again, the Senior Management Review Team has reviewed all the recommendations and has, in turn, endorsed them, and so noted in their report to the EDO. You know, I don't know how clear it is.

I guess, clearly, if you read Section 3.2 of our report, I can't answer the question what an adequate safety culture is, either, any better than anybody else in this room, but, clearly, there's issues there. I think those issues are causing all of us to go back and revisit some of our past --

CHAIRMAN APOSTOLAKIS: There is a reluctance on the part of decisionmakers in this agency to get into these things. These things get us into trouble all the time. Let me give you an example.

I think Mr. Grobe mentioned that the organization did not appear to learn from its own experience and other people's experience. I think you also touched upon it.

Well, I found out the last year or so in another context there's vast literature out there by people who are not engineers who studied how organizations learn. I will be the very first one to admit that, if we think that we are going to find the solutions to our problems by looking at that literature, that's a very naive approach because we've got similar problems with psychology and management science, and so on.

But it is interesting, though, that there is this whole literature there, and we don't seem to be taking advantage of it by having our own engineers and researchers look at it and say, "A, B, F, and G are really applicable to us. Let's see how we can make it real in our environment."

There is an extreme reluctance to do that. I don't understand why not. I was hoping that some of these reports with all these recommendations were going to say, hey, go out and study these things a little more, and it is just not happening.

VICE CHAIRMAN BONACA: If I could make a comment also about the safety culture, Mr. Grobe, you showed before that you are evaluating whether or not the plant is ready to restart. One thing that concerns me goes back to the question I asked before regarding, was there any differing opinion regarding these events that were taking place, the clogging, et cetera, et cetera?

If I had known that there was different opinions at the technical level, strong differing opinions, I would feel better about the culture of the organization. You know, differing opinions may be overridden by management, and then you may find that there is a management problem. So to change management is a solution there in that case which is pretty obvious.

But when you have an organization that seems to be walking in lockstep, where everybody gets convinced very easily, and there is this refuting on a daily basis of indications, which are the most important thing that the operators have -- all you have is indications, and you have to believe those indications, not to cancel the indication. You can't just continuously cancel the indication.

That gives me some real concern. Are you looking at that as part of the restart evaluation and the safety culture? I mean, are you looking back at what was available, what transpired from meetings? That is central to the issue of the culture of the organization and how recoverable it is.

MR. GROBE: I am trying to review in my

memory the information that existed in the organization. I think there is only one example of a differing view, and that was the fact that the Condition Report was initiated in the early nineties to install these modifications in the service structure. That modification was cancelled in the early-mid-nineties; I think it was 1993 or 1994. It was initiated again during the next outage. So that would be an indication in my mind of a differing view on the part of the system engineers responsible for the head inspection.

My appreciation of what was going on in the organization is that the knowledge of head, of the materials on the head throughout the mid- and late nineties was very limited to a few people. The Operations organization was clearly not aware of the corrosion that was observed in the 2000 outage, running out of the mouse holes and pooling around the head studs.

Clearly, the system engineer and some rad protection people were well aware of it, but there did not seem to be a broad awareness of that level of corrosion products on the head. So I am not sure it is a matter so much of a lack of differing views or suppressed differing views as it is a lack of knowledge.

VICE CHAIRMAN BONACA: I was referring mostly about the filter cloggings. Those were daily events almost taking place. I mean, didn't somebody scratch their head and say, "What's going on? Why are we overriding these indications?"

MR. HOWELL: Well, they knew they had a leak. They just didn't know the source, and some had convinced themselves that there was two or three different leak sources over a period of about two or three years, including the flanges and also the pressurizer spray valve tailpipe that had been disconnected from the quench tank.

MR. GROBE: There was a substantial action plan developed to get to the bottom of the leakage. There was not a belief that it was coming from the head. There is a violation in the AIT follow-up report for failure to implement corrective actions.

The final stage of that was a comprehensive at-temperature and pressure inspection of the reactor coolant system pressure boundary at the beginning of the next refuel outage. That was not accomplished. That corrective action was cancelled.

But I believe that at the time that they were dealing, as Art indicated, with the symptoms, and not identifying the root issue, there was a significant cultural problem at the station that was focused on production and cost savings over getting to the bottom of these types of issues. It was because they didn't believe there was a safety issue, a significant safety issue.

MEMBER FORD: Art, would you like to finish up?

MR. HOWELL: That is really all I had.

MEMBER FORD: Any concluding remarks? No?

MEMBER WALLIS: Just, Mr. Chairman, before we go to the break, I would like to assure the next presenters that they will be given the time allotted.

CHAIRMAN APOSTOLAKIS: Yes.

MEMBER FORD: Art, Jack, thank you very much, indeed.

MR. GROBE: Thank you.

CHAIRMAN APOSTOLAKIS: Thank you, gentlemen.

We will recess until -- what?

DR. LARKINS: I was just going to say, George, before you recess, we want to let everybody know that, due to conditions beyond my control, the Christmas party will be deferred until tomorrow.

CHAIRMAN APOSTOLAKIS: You have no control over the weather? For heaven's sake, Executive Director.

(Laughter.)

Okay, so we will recess until five minutes after 11:00.

(Whereupon, the foregoing matter went off the record at 10:46 a.m. and went back on the record at 11:07 a.m.)

CHAIRMAN APOSTOLAKIS: The next item is Framatome S-RELAP5 Realistic Large-Break LOCA Code. Professor Wallis, it's yours.

MEMBER WALLIS: I think the Committee knows perfectly well what this is all about and you've gotten some previous information. I don't think you need any further introduction. We are a bit behind schedule. Let's go right to it.

MR. O'DELL: Good morning. I'm Larry O'Dell with Framatome. I am the Project Leader at Framatome for the development of the realistic large-break LOCA methodology.

I wanted to quickly go through today, and I will try, since this is behind, to move along fairly quickly through some of these first slides, but my objective is to give you an overview of the complete methodology, demonstrating how we conform to the CSAU approach in the development of that methodology, and then to show some selected examples with respect to what analysis we did and how those analyses actually compare to the data we were comparing it to.

