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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

MATERIALS AND METALLURGY AND PLANT OPERATIONS

SUBCOMMITTEES

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VHP CRACKING AND RPV HEAD DEGRADATION

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WEDNESDAY,

APRIL 23, 2003

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The Subcommittee met in the Commissioner's Conference Room (O-1G16), 11545 Rockville Pike, Rockville, Maryland, at 8L30 a.m., F. Peter Ford and John D. Sieber, Co-Chairmen, presiding.

PRESENT:

F. PETER FORD	CO-CHAIRMAN
JOHN D. SIEBER	CO-CHAIRMAN
THOMAS S. KRESS	MEMBER
STEPHEN L. ROSEN	MEMBER
WILLIAM J. SHACK	MEMBER
GRAHAM B. WALLIS	MEMBER
MAGGALEAN W. WESTON	STAFF ENGINEER

SPEAKERS:

ALLEN HISER	NRR
BRENDAN MORONEY	NRR
CAYETANO SANTOS	NRR

A G E N D A

P R O C E E D I N G S

(8:31 a.m.)

CHAIRMAN FORD: The meeting will now come to order. This is the second day of the meeting of the ACRS Joint Subcommittees on Materials and Metallurgy and on Plant Operations. I'm Peter Ford, Chairman of Materials and Metallurgy Subcommittee. My Co-Chair is Jack Sieber, Chairman of the Plant Operations Subcommittee.

Mag, I notice that most people in the room, in fact all of them in the room were here yesterday, so I would suggest that we don't go through all of the things. Yesterday, we covered presentations from Arlington Industry and some from NRC Research. Today we're concentrating on presentations from the reactor vessel head inspections from Allen Hiser, and also some work on the LLTF results. Allen. Any comments from the Committee Members before we start? I shall be asking the Committee Members for advice to the NRC for their presentation at the Full Committee next month.

MR. HISER: Good morning. I'm Allen Hiser with Materials and Chemical Engineering Branch of NRR. If you want to go to the next slide, Steve. Two days ago I thought this was going to be about eight or ten slides, but what I've done is tried to pull together a lot of information from the last two refueling outage inspection seasons that I think have some significant results that you guys might be interested in, a lot of photos from some of the visual inspections and things like that.

What I want to do first of all though is go through some background. There was some talk yesterday about where we've been the last two years, a little over two years. And what I want to do is go through some of the more significant findings, and where the NRC has interjected itself with various communications, bulletins and the order. I would endorse what Larry said yesterday that, you know, this has been predominantly a reactive mode. Unfortunately, I think we're still in that mode a little bit with some of the findings at South Texas and Sequoyah. We'll talk about that in a little bit.

After going through backgrounds, I want to go through in some detail the orders that we issued two months ago in terms of the inspection requirements, and then describe some of the relaxation requests that we've received, and show some graphics that illustrate some of the issues that have been raised in some of the inspections. Then I want to go through some recent plan experience dating back to last fall with photos and things like that. Then finally, I want to look forward to where we think we will be with this issue in the regulatory framework over the next few years. And then I want to -- the last slide is sort of a bone to industry, with just some things that we've been involved with them on, and just some ideas on activities that we think that they need to be involved in.

So flipping to the next slide, Slide 3, within the United States, the main inspection findings really started in the Fall of 2000, when Oconee Unit 1 identified deposits, and identified a nozzle with an axial leak. The next season, Spring 2001, well, this is when we became aware of the existence of problems. Unfortunately, we keep -- the industry keeps finding more problems as they look more and more, and that trend will probably continue. But then in the Spring 2001, the first identification of circumferential cracks occurred at Oconee Unit 2 and Oconee Unit 3. To alleviate any concerns that this was an Oconee only problem, ANO Unit 1 identified a leaking nozzle in that same season. The NRC, in August 2001, issued a bulletin that was focused on the safety issue, mainly identification, prevention of circumferential cracks, and the emphasis of the bulletin was really on high susceptibility plants.

And to take it a step further, at that point in time, the accepted inspection approach was visual inspections of the top of the head. For the most part, these had never been performed before on plants, and I think many licensees were surprised at the items that they identified on their head from Boron, from canoseal leaks, flange leaks, things like that, to washers, screws and things like that from the original --

MEMBER SHACK: But that surprises me a little bit. I mean, ever since 9701 weren't they doing visual inspections looking for the hundreds of pounds of Boron?

MR. HISER: I think the hundreds of pounds of Boron were generally looked for on the flange area as a downstream location outside of the insulation. I'm not aware that there was a significant effort at doing bare metal visual, and maybe Larry can comment on that.

MR. MATTHEWS: My recollection is that most of the B&W plants were doing some type of inspection on top of the head, but most of the other plants were looking at the insulation and outside the insulation. They weren't looking at --

MR. HISER: And I guess in at least one case that visual wasn't implemented very well, so the NRC issued this bulletin in 2001, August, 2001. Again, the emphasis was high susceptibility plants trying to determine whether there were other plants that had this issue with circumferential cracking.

In response to the bulletin, there were numerous bare metal visual inspections implemented. In the fall, two additional plants identified circumferential cracking. I guess one new plant and one old plant that first identified circumferential cracking in the spring now found an additional nozzle with a circumferential crack in the fall.

In addition, so now we're away from cir cracks only being at Oconee. Now we've pulled in Crystal River. At this point, all the leakage, all the cracks have been identified in B&W plants. Surry, North Anna Unit 2 identified leaks, did repairs, and now we're outside of the B&W plants.

If we go to the next slide, page 4, as we're all aware, about a year ago, Davis-Besse identified head wastage, and in addition, they identified at least one nozzle that had a circumferential crack. In response to that finding, the NRC issued a bulletin in March of 2002, and in this case, the focus was on the safety issue of RPV head wastage. And this was the cracking issue again. We thought we had some sort of an idea on susceptibility so we had a priority ranking of plants, high susceptibility, moderate, low susceptibility. The concern that we identified here was that head wastage may not be tied necessarily to nozzle leakage, which is tied to susceptibility, but it could come from other sources. You know, Boron from leaking CRDM flanges, canoseals, canopy seals, you know, as we found last fall. Other things, such as RVLIS valves above the head, so this bulletin really encompassed the entire PWR industry, all 69 plants. There was no easy way to segregate the plants from --

MEMBER WALLIS: This is just RPV, it's not the primary circuit. It's not the pressurizer, for instance.

MR. HISER: Well, at this point, there really were two emphases. One was on the head wastage and a separate part of the bulletin addressed the rest of the RCS. And the review of that is actually still ongoing, and if you want more information on that, we can provide that later.

CHAIRMAN FORD: Allen, I wonder if you

could educate me. As I understand it, the monitoring aspect of this up to this point was leakage rate, which I understand the technical specification is one gallon a minute. And I also understand that that is based on allowable leakage rates coming from steam generators.

CHAIRMAN SIEBER: It's based on what you can detect, because it's done -- the leakage is determined by doing a water balance.

CHAIRMAN FORD: Well, could you comment -- my French friends keep telling -- I recognize I keep plugging this, but they do have a long experience, so keep plugging it, one gallon per minute tech spec for leakage rate is inappropriate for vessel head penetrations. And they use acoustic monitors, et cetera. Now has there been any thought process as to why they've changed their tech specs, as regards to leakage rates in the head, and the monitorings that they use? Has any thought been put to that?

MR. HISER: Well, yeah. We have had some discussions with them. I think everybody in the United States would agree that one GPM is not appropriate to the vessel head, the upper head or the lower head. You look at --

CHAIRMAN FORD: The reason why I bring

that up, I remember when Davis-Besse, giving a presentation and they said oh, that was all right because it was within the tech spec.

MR. HISER: Well, it's within tech spec but there also are tech specs that say no reactor coolant pressure boundary leakage, which you guys discussed a little bit yesterday.

MEMBER WALLIS: One GPM is over a thousand gallons a day. You think you'd find that somewhere. It doesn't just disappear.

MR. HISER: Well, I think most of it ends up --

MEMBER WALLIS: Well, the Boron doesn't disappear. I mean, the steam does.

MR. HISER: Yeah. The water shows up in various ways, in condensers, containment coolers.

CHAIRMAN FORD: I guess -- I'm not trying to put you on the line, Allen. I'm just asking the question for curiosity, that if other people who operate a large number of PWRs, I understand have changed that tech spec as it applies to the vessel head penetration, and have put in monitoring devices to control to a much lower rate. We haven't thought along those lines at all. Is that correct?

MR. HISER: No. I think we've thought

about those lines, and I think in the Lessons Learned Task Force presentation this afternoon, you'll hear more about the activities that we have to address that.

CHAIRMAN FORD: Great.

MR. HISER: One of the concerns though is that the leak rate is not -- that you get from nozzle penetrations is not one GPM, it's not a tenth of a GPM. It's on the order, at least from Oconee, ten to the minus six GPM. That's a pretty small number, and I'm not sure that there is any sensing, monitoring that would enable you to identify that. This is -- I think what we found is that these head penetrations are very sensitive. The leakage just is not very high, an additional attention is needed. Exactly what form that takes, I think the -- and once the Lessons Learned Task Force Action Plan is implemented, I think we'll get to some reasonable answers on that.

CHAIRMAN FORD: Someone in NRC has gone down that thought process.

MR. HISER: Well, I think at this point, we have a process to go down that path. That's exactly right.

MEMBER SHACK: Allen, as part of this -- I mean, did anybody discover any other serious defects in Boric Acid control programs and inspections, and reports? Not just the RPV wastage, but I assume people were looking at other aspects of the Boric Acid control programs.

MR. HISER: Yeah, there is a large effort that is looking at the programs that licensees have implemented. We're doing audits at a few plants to see how they have implemented what they've described on paper. My understanding is that there is a wide variety of plans. Some of very robust, very aggressive. I think South Texas described to us that their findings on their lower head were part of their normal Generic Letter 88-05 inspection. Not many plants had that sort of access, so there is a variety of programs, implementations, access. If you do want more information, there is other staff that's working more involved in that area, so if that would be of interest, we can arrange for some information on that.

MEMBER SHACK: It's of interest to me. I mean, it seems to me there was a serious breakdown in their 88-05 program at Davis-Besse.

MR. HISER: I think -- my understanding is that the findings from Bulletin 2002-01 from the Request for Additional Information, the audits, I think overall the programs are being implemented in a fairly rigorous consistent manner. I think part of the problem is that there may be differences in the scope of the programs in terms of, you know, going under insulation, having various access opportunities at some plants, so there may be a wide variety of results that one can get. So that is one of the areas that I know other staff is looking at, is trying to determine what best practices are, and try to overall upgrade the qualities inspections and these programs to a common level. Okay?

After the NRC -- after we issued Bulletin 2002-01, in that same inspection season, Millstone identified part through- wall cracks in several nozzles and did repairs. This was the first CE plant that found cracking.

In response to -- so pretty much the state-of-the-art at that point, last summer we issued Bulletin 2002-02. Hopefully, as you'll see, the bar is being raised a little bit as we issue these bulletins. The focus this time was the overall inspection programs for the head predominantly, not the bulk of the RCS, mainly looking at the inspection methods that were being implemented, and the frequency of inspections in particular for high susceptibility plants. The bulletin was providing guidance that non-visual NDE is necessary, and for high susceptibility plants in particular, frequent non-visual NDE.

Now the licensee responses were generally vague on -- not so much on the next refueling outage, but subsequent inspections. There weren't a lot of commitments to any specific inspections or frequencies. And many licensees cited the MRP-75 Program.

CHAIRMAN FORD: Now just to turn back to the MRP-75 Program, there was an initial one which has been not formally reviewed by you because it was withdrawn. Is that correct?

MR. HISER: That's correct.

CHAIRMAN FORD: I think you mentioned yesterday that on the revised REV-1 of the MRP-75, the second version, you have received that and you are reviewing it?

MR. HISER: No.

CHAIRMAN FORD: Is that correct? No.

MR. HISER: No. The -- I think zero is the current revision. Correct, Larry? I'm getting MRP-55 and 75.

MR. MATTHEWS: Yeah.

MR. HISER: One of them we already had --

MR. MATTHEW: I may be getting them mixed up too, but it seems like the first one we sent in was dubbed REV-1, because just publication issues.

CHAIRMAN FORD: Well, the one I'm referring to --

MR. MATTHEWS: They have not received the revised one. That's what we intend to try to get to the staff by the end of the summer.

CHAIRMAN FORD: Okay. And the original MRP-75 which you started and then stopped, was the one that we heard about in the summer of last year.

MR. MATTHEWS: Yes.