But I have laid out my presentation along the same lines as the CSAU, which is consistent with the way it was reviewed in the SE. I will go through the requirements and capabilities, CSAU Element 1, Steps 1 through 6, and I will go through these fairly rapidly and my couple of a slides; go ahead and go through the assessment and ranging of parameters, CSAU Element 2, Steps 7 through 10; go through some sensitivity and uncertainty analysis, CSAU Element 3, and that's Steps 11 through 14.

On these I will move through these two fairly quickly, if it will stay on the machine there.

The first one, CSAU Element 1, there's six steps, as I indicated.

Step 1 is to specify the scenario. We have obviously specified the large-break LOCA scenario.

Step 2, select the plant types. We've selected the Westinghouse 3 four-loop and CE 2x2 plants.

CSAU Step 3 is to develop the phenomena

identification and ranking, the PIRT. We've developed that. The process we used was to start with basically the compendium, the peer reviews on that, come up with our own revisions to the compendium, PIRT, and finalize that PIRT, and it is presented in our documentation.

The next step, CSAU Step 4, is to identify selected versions of the Code. We identified and used the RODEX3 Code, which is our own internal fuel rod code, to describe our fuel, and the S-RELAP5 Code. I should also mention that within the S-RELAP5 Code we have incorporated the ICECON Code, so we have a direct relation between the systems calculation and the containment back pressure.

MEMBER WALLIS: Now you say it is a frozen code? That means that -- how far is it frozen? I think that you actually did do comparisons with data which led you to find some biases in the code, which you then corrected for?

MR. O'DELL: Right.

MEMBER WALLIS: So it is not frozen in the sense that you aren't allowed to correct for bias, but it is frozen in terms of the rest of the structure?

MR. O'DELL: Correct.

MEMBER WALLIS: So you might change a few coefficients in it or something to correct for bias?

MR. O'DELL: Right. When we went through and did a lot of the sensitivity and calculations, we had to implement a number of biases in the code in order to perform those sensitivity analyses, and we ended up with a version of code which had those multipliers in the code.

Okay, the next step, CSAU Step 5, has to do with the development of the documentation. We develop models, correlations, programmers, and input manuals for all of the codes used.

The next step was determine code applicability. We went through the applicability step, demonstrated that the code was applicable to the selected scenario, large-break LOCA, and the various plant types that we had selected.

Now moving to CSAU Element 2, the first step of that is CSAU Step 7, which is to identify assessment matrix for the analysis. We identified 15 separate effect test facilities that we used, and we evaluated 130 tests within that set of facilities. We also identified two integral test facilities, and we evaluated six tests within that facility.

The next step is the CSAU Step 8, which has to do with nodalization. We selected the nodalization, initial nodalization, based on our own experience in applying the code. Then we performed a series of plant studies, modified that nodalization, then had a peer review where we sat down and presented the nodalization we had come up with. As a result of that, we went off and did additional plant model studies where we finally came up with a final plant model that we used in the assessment evaluations.

MEMBER WALLIS: You did sensitivity studies of the nodalization?

MR. O'DELL: Yes. We looked at a series of nodalization studies in the core, the downcomer, upper head, and upper plenum area, and lower plenum area. So we did a fairly extensive set of nodalization studies.

MEMBER WALLIS: And these sensitivity -- what do these show?

MR. O'DELL: Well, with relationship to the downcomer, it showed that there was a tradeoff there between basically code run time and matching the data. Going with a simpler nodalization improved the code run, obviously, and gave slightly conservative or somewhat conservative answers. We went with that nodalization.

The same thing was true in the lower

plenum. The core we found, looking at 10, 20, and 40 nodes, axial nodes, within the core region, that 20 was basically adequate. We selected a 20.

MEMBER WALLIS: You mentioned a tradeoff with run time. Were you restricted on the kinds of computers you could use by law?

MR. O'DELL: Well, we're restricted on a number -- on the qualification of the code on a computer, okay? Obviously, if we moved the code to another computer system, then we have to go through a complete new qualification of that, too.

MEMBER WALLIS: But this means you were restricted from using what might be much more rapid --

MR. O'DELL: Yes.

MEMBER WALLIS: -- and capable computers because of something in the regulations?

MR. O'DELL: Right. Again, the computers are evolving so rapidly that, you know, we started this in 1997 and basically froze the code versions. To move it to another version, rerun all the analysis and everything, would have been a fairly major undertaking.

MEMBER WALLIS: So these computers weren't as out-of-date as they might have been if you had frozen it earlier?

MR. O'DELL: Exactly.

(Laughter.)

MEMBER SHACK: But that means you are stuck with 1997-vintage computers then? Is that the statement?

MR. O'DELL: Unless we move the codes and then qualify them by Appendix B to the new set of computer systems, yes.

MEMBER WALLIS: Was this 1997-vintage computers or was this the qualification? So it is actually an older vintage than 1997?

MR. O'DELL: No, it is actually somewhat newer than 1997. We started in 1997. We did a lot of preliminary work then and actually froze the codes in about the 1999 timeframe.

MEMBER WALLIS: I think in the Subcommittee meeting, when there was some mention of some codes being restricted to run on VAXes, that seemed somewhat preposterous. That didn't apply to you though?

MR. O'DELL: No, that doesn't apply to us. We're running on HP workstations; Hewlett-Packard workstations we're running on. We would like to be able to run on a Linux-Dell cluster.

Okay, again, with the final nodalization, we ended up with 2D components for the downcomer core and upper plenum, which we found was necessary to catch phenomenon.

The next step was code and experimental accuracy calculations that we did. In this, what we did is we went through and determined the code model biases and uncertainties by comparing them to various separate effect tests and experiments.

We started off looking at 23 phenomena from the PIRT. This was everything ranked five or higher in the PIRT. Based on sensitivity studies that we did on that, we ended up with 13 phenomena that we were treating statistically, and 10 of the phenomena that we found were either unimportant, actually unimportant in the LOCA calculation, or modeled conservatively.

We then went through a step to confirm those biases and uncertainties by going through on independent sets of data on the separate effects test and integral tests where we applied the biases and uncertainties and looked at the effects of those on this independent dataset. The purpose here was basically to validate the biases and uncertainties that we detect.

The figure, I picked one of the LOFT

tests. This was the highest-powered LOFT LOCA test, which is LOFT out the LP-LB-1. What is shown here is the data, showing the range on the data with the uncertainties in the data.

The solid line is the calculation we did where we had removed none of the biases from the computer code models. We then went in and applied the biases we had determined from the other separate effects test, not the uncertainties, just the biases.

What it did is it moved the calculation down to better agreement with the data pretty much across the whole axial range. Now this demonstrated to us that the biases at least were behaving in an expected fashion.

MEMBER POWERS: Is this the peak clad temperature that you are applying here?

MR. O'DELL: Right, this is the peak cladding temperature at any axial location at any time during the --

MEMBER POWERS: So it is not a temperature of a particular place in the core?

MR. O'DELL: Right.

MEMBER POWERS: It is just whatever is the highest at that particular place?

MR. O'DELL: That point, yes.

MEMBER POWERS: Do you have a similar plot of the temperatures at a particular place?

MR. O'DELL: Right, that is the next slide. We went through, and what we did here is, again looking at the biases and uncertainties, here what we did is we went through and we applied the biases and the uncertainties where we could identify them for the LOFT experiment.

What you see is the data at the PCT node. This is the PCT node, again showing the variations around the data.

The top calculation, of the 59 calculations we did for the statistical analysis, that was the run that had the highest PCT in it. The other one is the one that had the lowest PCT in it.

So that is how we picked through the comparisons. If you plot all 59 of them on here, you can't see anything.

There were ranges of the calculations which agreed very well with that temperature plot, but these obviously haven't quenched yet. That is because in our model we do have a conservative T-min model which restricts the quench time. So we tend to quench later than the --

MEMBER WALLIS: Why are you conservative

if this is supposed to be a realistic code? It would seem to me you ought to be realistic about the quenching, too.

MR. O'DELL: I would agree with that. We went through a set of analysis based on a series of data, and we came up with a conservative treatment for a T-min value. That was based on basically stainless steel, electrode heater-type rods. That is known to be conservative relative to the other data. At the time we didn't really have other data that we thought we could use to do that.

You want to be realistic, but being realistic means that I have to begin with uncertainty, which means I have to have a sufficient amount of data to do that. If I don't have sufficient amount of data to do it, then I end up taking a somewhat more bounding approach to it.

MEMBER WALLIS: Well, I guess you claim, then, you don't really care what happens because the PCT is long over, and PCT is the criterion. So it doesn't matter too much to get it right after, say, 70 seconds or do you have to get it right between 10 and 50 seconds?

MEMBER POWERS: But isn't there an eight-second criteria concerning hydrogen production? And if I predict the cooling is slow, then I don't have any possibility of predicting thermal shock to the oxide that is on the cladding? And if I don't thermally shock the oxide on the cladding in my calculations but do in reality, won't I underestimate the hydrogen production?

MR. O'DELL: I would think you overestimate the hydrogen production because I am spending more time at higher temperatures. So I am generating more --

MEMBER POWERS: If I shock my clad oxide and spall it off?

MR. O'DELL: Well, eventually, though, I will quench out here, will quench when the temperatures get down into the 10 criteria. When it does quench, then I get the same thermal-shocking-type effect, but I have spent more time at temperature. So I will have more oxide.

MEMBER POWERS: Since the oxide grows as a square root of T, I would think that shock spall and reoxidize would give you a lot more oxide.

MEMBER KRESS: But wouldn't that require a different oxidation model than they have in the code?

MEMBER POWERS: It would require one that is realistic, yes.

MEMBER KRESS: Well, I think, what do you have, Cathcart-Pawel?

MR. O'DELL: Cathcart-Pawel is what we are using.

MEMBER KRESS: And it probably doesn't include --

MEMBER POWERS: Assuredly, it does not.

MEMBER WALLIS: It doesn't include oxide spalling, does it?

MR. O'DELL: No.

MEMBER WALLIS: So I think Dr. Powers has pointed out there is some physical phenomena here which really do affect what happens which are not modeled in the code.

MEMBER KRESS: And the only way you uncover that is by experiment, I think.

MEMBER WALLIS: Which do affect one of the criteria rather than just what happens, and the degree of hydrogen production, the degree of oxidation is one of the evaluation criteria. If it is affected by the spalling of this layer, then here's a physical phenomenon which is not presently modeled in the code, which affects one of the evaluation criteria.

MEMBER KRESS: That looks like a fairly

benign thermal shock to me in the test data. I'm not so sure that would spall an oxide layer on a clad.

MEMBER WALLIS: Maybe we will ask the staff what they conclude from this.

MEMBER KRESS: I don't know what the thermal shock is. All I have done is temperature versus time. I don't know what that means in delta T across the clad oxide layer, but --

MEMBER POWERS: I don't either, but I guess from previous presentations I am not willing to simply say, well, that is reasonable.

MEMBER KRESS: No, it is certainly part of a potential possibility, I think, yes.

MR. O'DELL: This was something that wasn't identified in the PIRT process, I mean the process that we went through.

MEMBER WALLIS: You should put Dr. Powers on your PIRT team.

MEMBER KRESS: Where you would see that would be in comparison in the hydrogen generated with what you calculate, I think would be one way to look at it.

MEMBER SHACK: Is that a thermal hydraulic problem or is that a cladding problem?

MEMBER KRESS: Well, it is included in

thermal hydraulics because we have put in -- thermal hydraulic codes include the heat-generating sources. Part of that is the oxidation.

MEMBER RANSOM: Has that phenomenon ever been observed in any of the experiments with fuel where you get spalling of the oxide when you place the fuel and increase hydrogen production?

MEMBER POWERS: The problem is that I don't know that we have done any experiments with fuels that have experienced the levels of burnup that we are now taking fuels to.

MEMBER KRESS: It has certainly been observed with some of the air experiments, some of the air oxidation experiments.

MEMBER POWERS: Oh, yes, but then you are talking about some serious oxidation there. It is really a question of what happens if you get up close to this 17 percent limit. If you are going to have a thin oxide that is basically epitaxial, it doesn't shock. But if you get up close to your 17 percent limit, then I think you would have at least some potential of shocking the oxide.

MEMBER KRESS: That is a pretty thick layer, isn't it?

MEMBER POWERS: Yes, that is approaching

100-micron layer, but then we have seen fuels taken to, re-Zircaloy clads taken to 50- and 60-gigawatt days per ton that will start off with oxides that are pretty thick.