CHAIRMAN FORD: You presented this idea of inspection periodicities. Okay. So that's been withdrawn, and you're about to get a revised version.

MR. MATTHEWS: It should probably -- the main reason it was withdraw was that it was based on the premise that a visual inspection was completely adequate, and North Anna 2 kind of brought that into question in the Fall of `02.

MEMBER WALLIS: Are you folks concerned with the precision and sensitivity, and so on of these inspection methods?

MR. HISER: Yes. Clearly.

MEMBER WALLIS: I think that would be very important.

MR. HISER: Yes.

CHAIRMAN FORD: Will you be talking about that, because remember yesterday we showed some concern about quantification of the techniques in terms of sensitivity, real versus observed, and the question of the qualification of the inspectors. And will you be talking that at all today?

MR. HISER: I don't have plans to talk about that. I think sort of to summarize, I think as the industry representatives pointed out yesterday, that statistics really aren't there to do any formal POD calculations.

CHAIRMAN FORD: I think several of the members are roughly coming around to the conclusion that the key to this -- the management of this whole issue is adequate inspection at adequate timing. And the timing aspect comes under MRP-75 arguments. The technique --

MR. HISER: Right now it comes out of the order.

CHAIRMAN FORD: Correct. But the technique, you know, we need to understand. We need to understand how well qualified are those techniques, and who is qualified.

MR. HISER: Yeah. I think the state-of-the-art, the ability to quantify will improve. I think at the present time, we believe that the inspections are effective, and are appropriate. Clearly, there will be room for improvement. We can maybe talk about presenting some information in the future.

CHAIRMAN FORD: Well, maybe at the -- because if you say it's adequate and appropriate are rather qualitative phrases.

MR. HISER: Yes. Okay. If you turn to slide 5, this past fall had several new findings, if you will. North Anna Unit 2 identified prevalent weld cracking in the J-groove welds. They did find a leak from a repaired nozzle, and I do have some information on that, that I'd like to share with you later. And in addition, as Larry pointed out yesterday, in at least one, and I guess several nozzles, there appears to be circumferential cracking on the OD of the nozzles at or below the weld groove, without Boron deposits on the head. And clearly, this is a structurally very significant location. If that crack were to propagate sufficiently, then you could end up with a nozzle ejection sort of event.

In addition, last fall, ANO Unit 1

identified the leak from a repaired nozzle. I have some information on that, on how that repair was made and the location of the probable leak path. Similarly to North Anna 2, Oconee Unit 2 identified nozzles, or at least one nozzle I guess that had through-wall cracking, and apparently path from the inside of the RCS to the outside, but there were no deposits, Boron deposits on the RPV head.

MEMBER WALLIS: Was it leaking?

MR. HISER: I don't believe -- no, there were no deposits visible on the head.

MEMBER WALLIS: You say it wasn't leaking, it's not clear to me -- you might not have certain cracks that, as I said yesterday, would spit out the Boron in some other form that you wouldn't actually see on the head. It could actually be carried out in the steam as particles or something.

MR. HISER: This is the first nozzle that I'm aware of that the industry has identified as from the MDE measurements, you would conclude that it has a through-wall leak path, but no deposits on the head, so I'm not -- at least from experience to date and with many of the high susceptibility plants at this point, they have performed NDE of 100 percent of their nozzles. So this is -- this may be a quirk of the ultrasonic uncertainty, or it may be that we have some sort of a new phenomenon going on. Unfortunately, before this was identified as a potential issue, the repair had been made, and the material was machined away, so we don't have -- other than the UT data, there really is not a good way to go back and do additional work on this.

In addition, at the Sequoyah Unit 2 facility, there was upper head corrosion identified. And in this case, the source was not nozzle leaks, but it was from a source above the head. And again on this, I want to show you some photos later that go into a little bit more detail on that.

MEMBER WALLIS: These research programs, are they trying to figure out why it's popcorn, or why it's spaghetti, or what other forms the Boron might take from a leak?

MR. HISER: I'm not aware that the NRC research is looking at that.

MEMBER WALLIS: Is there someone looking at the various forms that Boron could take from a leak? It seems to me, assuming -- first of all, we thought it was popcorn, then we see spaghetti, and there could be all sorts of other ways in which the Boron could form and could go someplace.

MR. HISER: Yeah. I'm not aware that our Office of Research is doing anything in that area.

MEMBER WALLIS: I think you should monitor what's going on. So you're not aware that industry is doing something similar?

MR. HISER: I'm not aware of any work that the industry is doing. As far as the NRC is concerned, we want to avoid leaks. We think that's the --

MEMBER WALLIS: So basically, you assume that if there was a leak you'd see Boron popcorn. This is a question that we've raised before.

MR. HISER: I think the assumption maybe at this point is not that popcorn would be the evidence, but you would see some sort of record of Boron on the head. And again not to jump ahead, but there are some findings at North Anna Unit 1 that I want to talk about later, of maybe a transition in the form of the Boron deposit on the head from one cycle to another. And I think two years ago, we thought popcorn was really what the industry should look for. I think as we're finding now, almost any sort of deposit requires some additional attention to determine whether there is a leak path.

MEMBER ROSEN: Allen, have we got

sufficient regulatory controls in place now to prevent the disturbing phenomenon of people finding leaks and destroying the evidence with repairs and so on? Have we got enough in place to make people pause and let us look at this thing? We're in the middle of a research program. We don't want this stuff disturbed before we get our arms around it, and decide how to look at things.

MR. HISER: At this point, we don't have any regulatory ability to prevent them from doing repairs.

MEMBER ROSEN: And disturbing the evidence.

MR. HISER: And disturbing, destroying, yes. We had a commitment a year and a half ago from Davis-Besse that if they identified cracks, they would take all reasonable measures to preserve the evidence, if you will. Well, when it came time to do the repairs they found that there were no convenient measures to preserve the evidence, and so it was destroyed. It's -- what it really comes down to I think is an economic decision by licensees.

MEMBER ROSEN: Well, we can help them with that decision. Right? With enough regulatory --

MR. HISER: At this point, I don't think

that there is a sufficient regulatory, I won't say interest, but for an individual licensee it's not sufficiently in their interest to --

MEMBER ROSEN: Well, I see that as a weakness of our program.

MR. HISER: I would not disagree. I think -- in all honesty, I think --

MEMBER KRESS: They would never pass it back to them though. And it's not a compliance issue, I don't think.

MR. HISER: I'm sure Larry would agree, as well, that we would love to have more information on all of these leaks, and cracks, and things, because it makes our job easier, it makes the industry's job a lot easier. The more information, the better you can understand and hopefully be able to predict what's going to happen next. We're somewhat hamstrung by that, but we do have other regulatory requirements that intercede, such as backfit.

Okay. Then this past February, the NRC did issue an order, February 11th, and that provides specific inspection requirements for all PWRs. The next few slides, I'll go through the various parameters and requirements in the order. More recently, this past spring, we continue to see new things. Sequoyah Unit 1 identified a Boron deposit on a nozzle or at a nozzle. Sequoyah Unit 1 is a low susceptibility plant. I believe out of 69 plants they're like number 67, something like that. I'll talk more about that, and how they appear to have resolved that finding.

In addition, some discussion yesterday about South Texas Unit 1, Boron deposits on the lower head. Again, this is a low temperature condition. I have some information on the EDY level of that, and how that fits in overall. Okay?

MEMBER ROSEN: Not quite. Could you go back a minute. Is this South Texas situation the first time that Boron deposits have been reported on the lower head anyplace?

MR. HISER: No. There have been several instances of Boron identified on the lower head, or on the insulation below the lower head. One -- probably the most publicized situation at this point is Davis-Besse, where there were streaks of Boron and rust running down the sides of the head onto the lower head.

MEMBER ROSEN: Let me rephrase my question. Is this the first report of Boron deposits on the lower head that came from the lower head?

MR. HISER: This appears to be. This appears to be. Every other instance where Boron has been identified on the lower head, there's been some uncertainty about the source of it. At South Texas, we have been told that there are no streaks or trails that lead from higher elevations down to these nozzles.

MEMBER ROSEN: Now isn't it a little curious to you that a plant with 2 EDY would be the first place to report this?

MR. HISER: There are many things that -- many parts of this that we may not -- you know, they may be plant-specific situations. South Texas did a bypass flow conversion four years ago. The Boron they dated dates back four years. Is there some tie to that? It may be fabrication related. I mean, there are many aspects of this, and that's one of the reasons right now with South Texas we have observations. We don't have any real understanding of where the leakage is coming from, be it from the weld, from the nozzle base material. Is it fabrication related? Is it a stress corrosion cracking sort of mechanism? Is it a fatigue mechanism? Is it vibration related? I mean, there are many possibilities, and the implications of each of those are radically different.

MEMBER WALLIS: But you can date the Boron, so you know when it was deposited.

MR. HISER: Well, we can date the Boron that's available on the surface of the head. The J-groove weld is about 7 inches up inside the head. You have that full length that probably is full of Boron, and we can only sample the surface right now. It may be that the Boron at the top of that annulus may be younger.

MEMBER WALLIS: Based on the stuff inside could be younger.

MR. HISER: Right.

MEMBER WALLIS: Or it could be that it came out four years ago and nothing happened since.

MR. HISER: Given the low leak rates, I would be surprised that you'd get something, and then nothing over four years.

MEMBER WALLIS: In the paper I think yesterday or the day before, somebody from NRC - I've forgotten his name - did report there were no other incidences of bottom head cracking. And I assume he meant in PWRs worldwide. I guess that was based on a fairly extensive look at the operating records worldwide.

MR. HISER: I'm not sure what the basis of that statement would have been.

MEMBER WALLIS: I agree with you. I haven't heard of any, but that doesn't mean to say that --

MR. HISER: Our understanding is that the French have identified some fabrication-related defects.

MEMBER WALLIS: Yes.

MR. HISER: There was a Japanese situation recently. I don't -- I believe they identified that possibly as cracking. It was a very shallow --

MEMBER WALLIS: Yeah, but in relation to the potential unusualness of this event, maybe we need to do a lot more looking into the literature and records before we come to the conclusion that this is a one-off situation, and it could never occur again.

MR. HISER: Well, I'm --

MEMBER WALLIS: I know you didn't say that.

[THE DISCUSSION HAS BEEN REMOVED DUE TO PROPRIETARY INFORMATION]

MEMBER WALLIS: Are there any plans at all within NRR to look at BWR bottom head penetrations --

MR. HISER: I am not --

MEMBER WALLIS: -- which are predominantly operating under hydrogen water chemistry?

MR. HISER: Hopefully sometime later this morning we'll have another staffer who can provide you with an update on the situation with BWRs.

MEMBER WALLIS: Okay. Someone has that. That's fine.

MR. HISER: Yes.

MEMBER WALLIS: Good.

MR. HISER: Okay? If we turn to slide 6, just to -- what I want to do now is just go over the orders, the inspection requirements, and the orders, and some of the reasons that we thought it was necessary to issue orders. The orders were issued February 11th to all PWRs, all 69 plants. The basis was adequate protection. In particular, ASME Code Inspections of the upper head are inadequate, revisions to inspection requirements in the ASME Code are not imminent. I guess maybe what I should say is acceptable revisions. The ASME Code has been considering MRP-75 as the basis for possible revisions, and we have many exceptions to what's in MRP-75 as it was issued last summer. Clearly, RPB head degradation and nozzle cracking pose safety risks if they're not promptly identified and corrected. And I think we have ample evidence of that.

The orders that when we were in the mode of issuing bulletins, bulletins do not have substantial regulatory weight. In effect, what we've done with the bulletins is we've induced commitments from licensees to do voluntary inspections. There were no regulatory teeth to the bulletins. We were able to get many plants to do inspections that they had not intended to do, and I think that's a credit to those plants, maybe a credit to our management's ability induce action from licensees. The basis of the orders was to put clear regulatory weight behind requirements in this area. And I guess just to be clear, as well, we do not intend the orders to be a permanent part of the regulatory structure.

Clearly, the regulations, 10 CFR 50.55a is the appropriate place to put permanent requirements. These orders are interim until we have requirements that we can either reference within 50.55a, or we may have to put in specific requirements in 50.55a. We prefer to endorse ASME Code. If that's not possible, then we'll have to have some alternates to 50.55a.

Turning to the next page, just to outline the requirements in the order, there is a requirement to calculate the effective degradation years as an estimate only of the susceptibility of plants to cracking. We do not perceive EDY as having a very high precision. What it is, is a way to relatively bin plants, to put them into appropriate inspection regimes. Time and temperature are the only two parameters, and it is -- you know, it may be that the first decimal or the digit to the left of the decimal is not very accurate, but I think at this point that we're comfortable with the way that it's binning plants, and with the findings of plants so far.