I mean the one thing you know is that unstabilized Zirconia is one of the shockier ceramics. Now there is a figure of merit that you can use for looking at thermal shock. Kendurgy has published it. He developed that based on Zirconia. So it is probably a pretty decent one to use, though it is not exactly for this geometry. But it might be fun to go through and see what kind of delta T Tom was talking about would require to shock it and see if you were getting anything close to that.

MEMBER WALLIS: Well, Dana, I think later on Framatome is going to argue that the degree of oxidation is actually very low, so they don't have much of a layer, nowhere near 17 percent.

MEMBER POWERS: Well, it depends on how -- I mean, if you burn the fuel up, you start off with an oxide.

MEMBER WALLIS: I don't know that that's actually considered in these codes at all really, initial oxide layer.

MR. O'DELL: It was not considered in our calculation of the transient-induced oxidation. I think we do look at the time in cycle statistically as you are going through it. So we do look at various fuel, but in general the highly-burnt fuel is operating more out on the periphery of these cores, and, consequently, are at very low powers. So they are not --

MEMBER POWERS: I guess I am a little bit of a victim of the preceding presentation that told me not to accept plausibility arguments. I would really rather see someone address the issue if we are going to do something that's called realistic.

MEMBER RANSOM: Larry, one other question. Is the reason that you did not quenchen those runs the fact that you have used a conservatively low T-min?

MR. O'DELL: Yes, that is why we haven't. It hasn't got down to the quench temperature yet. We selected it, you know, the timeframe over which we were running the 59 cases, to basically bound when the experimental data got to quench. As I indicated, there's a number of these runs, the 59 we made, that reached quench and quenched reasonably close to the actual data's time.

But we are bearing a lot of things here with the heat transfer effects and this type of thing.

MEMBER KRESS: Dana, if you ran this calculation with the Baker-Just model, would that bound the issue you are dealing with? I thought the Baker-Just was looking at fresh Zircaloy, so it didn't have much of an oxide layer on it.

MEMBER POWERS: Yes.

MEMBER KRESS: That might be one way to bound it, bound it by calculation.

MEMBER POWERS: Yes, but, I mean, that's kind of --

MEMBER WALLIS: Well, maybe we can identify someone in the staff or the research part of the NRC who knows the answers to your question.

MEMBER POWERS: There has been some French work -- I will have to admit I can't even understand the paper, let alone say what it does -- looking at the issue of when you can fracture of these oxides off the cladding, but I'm just not familiar with it.

But, as you go from using Baker-Just-type kinetics, the more realistic kinetics and thermal hydraulics, I mean it seems to me you have to recognize the phenomena that you were deliberately skirting when we decided to go with Baker-Just kinetics.

MEMBER WALLIS: I think, as Tom pointed

out, it is a clean fuel. So if you spall off the oxide layer, doesn't it just become clean again, and it goes back to what you would get if you assumed it was coming from the start?

MEMBER POWERS: Well, if you are using Baker-Just kinetics, it is not quite as -- I mean, quite frankly, those are the complexities that people would be saying, okay, well, we'll just use this demonstrably conservative kinetics and maybe that will cover it up.

Don't you have to look at those kinds of -- I mean I don't know. I just don't know.

MR. O'DELL: Yes, I think when I get a little further along in the presentation, as Dr. Wallis indicated, I will show you basically what we were predicting for at least the three-loop sample problem in the way of oxidation. We are significantly away from the 17 percent limit.

I don't really believe that -- I think you will hit the 2200-degree F limit a long time before you hit the oxidation limits in these calculations, based on the Appendix K analysis that we have done for years --

MEMBER WALLIS: So could we move on and maybe we will get back to that one?

MR. O'DELL: Sure.

MEMBER SHACK: Can I just ask a quick question?

MEMBER WALLIS: Okay.

MEMBER SHACK: On the previous slide, you said something, 23 phenomena valuated, 13 treated statistically, 10 found. What do you mean statistically? You actually found biases and uncertainties in a statistical sense for those?

MR. O'DELL: Yes.

MEMBER SHACK: Then 10 phenomena were either unimportant, you didn't care whether you modeled those well --

MR. O'DELL: Right. Basically, what we showed there -- and I will get to a slide on that, too -- where we went through these sensitivity analyses and then we looked at a very simple square root of the sum of the squares type of an effect to see what kind of estimate of what the effect would be, you find that by the time you get down to about 50 degrees, it is only a couple of degrees in PCT as far as the impact goes.

MEMBER POWERS: Let's see, you make assumptions that these statistical variations are additive independent? Do you have to assume Gaussian?

MR. O'DELL: With respect to distributions, we use a series of distributions. We use uniform distributions. In some cases if we can demonstrate that is normal, we do that. If it is with respect to the plant parameters, we usually try to go get plant data as to actually how they operate and then weight those distributions based on how the actual plant operates.

MEMBER RANSOM: One more quick question, Larry. On your T-min correlation on that previous slide, where you showed the LOFT LP-LB-1 data and you showed your adjusted or with the biases in it, is that including the T-min that you would use, then, for the next series of calculations?

MR. O'DELL: Yes.

MEMBER RANSOM: So the T-min you are using is your best estimate from the separate effects test then?

MR. O'DELL: Yes, recognizing that --

MEMBER RANSOM: Or realistic?

MR. O'DELL: Yes, recognizing that it is conservative because of its stainless steel electrode heater.

The next CSAU, Step 10, deals with scalability. There's a couple of issues there. One is the scalability of the tests, and the other is the scalability of the code models.

We went through and basically demonstrated that the tests were scalable and that the code was scalable. For the cases where it wasn't scalable, we used -- it was really the downcomer-type areas, we used the full-scale UPTF test to validate the code on those.

MEMBER WALLIS: Now the nodalization is also tested in the scalability?

MR. O'DELL: Yes. We have consistently developed the model for the plant and then applied it to the assessments.

MEMBER WALLIS: Because when you scale up, this is a balance of phenomena that changes a bit. The min-noding doesn't always catch the same balance of phenomena if you fix the noding geometrically, but as long as you do some sensitivity tests, you probably will pick that up.

MR. O'DELL: Right, and I think that was part of the thing we were looking for when we did the analysis for Semiscale LOFT and CCTF. We looked at a range of scales there, and we demonstrated that the biases and uncertainties that we generated matched this additional data. That data was not the same as used to drive the biases and uncertainties.