For high susceptibility plants, the order requires bare metal visual examination at each refueling outage, and also non- visual NDE of each nozzle at each outage. For moderate susceptibility plants, it again calls for bare metal visual and non-visual NDE, but these are at alternating refueling outages. And each moderate susceptibility plant must do one inspection each outage. You can do a bare metal visual this outage, the next time you do non-visual, bare metal non-visual. You have to alternate between the two. You can't do both this time, and then next outage not do anything. We didn't think that was appropriate given the susceptibility of these plants.

For low susceptibility plants, the requirements are scaled down a bit. Bare metal visuals must be completed by the next two refueling outages, and then they are to be repeated every third refueling outage, or every five years thereafter. Non-visual must be completed initially by 2008, so five years from now, and then repeated every fourth refueling outage, or seven years thereafter.

CHAIRMAN FORD: This is a very prescriptive approach, which I guess is the only way you can do it. The only thing that would worry me is waiting two refueling outages before doing a bare metal visual, where we now know that the bare metal visual is not absolutely reliable, given the North Anna experience. Surely, that must be backed up by some fairly sound rationale, i.e., an extreme case, I've got a new head. Doesn't that have to be backed up by some sound reasoning, I would imagine, as to why you would not expect -- beyond the prioritization algorithm.

MR. HISER: Yeah. I think the basis of that is findings to-date, and the low susceptibility of these plants. It's not considered to be a likely event that you'll have a crack --

CHAIRMAN FORD: But the likeliness is based solely on this algorithm, which we are now questioning?

MR. HISER: Well, I think there's -- in terms of binning for the purposes of this order, I don't think that there are a lot of questions that the susceptibility model is a reasonable way to relatively bin the plants, based on that reasonableness, and the experience to-date. I think for the low susceptibility plants, there is a low expectation of findings for leakage. And clearly, as additional inspections are performed, we need to go back and look at that, the assumptions that go into that. That is why the Sequoyah findings earlier this year, South Texas now on the lower head, you know, they have the potential for major upsets to the process that's laid out right now. But with the findings that we have to -date, and I think Bill Cullen's chart yesterday showed that fairly well, you know, the problems have been at high EDY levels, with circumferential cracks, leaks, and many nozzle cracks.

There still are plants up there at high EDY levels that found no cracking. In spite of very intensive inspections of both the welds and the nozzles, they found nothing.

CHAIRMAN FORD: I agree with you that the order, my personal opinion that the order is absolutely appropriate as it was drafted at the time. Since then, we've had Sequoyah, which has now gone away, and we've got South Texas, and we don't know whether it's going to go away or not. If it doesn't go away, then there's a big question on where you stand on these random tables until you know why -- if it does occur.

MR. HISER: Well, that's --

CHAIRMAN FORD: And I'm assuming that you are going through either this talk or the next talk to show how your plan is going to be compliant enough so you can respond to these new phenomena as they occur. Is that in the next talk that we're going to be hearing of your's, just looking through the hand-outs. They are talking about the plan as to where they're going to go?

MR. HISER: Yes.

CHAIRMAN FORD: Correct. Good. Okay, then.

MR. HISER: Yeah, I think that plan though maybe is more forward looking than where these orders are right now.

CHAIRMAN FORD: And that's what I'm looking for.

MR. HISER: We have told the industry, and I think a clear expectation is that as new information becomes available, we may need to revise the orders. And I think that that may take various forms. It may be to relax generically some of the requirements of the orders. For example, the nozzle coverage that's in there right now. It may be that for some classes of plants, that more aggressive inspections may be necessary. But, you know, it more or less is a continuous process, as new information becomes available. Sequoyah became available. What's the impact? What do we need to do to the orders? South Texas, what's the impact? What do we need to do?

I mean, it's sort of hard to speculate because the potential sources, you know, for Sequoyah or south Texas are -- there are too many aspects to it, so in one sense I think we need to let the information mature, let the licensees develop a little bit more information.

For Sequoyah, it appears that there may

not have been nozzle leakage, so all the speculation related to that was for naught. You know, with South Texas, you know, maybe we need to start thinking a little more seriously, but we still need the information. Where is the leakage coming from? Is it fabrication, service-induced? You know, those are the kinds of answers that we can't come up with. The licensee has to be able to develop that information.

MEMBER KRESS: What is your view on the relative safety significance of leak in the instrument tube and the bottom head versus a leak in the control rod drive mechanisms in the top head?

MR. HISER: I'm not a risk person, but I'm told that the risk consequences are much different between the two. On the lower -- and my understanding is that --

MEMBER KRESS: The lower head has a chance of draining the vessel, and interfering with TCCS.

MR. HISER: Right.

MEMBER KRESS: The upper head has a chance of interfering with the control rods and just depressurizing. I think the risk implications are much different.

MR. HISER: The one way it was described to me was that on the upper head, if you are venting steam, you're losing -- you're releasing a lot of energy, and you can depressurize, which allows you to get more water sources to fill the vessel.

MEMBER KRESS: Right.

MR. HISER: On the lower head, you're now draining water. You know, the energy that you're draining out is not --

MEMBER KRESS: How fast can you drain it is an issue.

MR. HISER: Right. So there's -- clearly, the challenges are much different between the two. But again, I'm not a risk person, so I really can't talk in too much detail on that.

MEMBER KRESS: Do you envision potential inspections other than visual of the bottom head?

MR. HISER: At the present time, no U.S. plant has done a non-visual on the lower head.

MEMBER KRESS: It would be hard to do.

MR. HISER: It is difficult. There have been inspections in Europe that we're aware of. It requires substantial dismantling of the core internals to gain access there. For a routine, if you will, 100 percent lower head inspection, there may be different steps you'd want to take versus, for example, for South Texas where two specific nozzles are suspected, and you really need to find out what's going on. It may be that you could apply different approaches to this too. It has not -- the challenge I think is very significant for South Texas, as an example.

But I guess in a similar vane, two and a half years ago, nobody was doing UT inspections of the upper heads, and as conditions warrant, and clearly the inspection requirements and needs have to ramp up to meet the challenges.

MEMBER KRESS: We had an internal discussion on some potential acceptability of leaks, and it seems like it may be more acceptable to actually have a leak at the bottom head than the top head, in the sense of the risk-benefit. Wait for a leak and then fix it, as opposed to look for cracks and fix the cracks before they leak.

MR. HISER: My only concern would be that how far -- how close can you approach margins of safety before you're able to identify the issue? If, for example, one or two lower head nozzle ejections or failures could lead you to an undesirable, significantly undesirable state. You need to make sure that you have sufficient margin time-wise between when you would get to that potential ejection condition, and you're able to identify it.

I think one major problem with the lower head is you have a small diameter nozzle, a thinner wall. Assuming equal crack growth rates, which clearly isn't the case if you're at much lower temperature, although you may have stress issue -- I mean, there may be a lot of specific issues on the lower head. I'm not sure that I'd want to go out and say that leakage on the lower head is not as significant as on the upper head, because of those kinds of considerations. What you want is a lot of time margin from identifying to potential accident conditions, and I'm not -- I don't know that we understand the lower head enough to understand how those parameters fit together, how much leakage you get from cracks and things like that. There are a lo of areas we haven't looked at.

MEMBER WALLIS: Well, what are the requirements for inspecting the lower head?

MR. HISER: ASME Code says that you, in effect, look at accessible areas. For many plants, they have insulation. It's - -

MEMBER WALLIS: The Boron, management --

MR. HISER: It's for identification of leakage and normally Boron deposits are the first sign.

MEMBER WALLIS: There's no NRC, there's no new NRC requirement.

MR. HISER: At the present time, there's nothing. It is one of the things that has been on our radar with our interactions with the industry. The upper head issues and new findings, you know, every six months outage after outage has really preoccupied us to focus on that area. South Texas, if confirmed, is service-induced cracking that would be -- have a significant impact on what we're doing.

MEMBER WALLIS: Well, I guess when this started, we said you can bring out these orders. Have you thought about what your response would be if you started to find various things, and I think the response was well, we'll sort that out when we get the evidence.

MR. HISER: Right.

MEMBER WALLIS: Rather than thinking ahead, that if we find something, this is what we're going to do.

MR. HISER: Well, I think people have in their own minds what would be appropriate actions. But again, we need to have an understanding of what's going on. I think to just have sort of a knee-jerk reaction is not appropriate overall.

MEMBER WALLIS: No, but it might be worth it if we could figure it out ahead of time, is all. Maybe you don't even want to tell us what you've thought out ahead of time. It's a bit like the war and the peace. When you fight the war, you have to think about peace, so you've got to think ahead as to what you're going to do when situations develop.

MR. HISER: The bottom of this slide we talked earlier about non-visual NDE. And maybe, Steve, if you go to the next picture, it's not real clear. Unfortunately, it's in color but it's not showing up real well. Yeah, it's sort of hard to see the green area.

The bare metal visual inspection again covers the entire upper head surface, sort of as illustrated there.

MEMBER WALLIS: It doesn't cover the tube though. You sort of just look at the head. You don't look at what's going on along the tube? I think that would be interesting too, if something is running down, or something is spraying up, or anything. You ought to look at the tube.

MR. HISER: Well, I think it's a natural consequence that you look at the tube when you look at the head. I mean, it's hard to avoid that. If you look at some of the videos from the remote inspections, you see pretty much everything. You see the insulation. I mean, you can get a real good understanding of what's going on. But, you know, just to illustrate the area that's covered by the bare metal visual, then the ultrasonic inspection area really is the inside diameter of the tube itself. The order specifies two inches above the J-groove weld down to the bottom, and the order also indicates that you do -- that you look for cracks in the nozzle base material, and you also have to do an evaluation of leakage through the interference fit zone, as a reminder that interference fit zone is located above the J- groove weld.

Then the other alternative is a wetted surface inspection, and it's nice to see if you can see it in color. The red area is again two inches above the J-groove weld down to the bottom, on the ID of the nozzle, the OD of the nozzle up to the weld, and then the surface of the J-groove weld is covered by that.

MEMBER ROSEN: What keeps the wetted surface area limited to just two inches above the weld?

MR. HISER: That is the area that has --

that covers the highest stresses from the J-groove weld. Beyond -- actually, a little bit less, at two inches the stresses are almost zero.

MEMBER ROSEN: But it's wet above that.

MR. HISER: Yeah.

MEMBER ROSEN: Well, it says "wetted surface" inspection, but the wetness goes all the way up, obviously.

MR. HISER: Yeah, absolutely. But in terms of the significant area for this cracking issue, two inches above the weld encompasses all the areas of concern. But I guess the one point to make is that the UT does not cover the J-groove weld, because it addresses cracking in the nozzle base material itself. It provides an assessment of whether there is leakage from the J- groove weld. For example, if you have a weld crack that's just broken through and started to leak, you may not have deposits on the top of the head, but you, in effect, already have a leak starting. This leakage assessment provides sort of a precursor indication of whether you have leakage through the J-groove weld.

MEMBER SHACK: But again, how would you see that in the UT?

MR. HISER: You see a pattern through the interference fit zone that is --

MEMBER SHACK: Looking at the back reflection.

MR. HISER: Right. And that is a topic all on its own on that. We've had a lot of discussions with --

MEMBER SHACK: How about reliability of inspection, reliability of detection of a leak path.

MR. HISER: Our understanding is that nozzles that have had deposits on the head, they've identified leak paths in every case. It is not a standardized demonstrated approach, but it does provide additional information about the condition of the weld, without doing a direct examination of the weld.

MEMBER SHACK: But is the guy looking for -- every time he does the UT, he's looking for a leak path also? He's looking for his cracked tip reflection, obviously, but he's also doing an inspection for a leak path?

MR. HISER: Absolutely. Yes. Under the requirements of the order, they have to be able to make that assessment. Now there are some nozzles, such as the head vent line, that does not have an interference fit. It has a clearance fit for the whole length of it. What licensees have done at leakage assessment, is that they've done PTs of the J-groove weld to demonstrate the integrity of the weld.

MEMBER SHACK: Suppose he does the UT, and he can't see a leak path. Does he then have to go back and do a wet metal exam of the J-groove weld?

MR. HISER: Not by the requirements of the order. But for a nozzle like the vent line that does not have an interference fit, you can't do that leak path assessment, so you need to do that leak assessment through an alternative means, Pts or eddy current of the J-groove weld is one way to do that.

MEMBER SHACK: If he can't establish a leak path, why doesn't he have to go back and do that?

MR. HISER: If you cannot?

MEMBER SHACK: Yeah. I mean, I assume --

MR. HISER: Well, if you've interrogated that area and do not find the characteristic signature, so you appear to have metal-to-metal contact, then it's not -- I mean, you've demonstrated that there is no leakage through that area.

MEMBER SHACK: Well, the argument is that the leakage creates a path, not that you're demonstrating there is a path for leakage so that if you had a leak you would see a leak.

MR. HISER: Right.

MEMBER SHACK: That's not what you're demonstrating. You're arguing that you've somehow got some pseudo erosion of the --

MR. HISER: Erosion deposits, corrosion of the ferritic head. Many possibilities. We've looked at this in fairly good detail. We really need to look at it in much greater detail at this point.

If we turn to the next page, there are explicit requirements and criteria in the order for inspection of repaired nozzles and welds. There may be certain ASME requirements that would indicate that you would not have to look at those, but the order explicitly calls that out as a requirement. In addition, in response to the Sequoyah findings last fall of above-head Boron source, each licensee at each refueling outage must look above the head to identify possible Boric Acid leaks. If they do find something coming down, then they have to do some follow-up inspections of potentially effected head areas and nozzles, which is to ensure that there aren't any adverse effects. Again, I'll have some photos from Sequoyah that will point out some surprises, I think, that were not anticipated.

Flaw evaluation is per -- as described in the order is per NRC guidance. In particular, a letter from Jack Strosnider to NEI dated Fall, 2001. In addition, two weeks ago, we issued a revised set of guidance, and I believe that's consistent pretty much in detail with the ASME Code. Like I say, they recently passed requirements for flaw evaluation. This is consistent with that, although there are a few places within this document that we've issued that we explicitly say that repairs are necessary, whereas the ASME Code leaves it as to subject to interaction between the licensee and the regulator.

CHAIRMAN FORD: The velocity K-curve that's given in this letter, the Jack Strosnider letter, is that the same as the MRP?

MR. HISER: That's the 75-50 MRP curve.

CHAIRMAN FORD: Okay.

MR. HISER: And I think what's described in the cover letter is that the staff has not completed its review of MRP 55, so that would be subject to modification should we find it necessary to do that. At the present time, we think that's the best representation of crack growth.

MS. WESTON: You all have copies of the letter from yesterday.

MR. HISER: Okay. One thing that caused a little bit of stir I think in the industry, is that the order requirements are applicable to new heads, as well. That includes Alloy 600 nozzle heads, such as the one that Davis-Besse has put on, and also the Alloy 690 heads that North Anna 2, North Anna 1, and over the next several years probably about two dozen plants will have one on their heads. And I think there was a lot of discussion yesterday about the staff position on that, the need for additional information to support specific orders for Alloy 690 heads. In addition, 60 days after restart, plants are required to provide a post outage report with details of their inspection findings.

Turning to the next page, licensees do have various options in responding to the order. The first item is already passed. Within 20 days they could request a hearing, or request a time extension to respond. No licensee did that. All 69 provided responses indicating that they would implement the order, as written.

Licensees can request the Director of NRR to relax or rescind specific requirements of the order. WE'll talk about that a little bit later with the requests that we've had for relaxation at this point in time. Those relaxation requests are being handled using the same process that we use for ASME Code reliefs, but there are some specific changes to that. As an example, our Office of General Counsel has indicated that licensees must have relaxation approvals in-hand before restart. That's a difference from relief requests, where we're able to get verbal reliefs.

One of the questions we've gotten from many quarters is why did you guys need to issue orders? As I talked about earlier, the past process of regulating by bulletins really wasn't effective. It didn't have the regulatory weight. In some cases, it was inconsistent because we didn't have clear requirements. Licensees may come in and say we're going to do what the bulletin says. Other licensees may come in with a lesser program, that still provided some relevant information, so we had a little bit of inconsistency. Frankly, it was a very unstable environment, issuing three bulletins over the course of a little over 12 months.

In addition, rule-making to implement changes to 50.55a takes time. If we knew right now what we wanted to put in 50.55a, it wouldn't be in place for probably a minimum of two years. And orders have the regulatory weight. They also have some flexibility to them. They can be revised or rescinded as necessary, presumably not on a frequent basis. But, for example, if we have new findings from spring outages, we could modify the orders as appropriate to address those findings.

In addition, based on Bulletin 2000-202 responses, the inspection plans for the next refueling outages were generally acceptable, but the out years beyond that, there was a lot of uncertainty as to what the requirements would be. What we've done with these orders is provided a clear field so that licensees can plan their inspections. There's no uncertainty at this point of is the NRC going to issue another order, or another bulletin. Can we modify things? The orders provide clear requirements.

In addition, a new item that wasn't addressed by the prior bulletins was head leakage or leakage from above the RPV head from flanges, canoseals, or any other components up there that could cause undetected RPV head degradation. The orders clearly address that, and have specific requirements in that area.

Now the next stage, and for the next several pages I want to describe some of the relaxation requests that we've been presented with, that show some graphics, just illustrating the kinds of issues that licensees have had. There have been limitations to nozzle access, both above the J-groove weld and below the J-groove weld. Above the weld, there are various features. One plant in particular had centering tabs, and a step in the diameter of the nozzle above the weld. Steve, if you put up the next page, this just shows what we're talking about in this area.

This is again above the weld. The specific area is called a sleeve expansion point. The curly area is in the annulus between the nozzle, which is on the left, and the thermal guide sleeves, which is in the middle. These expansion points have really two parts. One is that they directly preclude instrument insertion above that area. In addition, there's a step in the nozzle inside diameter below there that prevents coupling of the transducer to the nozzle, so that creates, in effect, an inability to inspect above that area.

Now there is one recourse for this sort of a condition. You can remove the thermal guide sleeve. You can use a different transducer that doesn't have -- that is not affected by those limits. However, in the case of this plant, the dose requirements to implement that were astronomical. This plant shut down February 14th. The bulletin was issued three days earlier, so there were various hardships associated with that. The staff looked at the stresses in the area that would not be inspected, looked at crack growth for hypothetical cracks in that uninspected portion, and we concluded it was acceptable for them not to inspect.

CHAIRMAN FORD: Is that dimple that I see in the left- hand side of the sleeve, is that hydraulically applied? Is that achieved -- how is that fabricated? The reason why I'm asking, it looks awfully like the stress corrosion sample involving dimples on specimens, created a stress raiser, cold --

MR. HISER: I believe that's a piece that's on the guide sleeve itself. And it's sort of forced in. I think the way the licensee described it, it's sort of screwed in to get it located at the proper elevation, so it's purely a mechanical -- I'm not aware that it was hydraulically, you know -- I'm not certain of that. I don't know. Larry, do you have any --

MR. MATTHEWS: I'm not familiar with -- I believe it's just a centering mechanism that probably is going around to keep that centered in the --

MR. HISER: Right.

MR. MATTHEWS: I believe it's just a centering mechanism to keep the thermal sleeve centered in the nozzle, because the thermal sleeve really provides some guidance for the drive shaft for the control rod. And on a lot of the Westinghouse designed units, there's a tab that's welded on the outside of the thermal sleeve. I'm not sure how their's is put in, whether it's a press-out in the stainless steel.

MEMBER WALLIS: I hope the record shows centered, not sintered, because we don't get to edit the record.

MR. MATTHEWS: Centering, with a center, C-E-N-T-E-R.

MR. WALLIS: With your accent, they sound the same.

MEMBER KRESS: In Alabama, they're pronounced the same.

MR. HISER: This is one case. As Larry mentioned, there are other plants that have centering tabs that similarly restrict access above the weld. And in actuality, one of Larry's plants, Farley, had centering tabs. They prevented in some cases access to and above the weld.

MR. MATTHEWS: Actually, Farley had centering rings which were completely 360 around, and prevented any access up in there with a blade probe, so we had to remove the thermal.

CHAIRMAN FORD: But there was analysis done if this failed, by whatever mechanism. The risk would be small.

MR. HISER: I'm sorry?

CHAIRMAN FORD: If the -- I mean, we've having a lot of discussion about what this is, and no one seems to know specifically what it is in this room. But I'm assuming that analysis was done, if it failed by whatever mechanisms.

MR. HISER: The sleeve expansion point?

CHAIRMAN FORD: Yes.

MR. HISER: We have not considered that. This is a very -- the licensee in this case, this created problems because the thermal guide sleeve was so rigid that they had difficulty in gaining access to their probe 360 around then nozzle, so I don't think that there are any questions of the robustness of that aspect of the assembly.

MR. SIMS: This is William Sims. The thermal sleeve itself is not part of the pressure boundary, so if you had any crack or anything to go with that, that wouldn't be a safety significant issue anyway.

MR. MATTHEWS: And if it failed, all that would happen was that lower part of the thermal sleeves would -- and it wouldn't really be a loose part. It would be captured by the drive shaft on the control. I guess the worst potential I can imagine is flock in one control room.

MR. HISER: But you can see, as well, with the funnel on the bottom of the guide sleeve, getting the probe up into that annulus, the annulus in this case is about 175 mils, so it's -- I think Larry or maybe Tom yesterday used the analogy of a venetian blind, and that's about what these things are. They have a lot of flexibility, very thin member to gain access through a torturous path, but also to be able to provide some spring action to get the transducer under the nozzle, so that you can get data.

Okay. Go back to slide 12, and we'll end up flipping back and forth a little bit. In addition, there are limitations below the J-groove weld. There again, some of these guide funnels, instead of on a separate sleeve, in some cases are mounted in CRDM nozzle itself. There's threads on the ID, on the OD, and in addition, at least one plant has identified some tapers on the end of the nozzle.

In addition, with plants that are using the time-of- flight diffraction approach, the arrangement of the transducers is such that you end up not inspecting part of the bottom of the nozzle. Steve, if you flip maybe to page 14. Thank you.

This is a case in point where there are external threads on the nozzle for the guide funnel. In addition, there's a taper on the ID. Gaining ultrasonic data in this area is meaningless, because you don't know how to interpret the results. In this case, the stresses down in this part of the nozzle tend to be very low, so it really is not -- does not have any quality or safety implications of not inspecting that portion.

This is another plant. In this case, these threads were located at least one inch beyond the weld, that provided the licensee for a good opportunity to demonstrate what the stress is, and significance of not inspecting that area are.

Finally, page 16. This is hard to see. It's better on the screen, I think. This is a schematic arrangement of sensors for time-of-flight diffraction measurement. We have two transducers.

The sound beam comes out at an angle from this transducer, for example, is captured here. There's this part, this triangular part of the nozzle that you can't see with this arrangement. Going back a little bit to Tom Alley's description yesterday of the inspections, this arrangement would be really sensitive to circumferential cracks, and that's generally what a lot of licensees have applied.

Again, this area is a low stress area. If you assumed a hypothetical crack, the crack doesn't grow very far in the one cycle that the plant would be operating. So in general in these cases, even if there is a hypothetical crack here that grows, when you do your next inspection, you'd identify it up in this portion before it would get to the pressure boundary, so there is margin from that standpoint.

And if you go back again, Steve, bare metal visual inspections are also an area that we've had one relief request submitted, and an inquiry about another one. Actually, several. In some cases, they're localized insulation and support shroud interferences that preclude access to 100 percent of the head. These are generally outside of the head area beyond where the CRDM nozzles are, so the -- what licensees have proposed in this case is to examine the head above the interference, that there's no source of Boron, at that point no leakage, then look below the interference. Again, if there's no source of Boron, then you have confidence that the integrity of the head in that area is in tact. So that would be for a localized situation.

MEMBER ROSEN: I don't understand.

MR. HISER: Okay. See, maybe if we flipped to this. This is a different example, but as an example, if the support, the shroud support structure comes down and intersects the head at this point, you really can't inspect the head right under that. But you do an inspection of the rest of the head, including all reasonable sources of leakage, for example, through the nozzles. There really is no source of leakage at the support structure itself, so if you looked above, you know, uphill of it, and there's nothing uphill, it's flowing down under the support structure, and there's nothing below the support structure that indicates that, you know, for whatever reason you have a source of leakage. You have assurance that there's nothing going on in the head under that structure.

MEMBER ROSEN: Well, for instance -- I understand that logic for that specific location, but what about for the uphill locations where all that insulation is right up against the head? How is that inspected?

MR. HISER: Okay. For the other situations such as this, where insulation is directly on the head, has a very limited access overall. In this case, the licensee has proposed to take ultrasonic measurements from the ID of the head, through the head thickness to determine or confirm that the head has integrity. So, for example, if the head is supposed to be six and a half inches thick, they'll take a map of the entire head 360 around to demonstrate integrity of the head. They're coupling that with ultrasonic measurements of the ID of the nozzles, looking for cracks through the nozzles, looking for a leak path. If there's no leak paths through the nozzles, if they can confirm that there's no leakage source from above, you don't have any way to get Boron on the head to cause corrosion. That's the sort of argument that they're putting forth.