MEMBER RANSOM: Larry, in the nodalization studies you did, did they show substantial convergence, and that as you reduced -- or increased the fineness of the nodalization, show a tendency to converge to a fixed answer?

MR. O'DELL: I would say, in general, yes. I mean, when we went to the nodalization of the core, we went 10, 20, and 40.

MEMBER RANSOM: Right.

MR. O'DELL: We also looked at it on some of the FLECHT SEASET tests with that same type of nodalization approach. Basically, we didn't see much difference in the result for any of those three nodes as such.

So what we decided to do was go with the 20, which allowed us to match up uniquely with the spacer locations in the core and also would support the matching up with the intermediate flow mixes that some of the fuel designs had.

Moving now to the final CSAU element, that's Element 3, the next step, CSAU Step 11 is to go through and develop reactor input parameters and state list. We went through the tech. specs. and FSARs to develop that list. In the reactor we had a customer working with us through that part of the process, so that they helped us identify that parameter list.

Step 12 is to do a series of sensitivity studies. We ran over 250 different sensitivity studies where we looked at plant parameters and phenomena-ranked five or higher, as I previously indicated. The results tended to confirm the PIRT rankings and defined the important PIRT parameter or plant parameters, and the plant parameters which we found to impact the PCT we then included in this statistical analysis.

MEMBER WALLIS: I want to go back to this noding business, the question about whether or not or how noding scales and how you evaluate whether noding scales. I am trying to get it clear just what you did.

Usually, I think CSAU advises that you fix the noding, that you do some noding and you experiment with all kinds of noding until you can level the scaled tests and everything, and then you fix that noding when you go to the real --

MR. O'DELL: Correct.

MEMBER WALLIS: And this would prevent you from picking up differences which were scale-dependent. If it turned out that, because of the phenomena, the balance of the phenomena at full scale is somewhat different physically, the noding doesn't capture that, you could test this by doing, presumably, noding experiments at subscale and at full scale and comparing the results of the noding tests of the two scales.

Did you go that far?

MR. O'DELL: No. Okay, basically, what we did is we did all of our nodalization studies on the plants, plant models, initial ones anyway. Then we went through and looked at LOFT, Semiscale -- or not the Semiscale -- LOFT CCTF, FLECHT SEASET tests, and UPTF tests. We looked at those with the nodalization that we got out of the plant studies.

MEMBER WALLIS: You fixed it now?

MR. O'DELL: Yes, it was a fixed nodalization.

MEMBER WALLIS: So it is geometrically fixed? If you have 10 nodes in the downcome, you still have 10?

MR. O'DELL: Right, and that was how we performed it.

MEMBER WALLIS: So it wasn't, then, what I tried to indicate, maybe not very well, that the way to try to evaluate whether the balance of the phenomena changes as you go to different scales by changing the noding --

MR. O'DELL: No, we did not --

MEMBER WALLIS: They're still arguing that the node is bigger than the reactor even though it is the same fraction of the height; therefore, the bubbles take longer to traverse the node, and so on. So something is changing in some of these.

MR. O'DELL: Right, but what we did maintain, when we went through this -- for example, if you look at the LOFT test, it is a shorter core. We maintained the node size in that case. So if we would normally have 20 nodes in the reactor core, then we cut it down to maintain the six-inch node in the --

MEMBER WALLIS: Okay, so now you are balancing the bubble thing, but you are not balancing the geometrical similarity of the nodes anymore? It's a tradeoff?

MR. O'DELL: There's a tradeoff, yes, and we felt that, at least from our perspective, when we were doing the nodalizations, we wanted to maintain the node size.

MEMBER WALLIS: It is a bit difficult if you have a node which is two feet long in the core and you go to a really small experiment.

(Laughter.)

MR. O'DELL: Basically, our guidelines that we put together for developing that called for approximately six-inch nodes to match up with space and location and in an intermediate flow that existed.

MEMBER RANSOM: What do you mean by the term scalability? Generally, we use that to indicate similarity. There are geometric scales. There are Reynolds number or Nusselt number scales. Similarity would require that all of these non-dimensional parameters be the same. So I am kind of wondering, what you mean by similarity -- I mean scalability?

MR. O'DELL: Well, from the standpoint of scalability, what we were meaning is that it is the ability of the code to scale across the ranges of tests and the ability of the tests to scale up --

MEMBER RANSOM: Do you mean to get good agreement --

MR. O'DELL: Right.

MEMBER RANSOM: -- at different tests at primarily, I guess, different geometric scales? Is that right?

MR. O'DELL: Right.

MEMBER RANSOM: Length scales?

MR. O'DELL: And, for example, what we

found is that you really can't volume weight the downcomer. Where they have done that in experiments, they got poor results.

So what we did in that case is make sure that we had UPTF tests in there which were basically full-scale-type tests to demonstrate that the code was behaving properly in the place they needed to behave properly.

MEMBER WALLIS: So it probably means that when you go to these realistic codes, you have to do more of the sensitivity experimentation to satisfy yourself that you're capturing different ways in which the code could give uncertain answers.

MR. O'DELL: Right, and I think that is part of going through the PIRT process and then the development of the assessment matrix, is to try to cover the issues of scalability.

MEMBER WALLIS: And if you ran on the most up-to-date computers, it really wouldn't be very difficult to change the nodes.

(Laughter.)

Most CFD codes, you just have a subroutine that sets meshes and nodes, and you can just, with the touch of a button, change the nodalization and run it again.

MR. O'DELL: Yes, we recently moved our CFD code to a Linux cluster, and it went from like eight hours to run a case to 55 minutes.

(Laughter.)

So there's a significant change there.

MEMBER POWERS: You need a bigger cluster.

MR. O'DELL: Pardon?

MEMBER POWERS: You need a bigger cluster.

(Laughter.)

MR. O'DELL: This is our first step.

MEMBER POWERS: You tend not to do that. You tend to keep the run time still at 55 minutes; you just increase the density of nodes in the thing.

MR. O'DELL: The problem is bigger.

(Laughter.)

MEMBER SHACK: But you're still running the data hourly.

(Laughter.)

MR. O'DELL: This was, again, what I alluded to earlier, where we have gone through and just listed a series of the parameters. We looked at the total of 44, 23 for the PIRT and 21 various plant parameters.