MEMBER ROSEN: There's no way to remove sections of that insulation package to confirm, to get the bare metal visual in some locations, to provide confirmation that that technique is adequate? I mean, I believe all of that, but it would be nice if I could take off a place which is presumably clean based on those things and say yeah, indeed, there it is. Clean just as we've said.

MR. HISER: I don't believe that this licensee has proposed any visual inspection because of the access. I'm not sure what the exact arrangement of the insulation here is, but there -- some plants have removed insulation similar to this. It is, in effect, asbestos block. There are concerns with the asbestos abatement, and they have to replace it with some other form of insulation. In some cases, blanket insulation. In general, licensees are making modifications to their insulation, but again the planning process to be able to implement that is what, in effect, creates a hardship for them.

MEMBER KRESS: Do you have any concerns Boric Acid crystals sitting on top of the head?

MR. HISER: It depends on where they're from, and whether you stop the source.

MEMBER KRESS: No, not talking about the source. I know that's a concern, but from the fact that Boron crystals corroding or eating away the head itself.

MR. HISER: I think our experience has been that if the Boron is dry, that it may create very minimal corrosion, where you have a source of water, and I think Davis-Besse is the A- number one exhibit, as well, when I talk about Sequoyah findings from last fall, I think they're a very strong indication, as well, that if you have wet Boron, you can develop problems fairly rapidly.

MEMBER KRESS: So the purpose of the ultrasonic, validating the thickness of that head is in case you have a Davis-Besse problem somewhere.

MR. HISER: Well, in case you have unanticipated conditions that exist. As Dr. Rosen mentioned, you know, scientifically all that fits together and makes sense, but if there's, you know, some unanticipated hole in the logic, then maybe there's a leakage source up here that you're not able to identify. Then there's ultrasonic measurements just to provide confirmation that you, you know, a Davis-Besse issue, or any other sort of an issue ongoing. Davis-Besse was a specific manifestation. I think as was mentioned yesterday by Bill Cullen, it was another nozzle at Davis-Besse that leaked, that had a very small corrosion area pretty much in the center of the head. Looking at the top of the head really isn't going to tell you that that's ongoing necessarily. As you get corrosion, you do end up with volume increases so, you know, the metal has to go -- the corroded metal has to go somewhere. Normally, that's going to be up and be visible but, you know, the proposal by this licensee takes some of that uncertainty out of the way by making direct measurements of what the head thickness is.

CHAIRMAN FORD: Is this the only licensee who's made this sort of application?

MR. HISER: Only one licensee has submitted a request at this point. We've had discussions with another licensee, that I believe may have a similar insulation arrangement.

CHAIRMAN FORD: I had the impression this is a fairly common insulation arrangement.

MR. HISER: Numerous licensees have been pulling their insulation off, have been abating -- you know, they have asbestos, various problems. Some have been doing that. Several, as an example, Point Beach and Kewaunee, in particular, they've removed their conforming insulation and have replaced it with blankets that is more -- you know, then they just pull the blankets off to do the visual inspection.

CHAIRMAN FORD: So there are not that many plants left who've got this particular problem.

MR. HISER: There are numerous plants that still have challenges. You know, this is sort of an extreme situation. There are other situations that require highly specialized equipment, and I think the licensees would say good luck, you know, in that their insulation isn't compressed in some way that it could limit access to the head.

CHAIRMAN FORD: How many of those plants are moderate susceptibility plants?

MR. HISER: I'm not sure. I'd have to go back and check. I'm not sure that we have full knowledge at this point of every licensee that's modified their insulation. But, you know, we are aware that those steps are being taken, you know. In addition, now that we're in order space, licensees need to do bare metal visuals every outage if they're high susceptibility. That creates a real strong incentive to modify the insulation to make it easier to do that kind of an inspection.

MEMBER ROSEN: What unit is that?

MR. HISER: Yeah, I think it's 2.

MR. SIMS: Going back to the question about the other plant, the other plant that's in a similar situation, that was ANO 2. Both these plants are CE plants, and they are unique. And if you look at the way the design of the top of the CRDM nozzles are, they're basically, the flanges conform to the top of the head, instead of like the B&W plants, some of those, all the flanges are up above. And so the insulation for these and the shroud for this plant and Arkansas ANO-2 is stair step. And that shroud basically goes underneath the motor housing, so I can't pick it up and pull that insulation out. There's only a couple of inches or so gap between the shroud and the insulation itself.

We're looking and trying to figure out a way to pull that insulation off, but thus far we have not been successful to figure that out with anything that's reasonable. It looks like in order to be able to do that, we would have to pull the motor housing and everything completely out, and tear it apart piece by piece. And then we're going to have to come up with some method of putting new insulation on there that we could remove on a cycle-by-cycle basis. And it's not an easy task.

MEMBER KRESS: Can you put the insulation on the inside?

MR. HISER: Do what now?

MEMBER KRESS: Put the insulation on the inside of the dome?

CHAIRMAN SIEBER: Good idea.

MR. SIMS: That would be a good idea. It would be easier to get to. No, but right now, it is -- you might be able to destroy it, get it out without completely disassembling the head. But then to put something back in is -- we haven't figured that out as yet either, so we're looking at alternative options as opposed to bare metal exam at this point.

CHAIRMAN SIEBER: Well, you don't have a lot of clearance there anyway.

MR. SIMS: You what?

CHAIRMAN SIEBER: You don't have a lot of clearance between the head vessel itself and the motor housing anyway.

MR. SIMS: That's correct. Yeah, even if I tried to lift it, I can't lift it maybe an inch or so before it hits the bottom of the motor housing.

MR. HISER: And there are other plants that don't have this extreme condition, that when we were in bulletin space again, it was -- you know, they were doing more best effort bare metal visuals, and they were able to lift in some cases the insulation sufficiently that they could gain access. And there were some licensees that again thought they were fairly fortunate in being able to do that.

In general, we have -- I think some of the hardship arguments hold water at the present time for Spring, 2003 outages, because licensees clearly didn't have time to put the assets in place, and do their planning. For Fall, 2003 and subsequent outages, I think the pieces may be a little bit harder to make because the requirements are there in the order, as of February 11th. Okay. Steve, if you'd flip to page 18.

MEMBER WALLIS: I'm just thinking, when you make these orders, are you aware that there are going to be these restraints?

MR. HISER: We're aware that there are issues. We're also mindful of what's necessary to demonstrate quality and safety.

MEMBER WALLIS: If you issue an order which is impossible to fulfill because of these restraints, it's a strange kind of order.

MR. HISER: Well, the -- we have numerous plants with a variety of situations and conditions. And I think what we've done within the orders is set down what we think is necessary from an inspection standpoint. If a licensee is able to demonstrate either (a) that there is no impact on quality and safety by not doing a part of the inspections required by the order, or (b) that there's a sufficient hardship, that there's no commensurate increase in the level of quality and safety by doing the inspection, then the order allows us to provide relaxation in those cases. You know, the intent is not to issue orders that are impossible to fulfill. You know, it's really intended to provide the inspections that are necessary to demonstrate quality and safety.

CHAIRMAN SIEBER: Actually, you're better off allowing the licensee to do his own engineering, and solve his interference problems to try to comply with the order, than for you to make a custom order for them, and then give no relief.

MR. HISER: Right.

CHAIRMAN SIEBER: That would be a disaster.

MEMBER WALLIS: But you could have emphasized more the kind of inspection where possible, maybe these ultrasonic make the visual less important or something.

MR. HISER: Well, I think that one of the points we made within the order is that the visual and non-visual really go hand-and-glove. There was discussion yesterday about probability of detection and things like that. The non-visual NDE is not perfect, and that's why the visual is a good complimentary approach, you know, not that one or the other is sufficient, but they work together very well. And I think one of the things that we're finding, the order did say to inspect from two inches above the J-groove weld down to the bottom of the nozzle. And clearly, what we're finding is some consistent limitations on that, for example, at the bottom of the nozzles. The next two pages provide the relaxation requests that have been received to-date. And again, a lot of them are the bottom of the nozzle where the stresses are low, and there just are inherent geometric restrictions.

I guess one relaxation request that I just want to mention, Turkey Point, a high susceptibility plant, had two nozzles that are called for RVLMS, Reactor Vessel Level Monitoring System. How high is the water in the vessel? These nozzles provided unique difficulties to them because they have the four inch diameter CRDM nozzle, but then they had a plate welded on the bottom that supported the Reactor Vessel Level Monitoring equipment. They demonstrated or indicated that there was a hardship due to dose, and having to, in effect, grind off those welds, do the inspection, and then re-weld the head plate back on. They applied for relaxation. We were ready to approve that. We had a couple of conditions that we thought were necessary. They ultimately decided to withdraw their request, and so that relaxation did not go in place.

I think other than that, for the most part, relaxations have been fairly minor, looking at the ends of the nozzles for the most part. Millstone Unit-2 is probably going to be the most challenging one that we're going to deal with in the short term. They're the one that wanted to make the UT measurements from under the head.

MEMBER SHACK: Just how many UT measurements are they proposing?

MR. HISER: They talked about a map. They have some sort of UT device on what they called a sled that they're just going to roam all over. We have sort of the bare description that they provided to-date. We do have a request for additional information that we've sent to them. I expect that we're going to have numerous interactions to understand the physical geometry of what they're doing, what potential problems could be. We have concerns.

Steve, if you go back to 17 for a minute. For example, one concern we have is that, you know, ultrasonics likes to hit surfaces at 90 degree angles. If I'm now inspecting here, how do I inspect the downhill nozzle, the downhill side of that nozzle? Those are the kinds of things that we need to understand before we grant that relaxation. This would be -- to my mind, this would be a big deal approving this one. The others are sort of, you know, around the edges. This would be a major perturbation from the order.

CHAIRMAN FORD: So the request has been put in, but it hasn't been approved on Millstone.

MR. HISER: No, it has not been approved. Millstone, their outage is this fall, and they would like a response from us very soon whether we will grant this relaxation or not, so that they can take other measures if we're not going to approve it. At this point, I'd say we have about 2 percent of the information that we need to make that decision, so we have a lot of interaction that we're going to need to have with them. Okay. Steve, if you --

CHAIRMAN FORD: Are you about to go into North Anna now?

MR. HISER: Yeah, I think so.

CHAIRMAN FORD: What I would suggest is that since you're about to start a whole new topic area, well a relatively new topic area, let's take a break for 15 minutes now, and we'll resume.

MR. HISER: Okay.

CHAIRMAN FORD: So we're going to recess until 20 past 10.

(Whereupon, the proceeding in the above-entitled matter went off the record at 10:05:16 a.m. and went back on the record at 10:22:26 a.m.)

CHAIRMAN FORD: Okay. Let's come back into session. I have been asking the last couple of days, concerned whether there's proven indications on BWR bottom head penetrations, and we've got Ms. Mina Connor, who is just going to interrupt Al's presentation just to address this issue. So, Mina, thank you.

MS. CONNOR: Okay. I was asked to address the BWR, the lower plenum internal components, just to see what's going on with the BWRs. I put together some background stuff. You probably already know a lot of this, but I'll just try to briefly run through it as quickly as possible.

Okay. For the BWR lower plenum internal components, there is a topical report. That's BWRVIP-47, and that's called "BWR Lower Plenum Inspection and Valuation Guidelines." It provides a history of inspection data, inspection guidelines for the lower plenum internal components.

When they were putting together this report, they did a lot of field inspections, and from those inspections, the BWRVIP review of the field cracking data indicated that with the exception of Nine Mile Point and Oyster Creek, they have step tubes at Oyster Creek and Nine Mile Point. Basically, besides those exceptions, the lower plenum components were not experiencing significant field cracking at all.

And in regards to Oyster Creek and Nine Mile Point, there is a VIP report, that's 17, that addresses weld expansion repair. We haven't approved that generically. That's an ongoing issue, and actually the licensees are trying to get that code approved right now as far as the weld expansion -- as permanent repair, but right now as a temporary repair we have approved it for Nine Mile Point and Oyster Creek.

CHAIRMAN FORD: VIP-47 has been approved.

MS. CONNOR: Well, actually we've done the initial review on that. We've got several open items, and we've already talked to them. We've discussed all those open items, and they're just going to revise the report to address our concerns, which are mostly clarifications.

CHAIRMAN FORD: Now if I remember rightly, VIP-47 only reviews United States experience.

MS. CONNOR: That'S right.

CHAIRMAN FORD: There have been head cracking indications abroad, in Japan, for instance.

MS. CONNOR: Right. We've seen that a lot lately.

CHAIRMAN FORD: But that is not reflected in this report.

MS. CONNOR: It's not, but then again, the Japan plants do belong to the BWR VIP, but they have not -- you're correct, they did not address the Japanese plants at all.

CHAIRMAN FORD: Okay. And also the Swedish plants too, there have been inspections. In fact, positive in the terms that they have not found cracking.

MS. CONNOR: Right. I think the ones that I'm aware of are the problems that they've experienced with Japanese plants. I think they deal with those separately, but definitely, whatever is approved that the BWRVIP guidelines, they are to follow them, because they are a part of the BWRVIP. Okay.

Before I address inspections, the largest concern is really IGSEC, and what they're going to be doing, what they have been doing is following Generic Letter 88-01 so they do all the inspections in accordance with Generic Letter 88-01. They have several, I mean, many reports, many guidelines on IGSEC but, you know, what we've approved in Generic Letter 88-01 is definitely what they're following.

Okay. All of the inspections that they do are -- whatever is required by ASME Code, they are following, so all of the visual inspections that are required to be performed under the CRD guide-tubes, stub tubes and in-core housings are done in accordance with ASME Code Section 11. The instrument penetrations are pressured-tested. Visual inspections are also performed --

CHAIRMAN FORD: Excuse me. Pressure-tested when?

MS. CONNOR: AT normal operating conditions. And they're done -- all of this is done during refueling outages, but they will do -- once they're getting ready to come up, then they will do them. Okay.

CHAIRMAN FORD: 1.2?

CHAIRMAN SIEBER: Actually, the hydro is

1.2.

CHAIRMAN FORD: Well, the reason why I'm asking is that if they're pressure-tested, how sure are we that we're going to see a leak? If it's not over-pressure-tested, then is that going to be any indication of whether you've got a through weld penetration?

MS. CONNOR: Okay. I --

CHAIRMAN FORD: Is there any information on that?

MS. CONNOR: I really wouldn't know. I can definitely find out. I'll take that as a note, and get back to you.

CHAIRMAN SIEBER: I think the distinction that can be made is hydrostatic tests for code are designed to test the structural integrity of the vessel itself; whereas, the design pressure-test, and that's 1.2 - design pressure-test is 1.0. And that does not prove structural integrity from the bulk standpoint. It will show leaks. Just the flow rate is a little smaller.

MS. CONNOR: Okay.

CHAIRMAN FORD: Okay.

MS. CONNOR: Okay. I'll definitely confirm that and get back to you guys on that.

MEMBER WALLIS: Whether it's a hot or a cold test doesn't make any difference to the flow rate.

MEMBER SHACK: Well, I mean leaks from cracks are also very sensitive to the pressure. I mean, it's a non-linear relationship because you're opening it.

MS. CONNOR: Okay.

CHAIRMAN FORD: Therefore, if the pressure testing is done at pressure, at the operating pressure, then how much leeway do we have before, in fact -- and you'll see presumably very little leakage. How much leeway do we have before you would see appreciable leakage of safety margin, safety margin to be defined as to when you get a through-wall weld leak.

MEMBER WALLIS: Yeah. If it's the sort of leak we're talking about, you have to wait for months before you build up a deposit. If you just pressure test and look at it for a few minutes, you won't see anything at all.

MR. SHACK: You wait a long time in a BWR for a deposit.

CHAIRMAN FORD: Just glancing through the rest of your presentation, you make no indication of the various designs that exist for bottom head penetrations in BWR2s up to the 6s. And some of them, as you know, involve 600 step tubes running to weld, attachment weld to the stainless steel tube. That lack of distinction in your presentation, does that detract anything from your conclusions?

MS. CONNOR: No, but I mean, as far as the inspection findings, what I did -- what I was going to discuss also was they have inspection summary reports that they put out. And what we did was we looked at all the lower vessel components findings, and there were very few. And that's where we come to the conclusion, you know, and so there have been no indications on those. That's why I didn't really separate the review.

Okay. So let me just continue. The GE SIL 409, for some reason they found a lot of cracking with the drive tubes. Almost every single plant has had problems with the drive tubes and as I was stating, pre-VIP-47, they did a lot of inspections. And mostly, they were finding crackings in these dry tubes, so they put out a GE SIL 409, and they're required to do a BT-1 on the dry tubes. Most of them have been replaced, so they haven't been having that many problems.

CHAIRMAN FORD: What did they do to no longer have the problem?

MS. CONNOR: They're just replacing them.

CHAIRMAN FORD: The same --

MS. CONNOR: No, I'm sorry. A different modification, but that is a different material. It's a little -- it's a different design and modification on the drive tubes.

CHAIRMAN FORD: Okay. So they went to steel with low carbs content?

MS. CONNOR: I really don't know. I know that they did make material differences, material composition differences, and there's supposed to be also a different design. I don't know the exact details on that.

CHAIRMAN FORD: Okay.

MS. CONNOR: But they haven't had problems since they've been replacing them. Okay. In addition to VIP-47 -- I'm sorry. In addition to the ASME Code requirements, that the BWRVIP do on these components, they also added a few other weld inspections, and this was -- all these were basically added as a result of the inspection findings that they found. So for the CRD guide tube sleeve to alignment lug weld, they're doing BT-3, and this is done at every refueling outage. I'm sorry. They've got an inspection frequency, and a scope, and sample size that is recommended through VIP-47. Basically, it's a 12 year frequency where they're supposed to inspect 10 percent of a population of these. And for the CRD guide tube body to sleeve weld and CRD guide base to body weld they do an EBT-1 which is a .5 mil wire. And the guide tube and fuel support alignment pin-to-core plate weld and pin, they do a BT-3 on that. And the bottom just says that the BWRVIP-47 provides recommendations of sample size, frequency, acceptance criteria for the inspection of those welds.

CHAIRMAN FORD: Just to confirm, because of the construction of these, the main structural weld is on the inside of the pressure vessel which is hard to get to, so these --

MS. CONNOR: Right. This is all based on accessibility, if they can get --

CHAIRMAN FORD: Pardon?

MS. CONNOR: This is all based -- everything is based on accessibility. They do have a statement in the report that says that, you know, they will not remove -- if they're easily accessible, then they will do these inspections. If they need to -- they will not remove components to get to other components.

CHAIRMAN FORD: Now apart from -- there's a full scope inspection Oscoshan several years ago where they drained the vessel and did a complete internal examination. As far as I remember, all the bottom penetrations. Do you know if any other similar inspection has occurred? That's only one population. That's one of a very large population, with a negative result. Any other?

MS. CONNOR: I'm not aware. You know, I can definitely -- I've got contacts I can call. Okay. Keep in mind that a few of these walls I just previously discussed are pressure boundary walls, and ASME Code requirements do apply. That was actually one of the open items that we had asked them to address in the BWRVIP report.

Okay. What we did was every year the BWRVIP submits to us their inspection report summaries, a commitment that they made to us, so in reviewing them, you know, we kind of focused on the lower plenum components to see what type of results they've been getting, if they found indications, and they were very minor. I'll just go through them really quick.

For Dresden in 1994, there was one dry

tube that was identified to be cracked. That was replaced, and that was found in accordance with the inspection requirements of GE SIL, or recommendations of GE SIL-409. Oyster Creek, as I indicated before, those step tubes that are sensitized, they found two step tubes that were leaking at the bottom head. A UT was performed of the CRD housings to the step tube walls in the area of the housing to be rolled. No reportable indications were found, and the roll repaired both of the leaking housings. For Browns Ferry Unit 2, same type of thing. The dry tubes were inspected, cracking was found and the tubes were replaced. So as you can see, you know, we haven't found any major indications, any cracking indications of the lower plenum components, so we feel pretty assured that the inspections that they have recommended through VIP-47 are, you know, pretty in tact.

Okay. Then I just put a page together regarding the safety consequence, inspection experience, accessibility. BWRs, you know, they did -- if cracking was to be found at the CRD in core-housing welds, you really don't have a large safety significance consequence because they don't affect the CRD insertion. Even if cracking were to be found, the potential for CRD ejection is eliminated because they have a shoot-out steel that comes out to protect the coats from coming down. So, therefore, CRD insertability is not challenged. In addition, they've got the Boron injection. They've got the additional redundancy of the Boron injection if failure of CRD insertion were to occur.

MEMBER ROSEN: The shoot-out steel, is this the grid underneath the housing that prevents the housing from coming down?

MS. CONNOR: Exactly. Yeah. It's a kind of strange name, but that's right.

MEMBER KRESS: When you say safety significance, you're talking design-basis base.

MS. CONNOR: Right.

MEMBER KRESS: Have there been any risk implications?

MS. CONNOR: Not that I know of. I don't think there are. We're pretty assured that --

MEMBER KRESS: Probably not because the small break LOCA wouldn't add much to the initiating event frequency. And I don't think it would interfere with the water source several accident, you know, they rely -- in risk-base they credit for the water control rod drives as part of the ECS, but it doesn't look like it would be a risk.

MS. CONNOR: I don't think so. Okay. If cracking is significant and leads to leakage, then it would be detected immediately, and appropriate correction action is taken immediately with BWRs. And as you all know, they're getting ready to implement -- these BWRs in the BWRVIP Program are getting ready to implement hydrogen water chemistry, if they haven't already. Also, there's noble metal chemical addition that's going to be implemented, and we agree that the actual susceptibility will be expected to drop quite significantly.

So basically in conclusion, just in view of the field history and the significant inspection experience, we feel that what the BWRVIP has been doing is, you know, definitely -- they're doing what's required by code, and then they've implemented other inspections as we discussed on those welds, so we really feel assured that we're comfortable with what they're doing. And we will continue to review their inspection response. Okay.

CHAIRMAN FORD: Could I ask the members -- this is one of these situations that we asked about, being sensitive to the reactive nature of this whole problem, another problem coming up, another problem coming up. This is an obvious one to address. Do you get the feeling right now that this is one that you can relax on before going onto other topics?

MEMBER KRESS: I certainly do.

MEMBER SHACK: I had a question about the leakage detected immediately. I mean, it's just water in my 5 GPM. I mean, why would I detect it immediately? There's no special leakage detection system here, is there?

MS. CONNOR: No. I think they're just really on any leaks they would visually see them from the inspections. And before anything would occur, any major thing would occur, they would detect them. They would be taken, and corrective action would be taken immediately.

MR. SHACK: Okay. I mean, it's our normal kind of leak before break.

MS. CONNOR: Right. Exactly.

MEMBER ROSEN: And these dry wells have leak detection in the sumps, and they monitor --

MS. CONNOR: They monitor them frequently. Right.

MEMBER ROSEN: I'm just not familiar with the BWR sump arrangement. Are the tech specs the same as or similar to the PWR tech specs, where you have a level for unidentified leakage, and another level for identified leakage?

MS. CONNOR: You know, we checked for Oyster Creek and Nine Mile Point when we were looking to approve the weld expansion criteria. They are allowed leakage, because they have the old tech specs, so for those two plants, I know that we have checked, and they're in accordance with the old tech specs. They're not with the new improved tech specs, so they are allowed some leakage.

MEMBER ROSEN: And the new improved tech specs say what?

MS. CONNOR: Say no allowable. Right. No leakage.

MEMBER ROSEN: How is that detected during normal operation?

MS. CONNOR: They've got monitor -- they do detect them through the monitors. They've got the -- as far as I know, they've got monitors that they use to detect leakage.

MEMBER ROSEN: Monitors. Under the vessel?

MS. CONNOR: You know, I really don't know, to be honest. I can find out. I haven't gotten -- I know about the tech specs, but I really haven't gotten into detail about how they detect the leak.

MEMBER SHACK: No unidentified leakage?

MS. CONNOR: Yeah, it would be -- they are allowed -- with the old tech specs they are allowed to have -- let me say this right. They are allowed leakage. They are allowed to have leakage with the old tech specs for those two plants because those are old tech specs.

MEMBER ROSEN: Yeah. Well, I would be interested in what the dry well leakage monitoring systems are currently in service in the BWRs. I just don't recall that. I used to know.

CHAIRMAN FORD: Mina, would you mind following up on that and getting back to Ms. Weston?

MS. CONNOR: Sure. That would be no problem. Right. Okay.

CHAIRMAN FORD: Thank you very much indeed. You've put our minds somewhat at rest, at least. Thank you.

MS. CONNOR: Thank you.

CHAIRMAN FORD: Al, thanks for accommodating that.