What is shown here is basically the sensitivity we got out of the study and then the total tolerance, which is just the square root of the sum of the squares and then the difference or the change in that tolerance.

Again, this is just an approximation to get a feeling for what's going on. As I indicated earlier, as you get down to about 50 degrees, you are within about a 3-degree effect on the PCT.

MEMBER WALLIS: Now these are all the parameters that you could change or that you considered to change?

MR. O'DELL: Right. Well, this is a partial list. It actually goes on for about three slides.

MEMBER WALLIS: I guess thinking about our discussion last month, core interface friction is one of the terms, affects one of the terms in this momentum balance that we talked about for some hours. There are other terms in that momentum balance which are also uncertain. You don't have any multipliers on them.

So one thing which one could recommend is that this list isn't as complete as it might be, doesn't sort of encompass perhaps all the things you are uncertain about, and it might be worth introducing some other ones as they are identified.

MR. O'DELL: Yes, the list that we put together followed, again, the CSAU approach, which was to go through the PIRT process, and the PIRT process identifies the phenomena. Then we tried to go through, based on that, and come up with our sensitivity --

MEMBER WALLIS: The thing is, if no expert has ever tried to put these multipliers on a term and see their effect, they don't have much basis for deciding whether or not they matter.

MR. O'DELL: A good point.

MEMBER SHACK: When you range the values over the range, you get a change of 181 degrees? Is that what this is telling me?

MR. O'DELL: Right. That is basically -- what we did is take an up-skewed and a bottom-skewed axial shape, and the variation we got on that kind of variate calculation was 181 degrees. We went through and were doing the same sort of things. Like on Fq, we said, where did the plant expect to operate nominally with that Fq, and then what is the tech. spec. limit? We looked at what the effect of Fq was.

So there's two things in here. One of them is the sensitivity to that particular parameter, but also coupled with that is what you assume the range is relative to those particular parameters.

MEMBER POWERS: And you've done these things all one variation at a time?

MR. O'DELL: Yes.

MEMBER POWERS: Are there synergistic effects of any significant magnitude?

MR. O'DELL: We didn't get into it in this type of a study because we were planning on using the non-parametric statistical approach where we vary all the parameters at the same time. So any synergistic effects get captured in the approach.

MEMBER POWERS: Sure.

MEMBER RANSOM: But these are generated one at a time?

MR. O'DELL: Yes.

MEMBER RANSOM: You use the multipliers or some variation on the particular parameter, like single or interface drag, and then those are the effect on the P-clad temperatures, I guess, right?

MR. O'DELL: Yes. Yes, throughout we used the P-clad temperature as really the governing decision parameter.

Okay, the next step, CSAU Step 13, is to use the uncertainties developed from the assessment as input for the analysis. Here, as I just indicated, we differed here from the CSAU. They used a response surface technique that limits the number of parameters that one can use. So, instead, we have used non-parametric statistics.

It propagates the uncertainties directly using the code, allows the statistical treatment of a large number of variables, provides a 95/95 PCT and associated maximum nodal and total core oxidation. It relies on the execution of 59 cases to determine the 95/95 limit.

Each case, as I indicated, is defined by randomly varying each parameter within that case. So if you look at --

MEMBER WALLIS: Including the break size?

MR. O'DELL: Including the break size, yes.

If you look at just a schematic, basically a list of parameters, and generate the 59 cases, under Case 1 there would be A1, B1, C1; Case 2, B2. So you are ranging there and directly propagating any co-dependence and just do the calculation.

Okay, with respect to CSAU Step 14 --

MEMBER POWERS: You treat all of your parameters as being independent?

MR. O'DELL: From the standpoint of

developing the biases and uncertainties, yes.

MEMBER POWERS: I mean, I haven't gone through and looked at them in detail, but is that a reasonable thing to do?

MR. O'DELL: In looking at the analysis, we didn't try to go through and see if there was some interdependencies or separate out any interdependencies. Obviously, when you get into like the heat transfer coefficients, we couldn't separate the individual heat transfer coefficients out because we couldn't find sufficient data for it. So we did the uncertainties on the total heat transfer coefficients.

So you sort of get into that with the compensating air question. There probably is some, but the idea is to demonstrate that it is adequate over the range that we are applying it.

MEMBER WALLIS: If I look at your list of parameters, there's a very few that might be interdependent, but one might say that a core interface friction maybe is in some mechanistic model, which also affects the heat transfer coefficient. So the two are not completely independent perhaps then.

MR. O'DELL: Right.

MEMBER POWERS: Presumably, decay heat and core power are very highly correlated.

MEMBER RANSOM: Probably like Rawl's analogy says that friction and heat transfer are related. So they would be to a degree.

MR. O'DELL: Okay, and the final step of the CSAU approach is Step 14. That is to provide a total uncertainty for the analysis. We provided two sample problems, the four-loop and the three-loop sample problem.

For the four-loop sample problem, the limiting case was Case 22 out of the 59 we ran. For 95/95 PCT, it was 1686 degrees F. The maximum level of oxidation, .8 percent. The maximum core oxidation, .02 percent, and we reported the 50/50 PCT out of this as just a comparison. The 1375 to 1686 would be about a 300-degree difference.

The three-loop case, Case 41, was the limiting case, PCT 18, 153 degrees F, 1.2 percent on the maximum nodal oxidation, and the maximum core oxidation, .04 percent. We had 1500 degrees F on the 50/50 PCT.

MEMBER POWERS: And these oxidations were all incremented from what you started with to what you had at the end of the calculation, right?

MR. O'DELL: Yes.

The next slides show where we went through and basically bend the 59 calculations for the three-loop sample problem, and a four-loop sample problem gives you similar-type results. What this shows is basically what the calculations gave us in the way of PCTs, the limiting PCT being the one at 1853 out there, shown in the 1850-to-1900 bin.

You can see from comparison to this that the 2200 one, as we scaled, they were reasonably close to that.

MEMBER WALLIS: And the peak at 900 is probably due to some physics which says that you can't get below a certain value, and certain things combine to make it like a slight pileup of data down there.

MR. O'DELL: Well, there's that, and there's also, you're seeing there's the effect of modeling those split and guillotine breaks in here. So some of these lower ones down here can fall out of your spectrum.

Okay, the next slide shows, again, just a comparison three-loop sample problem, the peak local oxidation. Again, it's got a limit of 17 percent, and we're significantly away from that at the 1853. We also ran a series of calculations where we just physically drove the power up until we got up to about

2200. We are in the 5 or 6 percent range compared to the 17 percent range at that point in time.

So what you conclude from that is that we probably aren't going to ever hit the oxidation limits and not have already exceeded PCT limits.

MEMBER WALLIS: So you are invoking one of those clauses in the regulations which says you don't have to do a full statistical analysis which meets 95 percent certainty on all three of these criteria.

MR. O'DELL: Exactly, yes.

MEMBER WALLIS: So that if you can show that PCT by itself is such a dominating criteria, all the others are then going to be met with I think it's high probability or some term like that.

MR. O'DELL: Right.

MEMBER WALLIS: It's so vague in the regulations.

MR. O'DELL: Right.

MEMBER WALLIS: Therefore, you're okay. You just need to focus on PCT. Everything else will be okay?

MR. O'DELL: Right, and we've gone through a statistical analysis where we took this three-loop sample problem that I am showing here, the results of the four-loop sample problem, and the results of the three-loop sample problem driven up to 2200, and we have done a statistical evaluation of that. We will be using that to justify --

MEMBER WALLIS: So for those who insist on at least providing some probability, rather than a plausibility argument, you could provide the number?

MR. O'DELL: Exactly.

MEMBER WALLIS: Now is that, let's see now, I guess it is okay as long as things are sort of well-behaved. If it turns out that local peak oxidation, nothing much happens until you get up to 2000, and then all of a sudden it takes off, then you would have some different conclusion perhaps.

MR. O'DELL: Well, and that's why we ran the three-loop case up to 20 -- actually, we ran it up; we approximated it kind of in the PCT we got out of the 59 cases on there; it was actually around 2300.

MEMBER WALLIS: That is probably a wise thing to do, is to see if there isn't some cliff that you fall off --

MR. O'DELL: Right.

MEMBER WALLIS: -- with the other variables.

MR. O'DELL: Exactly.

In conclusion, then, we have provided you a brief overview of the complete methodology. We have demonstrated how we used the CSAU methodology elements and steps. I believe we have demonstrated and proved statistically treatment through the use of the non-parametric statistics which allow us to treat a large number of parameters, and we didn't end up having to determine some delta penalties.

We used the SET experiments that we had to remove the biases actually from the code models and to determine the uncertainties. Then we evaluated those biases and uncertainties on a separate database to determine that they, in fact, scaled across the -- they were going to be fine.

MEMBER POWERS: Let me be clear on your non-parametric statistics. You did that just conventional Monte Carlo? You didn't do a Latin, limited Latin Hypercube sampling?

MR. O'DELL: No, we didn't do Hypercube sampling.

MEMBER POWERS: Just a straight Monte Carlo? Good man.

(Laughter.)

MEMBER WALLIS: Is Jim Mallay going to make a statement now?

MR. O'DELL: Yes, I think Jim has a --

MEMBER WALLIS: Any more questions for Mr. O'Dell?

(No response.)

Thank you very much, Larry.

MR. MALLAY: Thanks, Larry.

I just wanted to make a couple of statements here. First of all, I wanted to acknowledge the participation of Carolina Power and Light, now known as Progress Energy. They have participated with us through this entire process, the development of the methodology, doing some of the peer reviews, and they have been very supportive. Obviously, they have an objective here because we have a contractual commitment to use the realistic LOCA for their plants, but I think it is significant that this utility has taken considerable part.

The second thing I wanted to acknowledge is we have here with us today Darren Gale, who was brave enough to come in through the storm this morning. He's our Vice President of Fuels Engineering and Sales. Therefore, he is going to be a primary user of this methodology.

The other remark I wanted to make is about our documentation. I want to take just a minute to go through some of the background here.

During the last few discussions we have had with the ACRS Subcommittee on Thermal Hydraulic Phenomena, the Subcommittee has encouraged us to examine what I will call the nature of our documentation.

Frankly, when this subject first came up a couple of years ago, we were a bit puzzled as to why they were making this remark fairly insistently, because the feedback we had gotten consistently from the NRC staff was that our documentation was exceptionally technically clear and complete, and we appreciate those comments.

However, at the last Subcommittee meeting, which we held about three weeks ago on the 14th of November, we arrived at a common understanding. Although our documents might be clear to people who understand the RELAP set of codes and how they are applied in LOCA analysis, much of the terminology and the approaches we used to apply the simplified forms of very complex equations could be confusing and mystifying to those who are schooled in thermal hydraulics, but not this specific type of application.

Specifically, we were being asked by the Subcommittee to speak to a reader who has expertise in thermal hydraulic phenomena, but not necessarily the narrow application to the LOCA analyses. Therefore, our documents, they felt, needed to lay a better groundwork, if you will, for this specific methodology and to help the reader understand how the model relates to the physical layout of a PWR and how the fundamental equations are made to successfully simulate complex thermal hydraulic behavior, and specifically how these models can be successful through the adjustment of a few key parameters, some of which Larry mentioned here this morning, and specifically loss factors.

In any event, we at Framatome have committed to reformat our theory manual, so that an expert reader, albeit uninitiated in RELAP, can understand what we have done. We have hesitated to expand and reformat this document because it will be seen only by a very limited audience. These documents, as you can appreciate, are proprietary and, therefore, can be read by only a few people, those who need to understand the models, such as the regulator, the NRC, and perhaps some of our customers, but we are going to do that.

To give you another piece of background, the NRC will be seeing our S-RELAP5 model again. The application you have in front of you is for PWRs of the non-B&W design. We plan to expand the use of S-RELAP5 to all of our thermal hydraulic analyses. The next step is to apply the model to BWR non-LOCA safety analysis, and the second step after that is we plan to apply this model to BWR LOCA analyses.

In any event, we will revise the theory manual well in advance of our next submittal of S-RELAP5, and we plan to show it to the NRC staff to gain its concurrence that the rewrite is a clear exposition of the model. Our goal is to present the equations actually used, including loss factors that contribute so significantly to the success of the model and how two-phased flows are handled, for example.

We will explain the conversion of complex geometries to a one-dimensional straight-line approach, which is actually used in most of the RELAP codes. Other similar changes will be made to help the reader understand the implementation of the model. So I just wanted to make that public, that we intend to work with the staff in reformatting our documentation.