MR. HISER: Appreciate Mina stepping up with that. I guess pretty much of the presentation, I want to go over some of the recent findings, some of the photos and things. And also then at the end, look forward to the future with some outlook on where we think this is going.

As indicated here, North Anna 2 had an inspection this past fall. A little bit of history, Fall, 2001, the same unit did a visual inspection, identified some leaks. They were repaired. A year later identified more leaks. One of the leaks was at one of the nozzles that they had repaired in Fall, 2001. What they found was that the repair did not cover the original Alloy 182 buttering, and actually if you flip to page 21, Steve, there's a schematic that shows what that looks like, which indicated in the inner donut area, if you will, is the repair that was made. What they've identified is then that some of the original 182 weld material or the buttering was left exposed to the environment, and indications were identified in that buttering in this area.

I'm not sure that these have positively been determined to be a leak source, but these were new indications that they did not find when they did the original repair. Intent of this repair was to cover all of the 182. In this case, and as we'll see -- well, in this case at North Anna Unit 2, that didn't happen, so there were repair deficiencies identified.

MEMBER SHACK: Has anybody else tried this J-weld weld butter repair?

MR. HISER: The overlay repair has been accomplished, as well, at ANO 1. Is that the only one, Terrance?

MR. CHAN: So far, I think.

MR. HISER: Okay. I think there's another plant that has implemented this.

MEMBER SHACK: And everybody uses it as a repair rather than a proactive thing to prevent --

MR. HISER: They've all been repairs, repairs of leaking nozzles. In addition, at North Anna, as was discussed yesterday, there were numerous weld indications identified, and ultimately the licensee decided to replace the head with a brand new head with Alloy 690 nozzles.

CHAIRMAN FORD: And 52 weld?

MR. HISER: Yes. This is an EDF head fabricated to the French code. In addition, ANO Unit 1 this past fall did an inspection of the head, identified a leak on the RPV head at a repaired nozzle indicated here. Unfortunately, it doesn't come across real well. This is sort of the classic popcorn Boric Acid that was coming out of this nozzle. And I guess, Steve, if you flip to page 24, this is an illustration of the repair that they did.

MEMBER ROSEN: Look up above, Allen.

MR. HISER: Yeah. That's probably better. This was the repair area from -- it was repaired I guess a year and a half ago, Spring of 2001. In this case, the original weld material was left exposed, and just sort of a plug was applied to the weld.

Numerous indications are identified around the circumference or the interface of the original weld and the new weld. This was, I believe, one of the first repairs that was performed on a CRDM, the first that used an overlay approach, in particular. And at the present time, this would not be the kind of approach that this vendor would -- or kind of repair that the vendor would use. They would want to encapsulate the entire weld with 152 or 52.

CHAIRMAN FORD: So RI means what?

MR. HISER: Reportable Indication.

MEMBER ROSEN: Now what do they do when they do a repair like that? Do they chase the crack as far down as it goes by grinding first?

MR. HISER: I believe on this one that they did not chase the flaws at all.

MR. SIMS: With that particular nozzle we ground all the way down to the butter. We ground all of the weld material out where the indication was found. And then we did a PT, and then found we'd PT cleared at the bottom of it, to make sure there were no indications.

MEMBER ROSEN: Then you built it back up.

MR. SIMS: Then we built it back up with 52 weld material.

MEMBER ROSEN: How did you leave the surface when you were done?

MR. SIMS: Ground it smooth and PT.

MEMBER ROSEN: Okay. Thank you.

CHAIRMAN FORD: Just so we understand, everything that is orange/green up the -- this region here is the original weld.

MR. HISER: Right. This represents the as-found condition.

CHAIRMAN FORD: And when you say "butter", I always think of butter, as something you put on top. That is, in fact, the actual weld.

MR. HISER: Well, the butter is placed on the vessel head itself after machining the weld prep. Then the head is -- once the butter is put down, then the head is stress relieved.

CHAIRMAN FORD: I'm sorry. I see now that the arrow is going to this region.

MR. HISER: Right.

CHAIRMAN FORD: Okay.

MR. HISER: It's a concentric area.

MEMBER ROSEN: So go over it for me, Allen, make sure I understand.

MR. HISER: The butter is --

CHAIRMAN FORD: You may have to look at your -- and this may go off a minute.

MR. HISER: Well, maybe we can do it up here. The weld prep is machined into the head. Then the butter is applied. Head is stress relieved, and then the weld -- the nozzle is inserted and the weld, J-groove weld is applied.

CHAIRMAN FORD: And you put an 82 groove weld, and a 182 top weld. Is that right?

MR. HISER: I'm not sure what the --

CHAIRMAN FORD: They put a weld and then they put down the 182 on top of it. Is that the normal way?

MR. SIMS: That's probably the way. I'm not sure. I'd have to go back and look at the records.

MR. HISER: It depends on early plant, older plant, these kinds of things, as well.

MR. SIMS: Yeah.

MEMBER ROSEN: How do you stress relieve the -- I mean, you're talking about a huge head, and you're working on one nozzle of the head.

MR. HISER: Yeah. Every nozzle is machined, buttered, then the whole head is stress relieved.

MEMBER ROSEN: Oh, I see. Take the whole head out to a --

MR. HISER: Right. Then you insert the nozzles, weld the nozzles, and it goes into -- well, I mean, inspections and all. But there's no additional stress relief after the J-groove weld is applied.

MEMBER ROSEN: So this -- the ANO head was removed from the container and taken out to a furnace someplace?

MR. HISER: No, no, no, no. That was the original fabrication.

MEMBER ROSEN: Oh, this was --

MR. HISER: I'm sorry. That was the original, and I think --

MEMBER ROSEN: Okay. I got confused. I thought you were saying you stress relieve the repair.

MR. HISER: No. The -- clarify one thing.

The process that you talked about of grinding down to the butter, was that the initial repair?

MR. SIMS: That was the initial repair.

MR. HISER: What about the repair last fall?

MR. SIMS: The repair last fall was the FDR repair where we basically removed the bottom portion of the nozzle, put a new pressure boundary in.

MEMBER SHACK: But you ground down to the butter, you didn't remove the butter so you didn't have to do a stress relief --

MR. SIMS: That's correct. And when we ground down to the butter, then we did a dye penetrant exam and that was PT clean.

MR. HISER: And that was the main point, just that this sort of patch repair did not hold up.

CHAIRMAN FORD: Patch repair was 52? When you ground out these indications, and you did a -- I know on some of them you did a 52 weld repair.

MR. SIMS: This was a stick weld.

MR. HISER: There's two parts, again. There have been two repairs made to this nozzle. Initially, when this patch was applied, that was 52/ 152 repair. It had no indications left after they ground out. The repair last fall was a different, totally different repair. It was not an overlay repair. It was the repair where they machined the nozzle up into the vessel head, much as Davis-Besse. And then re-weld the head to the vessel or to the nozzle up at that point, so the pressure boundary of the J-groove weld is moved from the J-groove weld up to this new weld. So all of the -- you know, none of this is an integral part of the pressure boundary at this point.

MEMBER SHACK: Do you have a problem that you didn't have to stress relieve that weld?

MR. HISER: No.

MR. SIMS: It's temper made.

MR. ROSEN: It's temper made.

MR. HISER: This has created more uncertainties than I wanted.

CHAIRMAN FORD: I guess what we're trying to work our way through is the sequence of events. And when did stress relieving take place, because that would be relevant to the cracking? And when was 52 applied, and 52/152 weld or weld repair, and has that degraded? I think that's where the line of questioning is going.

MR. HISER: If you want to split it into three parts, the original fabrication, repair one, repair two.

CHAIRMAN FORD: Right.

MR. HISER: The original fabrication is when the butter was stress relieved along with the head.

CHAIRMAN FORD: And never received stress relief thereafter.

MR. HISER: It has not been stress relieved thereafter. The 52/152 was applied to this area.

CHAIRMAN FORD: Right.

MR. HISER: I don't recollect if the licensee did a lot of investigation of these indications. At least from the sketch, it looks like all of them are not -- none of them are in the 52/152 repair material, but just like in the heat effected zone adjacent to it. Maybe there's some sort of a sensitization sort of an effect on the original weld.

CHAIRMAN FORD: Okay.

MEMBER SHACK: Now this is a CE fabrication sequence. The discussion yesterday was in B&W plants, you butter, you install the nozzle, and then you stress relieve?

MR. HISER: No. I don't believe any of the upper heads had a stress relieve of the J-groove weld with the nozzles inserted. The butter -- my understanding is the butter, you know, the process is very -- weld prep, butter, stress relieve the whole head, insert nozzles, weld, as-welded condition is what you have. That's on the upper heads.

What we've been told on the lower heads is that they are stress relieved after nozzles are inserted and welds are applied. That's what we've been told on the lower heads. We need to confirm that that's a universal process.

MEMBER ROSEN: When you say we've been told, are you -- you're referring to on the lower heads that they've been stress relieved. You're referring to the B&W plants, or --

MR. HISER: There was a plant in Texas that told us that a week ago.

MEMBER SHACK: I see.

MR. HISER: And that's our understanding from some of the European experience, as well, where some inspections have been done, that their welds are stress relieved.

MEMBER SHACK: Would they still have a sequence where they do a weld prep, a butter, then install the weld, install the tube weld, and then stress relieve? I mean, is there a butter or it's a direct weld to the vessel?

MR. HISER: I'm not sure.

MEMBER SHACK: It's butter.

CHAIRMAN SIEBER: You would have to stress relieve the entire vessel.

MR. HISER: I'm sure that's when that stress relief occurred.

CHAIRMAN SIEBER: Okay. So the stress relief was really for the plate weld vessel.

MEMBER ROSEN: They get hot too.

MR. HISER: The one thing that was surprising though is that that was -- you know, that the nozzles were inserted before the stress relief. My understanding is one of the reasons that the upper head J-welds are not stress relieved is fear of distortion. And one would have expected the same issues on the bottom, but maybe the tolerances are not as significant.

CHAIRMAN SIEBER: I guess they don't care as much on the bottom as alignment.

MEMBER ROSEN: Then goes through those --

MR. HISER: Yeah.

CHAIRMAN SIEBER: There's a lot of --

MR. HISER: So you just bend those.

CHAIRMAN SIEBER: Well, the sequence of

fabrication then was fortuitous as far as --

MR. HISER: Right.

MR. MATTHEWS: Al, at this point it's not clear to me that all the bottom mounted instruments, nozzles were stress relieved with the vessel. That may be a vessel by vessel thing. We're going to have to -- you know, everybody is going to have to look into. I think some were and some weren't.

MR. HISER: Okay Like everything else, every plant is different.

CHAIRMAN FORD: Go forward.

MR. HISER: Okay. So we'll go passed ANO 1 to Sequoyah Unit 2. What was identified at Sequoyah was a leak from a RVLIS valve, and this is like the RVLMS at Turkey Point we talked about earlier with the relief request, that this is a little bit different. In particular, Boron from this leak impacted the insulation and fell through a seam and onto the RPV head. This is the RVLIS valve itself, leak occurred. You can see the flow pattern, the spray pattern from that. The pile of Boron that was left on the insulation, I think it was on the order of 20 pounds of Boron. I'm not sure how long this leak occurred.

If you flip to the next page, Steve, the upper figure shows the head itself, and clearly down at the flange area, the Boron piled up. It's sort of hard to see because of focus issues, but this is the area that remained after the head was cleaned up. It's sort of hard to get a lot of perspective on that, I guess.

MEMBER WALLIS: Well, the discoloration, the red stuff up there, the proper color there is rust or something, corrosion of some sort.

MR. HISER: Minor surface corrosion.

MEMBER WALLIS: Minor surface.

MR. HISER: Yeah.

MEMBER WALLIS: But the other place is deeper corrosion there.

MR. HISER: Yeah. This area is the main corroded area where the leakage impacted the head.

MEMBER WALLIS: And how deep was that, Allen?

MR. HISER: The licensee said it was a maximum of an eighth of an inch deep, about five inches long in this direction, and really hard to tell, but apparently five-sixteenths of an inch wide, so it was more of a groove than really is indicated here. It's hard to tell.

CHAIRMAN SIEBER: Did they do some kind of repair?

MR. HISER: No, this was found to be acceptable.

MR. HISER: Okay. And this finding, frankly, is what prompted the one provision of the order that licensees have to look for leakage above the head that could impact the vessel head. This is one of those areas that if, for example, the bare metal visual focused only on the area around the nozzles, this could have been missed, because this is far away from where the nozzle area of the head is.

MEMBER ROSEN: Now this is a little off the topic, but the leak from the valve, where did the valve leak? Is that a body leak or a bonnet leak, or was it a bellows leak? Is that bellow seal valve?