MEMBER WALLIS: You have put a certain slant on this discussion that we had, and that was that the theory is fine, and it is just that outside experts don't understand what you did.

MR. MALLAY: Correct.

MEMBER WALLIS: I think we have a slightly different slant on it, that we are trying to figure out if you understand what you did.

(Laughter.)

And if you understand the implications and the uncertainties and possibly not perhaps errors but causes of, well, the uncertainty we were just talking about, the way in which you formulate these equations; it is not just the way in which you tweak the coefficients, but the way in which you formulate the equations themselves leads to predictions which are not as good as they might be. That needs to be understood.

MR. MALLAY: Yes, that is certainly true. We are neglecting a lot of things in the formulation of the equation itself.

MEMBER WALLIS: Right, and I think the code does have to -- the documentation does have to stand on its own and be convincing. After all, you are the experts, so you ought to be able to give the impression that you really do understand what you are doing.

MR. MALLAY: Right.

MEMBER WALLIS: And that should come

across not just in the documentation, but also in the presentations you make to the Subcommittee, or whatever it is.

So I suggest that you go back and read the transcript of our meeting and ask yourselves what kind of impression you made in terms of convincing us that you understood what you were doing, and that next time the transcript reads somewhat differently.

MR. MALLAY: Uh-hum, I appreciate that. Yes, in fact, Larry O'Dell and I had a conversation just in the last couple of days about that situation. I guess being the pure engineers that we are, maybe we don't make as good of salesman as possibly we should be.

MEMBER WALLIS: No, that is not an excuse though. I mean, I am tired of hearing that, because we are engineers, we can get away with stuff which you wouldn't get away with otherwise. That sounds like, because we are lawyers, we don't have to do some of the things other people do or something. That is not a good reason. Engineers have to do what's the right thing for the purpose. It doesn't mean that we have to be finicky, sort of academically perfect, and all that, but it has to be good enough.

MR. MALLAY: We are very excited about

this model.

MEMBER WALLIS: In fact, in some ways that is a bigger challenge, to know it is good enough for ensuring purposes, than to just stick to some kind of scientific rigor. I mean, it is not always appreciated by the public, but it is not an excuse, just because it is engineering, that you can be vague. In a way, you've got to be more rigorous --

MR. MALLAY: True.

MEMBER WALLIS: -- but in a different way.

MR. MALLAY: Uh-huh, right. Well, we are very proud of the model, especially after we went through these 139, or whatever it was, validation cases.

MEMBER WALLIS: Yes, the statistical treatment was very nice, yes. I guess our discussion, the trouble we have with your documentation was with other parts of it.

MR. MALLAY: Yes.

MEMBER WALLIS: And I've got one final remark. I think you have been very lucky that you are relying to a large extent on 30 years of experience with the RELAP-type codes, which have evolved and have been shown to be useful. Therefore, one could perhaps say, well, why do we have to go back and re-examine the roots of them? But I think you are lucky in that way, that if you came in with a new code and said, "This is the way we treat things. We don't have 30 years of experience, but whatever we did it seems to work," you would be in much more trouble, I think.

MR. MALLAY: Uh-hum. Thank you. Again, I appreciate the support of the Subcommittee and also the time of the full Committee.

MEMBER RANSOM: I would like to offer one comment that has to do with, I think some of these questions could be answered easily by proper choice of simple problems that you might run that demonstrate the characteristics of not only the basic equations you are using, but the final product, which is the code. These would be things like variable area and passage of Ts, where the momentum flux terms and their treatment has been questioned.

In those cases I think it is a way of showing that the code is or is not reasonable in idealized problems. A manometer is another example, as a matter of fact. You get the frequency correct and the amplitude correct. These can go a long ways towards proving not only the basic formulation, but the numerics and the way it is implemented finally, and nodalization, as a matter of fact, can be addressed in those kinds of problems, too.

I don't think that is an awful lot of work. It may be some, but it is a way of showing in fairly, idealized problems that you do get the correct behavior or you don't.

MEMBER WALLIS: I think if I were a manager, I would require that my engineers do this with simple problems before they launched off and solved reactor problems.

MR. MALLAY: Thank you.

MEMBER WALLIS: Thank you very much.

Are there any other points or questions from the Committee? We seem to have caught up on time maybe.

MEMBER SHACK: If you were to requalify this on a different platform, do I run the 59 cases? Is that what I run?

MR. O'DELL: This is Larry O'Dell with Framatome.

No, you actually are, I think, requalified on another platform. As a minimum, you would have to convince yourself that what you have done for the uncertainties and bias generation was correct. I would say you would have to rerun those. You would have to basically rerun at least a subset of all of the assessments to show that the new platform or the new compiler and what it had done with the code didn't surprise you in some fashion.

Basically, running all those cases isn't the real problem. The real problem is then I have to document them all and I have to QA them all, so that I've got an Appendix B-qualified trail as I moved.

MEMBER WALLIS: Any more questions for Framatome?

(No response.)

We move ahead to a presentation by the staff. I notice there is kind of a reversal of the roles. Usually, industry comes in with beautiful colored slides, and the staff comes in with something more primitive, but here it seems to be the other way around.

MR. LANDRY: The wonders of modern technology.

MEMBER POWERS: They can run on clusters.

(Laughter.)

MR. LANDRY: Thank you, Dr. Wallis. My name is Ralph Landry. I am the lead engineer on the staff of the review of S-RELAP5.

This morning -- no, it is this afternoon now -- this afternoon I would like to go over a little bit of what the staff did and review the code and what we have put into the SER, how we structured our SER.

What I thought I would do is very briefly discuss a couple of the milestones in the review and mention who the review team is and some of the review results and our conclusions.

The team was five people: myself and Sarah Colpo, Tony Attard, Yuri Orechwa on the staff, and Lynn Ward at ISL Laboratories. The others aren't here. They managed to get out of town and are all on travel today.

(Laughter.)

Whether that is a good thing or not, it remains to be seen because they are all in Canada.

(Laughter.)

They are all at the Chalk River, and it was snowing at Chalk River in September.

(Laughter.)

MEMBER POWERS: It's a permanent state, I think.

(Laughter.)

MR. LANDRY: That's like upper Minnesota; they have 11 months of winter and 1 one month of bad sledding.

(Laughter.)

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.)