MR. HISER: I don't know the details on that.

MEMBER WALLIS: It looks like a leak from where the pipe is attached to the valve.

MR. CHAN: This is Terrance Chan. I'm with the Materials and Chemical Engineering Branch. The leak came from a compression fitting that was not installed -- evidently, it was not installed properly.

MEMBER ROSEN: It's the compression fitting right where the line attaches to the valve?

MR. CHAN: Yes. That's our understanding.

MEMBER ROSEN: Okay. Yeah, it looks like that's where it would be.

CHAIRMAN SIEBER: Actually, it's covered up.

MEMBER ROSEN: Yeah. Well, there's lot of Boron on it.

CHAIRMAN SIEBER: Well, there's this pipe support there too.

MR. HISER: Okay. We move on to North Anna Unit 1. This past spring, history on North Anna Unit 1, this was the first plant to be inspected after issuance of Bulletin 2001-01. You need to zoom out a little bit, Steve. At that time, there were I guess, if you will, suspicions of leakage on this nozzle. If you go ahead and turn to the photographs, this is nozzle number 50, indications of something going on on the head.

North Anna, I believe this was the first time that they'd looked under the insulation of their upper head. They had had significant problems with canoseal leaks. Frankly, they had a lot of Boron on the head. What we found out, as well, is they had very high velocity air moving through the upper head, so there was, you know, spray pretty much going everywhere.

At this point in time, we were expecting to see popcorn. That was the Oconee classic evidence of nozzle leakage. We saw this, and it really wasn't clear to us what was going on there.

MEMBER WALLIS: It looks to be smeared up the tube, the flow is flowing it up the tubes.

MEMBER ROSEN: There's some capillary action of some kind drawing it.

MR. HISER: Yeah. The only photo that seemed to have any sort of volume to it was this one, where maybe you can see something there. Whether that's directly associated with the annulus of the nozzle or, you know, it's wind-blown from one of the canoseal leaks isn't obvious.

The licensee in this case did a UT inspection of the nozzle, came back clean. Did a PT of the J-groove weld, had some indications in the PT that the licensee dispositioned as being out at the clad to the J-groove weld interface, artifacts of the geometry. Region 2 staff and NRR staff agreed with the licensee that it was not necessarily relevant to the nozzle, based on where the indications were, and based on the lack of a clear leak indication on the head.

MEMBER ROSEN: And in the lower left

picture, there's much debris in the back there.

MR. HISER: Yeah.

MEMBER ROSEN: That was considered to be unrelated to it?

MR. HISER: Yes. Yeah, there is a lot of Boron on the head, and I believe this area was more powdery, which is like what you normally see from a high temperature leak, you know, the water flashes, and the Boron just falls out.

MEMBER SHACK: What was the insulation like on this head?

MR. HISER: A horizontal step, so this is part of the insulation here. In this case, the insulation starts off at the top of the head, and then comes down in a step-wise progression like that. Access is not real good. Yeah, you can manipulate it and get there, which clearly they did. So that's what was seen in 2001. If you flip to the next page, zoom out, this is that same nozzle a year and a half later. At this point, the classic popcorn Boron.

MEMBER WALLIS: It also has the streaks, there's a red streak running down from this nozzle.

MR. HISER: From here.

MEMBER WALLIS: That clear one up at the sky there on the projector up on that wall there.

MR. HISER: Yeah, right there.

MEMBER WALLIS: It's much more obvious, red streak.

MR. HISER: Yeah. So if you look back at the 2001 photos, what may have happened is a leak may have occurred fairly late in the cycle, and the Boron concentration is relatively low. It just was not able to provide a full deposit, so I think the capillary action sort of an explanation may be consistent with what this is.

And as with North Anna Unit 2, this head was replaced, not necessarily related to nozzle 50, but just as a preventative measure by the licensee. I guess the only other point to make about that was the visual inspection really only encompassed that one nozzle, because there were some uncertainties, and I guess some allegations regarding the condition of that nozzle. And the licensee did only inspect that one. They did not do a general head inspection, which was unfortunate.

Okay. Last couple of inspections. Sequoyah Unit 1 this past spring, a Boron deposit was identified on the head at nozzle 3. And I think if you go ahead, Steve, and put the photographs up, just really a small area.

MEMBER WALLIS: And it did seem to wick up the wall or something. It's higher on there than the surroundings.

MR. HISER: Really hard to tell. I think this had a 3-D character to it according to the licensee, so it's not like a film, like what was observed at North Anna Unit 1. The licensee had, in the past, some issues with I believe canoseal leaks from above, had not inspected the top of the head previously, so this was the first --

MEMBER WALLIS: What's this rim of the hat that's at the top there?

MR. HISER: Okay. I think that's related to the insulation, I believe.

MEMBER WALLIS: So how does it get around that and go way back to the nozzle? Presumably, it drips off that cap.

MR. HISER: It may drip between this and the nozzle. Anyway, the significance of this deposit was that this plant has the lowest head temperature upper head temperature at 557 degrees. The EDY is 1.5, so it's very low. It's 67 out of 69 PWRs. The licensee did a UT of the nozzle base material. This was clean. There was no evidence of a leak path, indicating that it was unlikely that the deposit came from the J-groove weld or somewhere in the nozzle.

The J-groove weld itself was PTd by the licensee. The licensee identified it as clean. This was concurred in by NRC Region 3 staff, and our understanding is more recently a third- party independent assessment indicated that the PT was clean.

CHAIRMAN FORD: What does that mean specifically? Somebody else with no --

MR. HISER: Not --

CHAIRMAN FORD: -- conflict of interest?

MR. HISER: Not a licensee member, not an NRC member.

CHAIRMAN FORD: And you don't know who this is.

MR. HISER: Wesdyne, Westinghouse Inspection folks.

CHAIRMAN FORD: Now yesterday -- I mean, the fact is you found some Boron on the head. Do you know unequivocally where it came from?

MR. HISER: My guess is that the licensee may have some explanations of where it came from. Whether they are 100 percent certain is not clear at this point.

CHAIRMAN FORD: The reason I'm being

suspicious, just to be a devil's advocate. We heard yesterday about the inspection techniques. There was all sorts of questions about the sensitivity, the resolution capabilities, and the qualification of the inspector, so to base conclusion exclusively on the UT /PT examination, you automatically feel a little bit uncomfortable about the reliability of that data. It would make a much cleaner story if we knew unequivocally where the Boron came from, that it came from somewhere else.

MEMBER ROSEN: The difficulty, Peter, of course, is that the Cesium Analysis shows it was 5, 10 years ago, when it came from wherever it came from. That was 5 or 10 years ago, so a little bit -- you do a forensic Boric Acid archeology.

CHAIRMAN FORD: Well, again, and recognize I'm being a devil's advocate. I'm being deliberately difficult. How about an original fabrication defect, which then just went through that extra bit, not by this PT/UT, deposited, dropped, and didn't operate very long. There's your 5 to 10 year Boron deposit, but it did crack initially and blocked up. Now I'm giving a hypothesis. Well, I'm asking to be shot down.

MEMBER ROSEN: No one's shooting.

CHAIRMAN FORD: That's what I'm worried about.

MEMBER SHACK: Well, it's hard to be unequivocal, Peter.

MR. HISER: Yeah. I think the kinds of measures we used are --

CHAIRMAN FORD: Where are the sources that the Boron could come from? It could come from inside, and I'm just making a devil's advocate approach, that you haven't shot that one down. Where else would it come from? You're saying seals from above. Is there any evidence that it did come from the seals above?

MR. MATTHEWS: Peter, this is Larry. It's my understanding that 10 years ago they had a major canopy seal weld leak near the center of the vessel at this plant.

CHAIRMAN FORD: And it could have gotten from that position to that --

MR. MATTHEWS: Oh, no doubt about it. The whole head was covered with Boric Acid.

MEMBER ROSEN: And so what that, Larry, says, that they cleaned the whole head, but they left a little bit right here.

MR. MATTHEWS: Or it's easy -- I thought they had Boric Acid everywhere. Now we might need to clarify that, but it's easy also to --

MR. HISER: I think they had a film. They had several discreet locations where they had piles of Boron. This was the only one that was at a nozzle. The others were in-between nozzles. I'm not sure if it was associated with seams in the insulation.

MR. MATTHEWS: It very likely could be, that it could drip through there.

CHAIRMAN FORD: Was that -- when you said it had that drip, was that 5 to 10 years ago?

MR. MATTHEWS: Yes. It was 10 years ago that they had, as I understand it about 10 years ago that they had a canopy seal weld leak, a fairly significant canopy seal weld leak. It's also easy to imagine that the mirror insulation which is just layers of metal, stuff can get in there, and you think you got it all. And then when you start up, it gets blown around.

MEMBER ROSEN: Well, you know, Peter, before we got this information from the Southwest of the United States, I would have said this was a pretty good story. It's a low susceptibility plant. And the arguments about where this came from, and the 10 year old Cesium and that don't hold together very well, in my view. But the fact that it's a low susceptibility plant because the EDY are so low, then I go and say well, probably true. But now that we have this additional information, I'm less certain of that. It shakes the Sequoyah story.

MEMBER KRESS: The Cesium ratio is a pretty good -- that's pretty good evidence.

MEMBER ROSEN: Yeah, it says -- no, that's very good evidence. That says whatever -- whenever the leak happened -- if there's a crack in there, it happened that long ago. And Peter's scenario, you know, there's still a crack there but it's plugged up, it's not now active. But I think this new evidence we're getting shakes the Sequoyah story somewhat, that below EDY plants can, in fact, have cracks based on some other mechanism. The EDY is not the whole story is what this is saying. I mean, we'll see. This is a -- we're in a work-in-progress here.

CHAIRMAN FORD: Is it work-in-progress as far as the NRC is concerned, or is this resolved? Has there been disposition?

MR. HISER: As far as Sequoyah is concerned, I think our understanding is it's resolved.

MEMBER ROSEN: Right. Until they do the next inspection.

MR. HISER: Until they do the next

inspection, which --

CHAIRMAN FORD: They probably won't see anything --

MEMBER ROSEN: Well, but then they'll go back and look at this nozzle, won't they?

MR. HISER: Well, by the orders, by the fact that this has a clean UT, a clean PT, there are no indications it would require any additional inspection. The way that the order is written, this licensee would not have to do even a visual inspection for three refueling outages.

MEMBER ROSEN: Right. But at some point they go back onto the head and look at this nozzle.

MR. HISER: 2007.

MEMBER ROSEN: Okay. That's all I'm saying, is that they --

CHAIRMAN FORD: In all likelihood -- the point is, in all likelihood you won't see anything because if the scenario is right, and according to your Cesium argument, that hey, this is not new Boron, you won't see it any more. It's plugged up. And if there's a question on the UT and the PT.

MEMBER ROSEN: As long as it stays plugged up, that's correct.

MR. HISER: That's true. By 2007, as

well, they would have to do a non-visual.

MEMBER ROSEN: My experience with cracks and plugging thereof is that they don't heal by themselves. They may plug for a while, but the crack is still there. And with enough working and thermal cycles or whatever, vibration, it's not healed. So if the crack is there, it has a tendency to wake up one day and remind you that it's there.

MEMBER WALLIS: If this Boron came from a crack, and apparently it came from somewhere else all together.

MEMBER ROSEN: Yeah.

CHAIRMAN FORD: You've got to prove unequivocally that it came from somewhere else. Larry's got a good point. You know, is it sufficient?

MEMBER KRESS: I don't think you can plug the crack with Boron.

CHAIRMAN SIEBER: I think establishing where -- that it came from someplace else is corroborative of the actual physical examination of the area where flaws might be is the key.

MR. HISER: The one point that was latched onto early- on with this finding was that this head was fabricated at Rotterdam Dock Yards, which I heard a little bit about yesterday. But the PT didn't prove to have any clear indications of the required follow-up. And that's where a lot of the problems were at the North Anna and Surry Units were in the welds.

MEMBER KRESS: Well, if South Texas is determined -- will determine what the source of their leak is, and the root cause, I don't think you have to go back to Sequoyah. I think that will be sufficient to give you enough information to decide whether -- what kind of problem you have.

CHAIRMAN FORD: You mean if South Texas turned out to be a justifiable red herring, then we can resolve this one. If it turns out to be --

MEMBER KRESS: Yeah, that's my feeling.

CHAIRMAN FORD: -- a real crack, then you've got to go back and re-examine it. Is that right? Is that the decision tree?

MEMBER KRESS: No, no. I am thinking -- and base my -- I don't think you're going to find anything about Sequoyah. I think I base my subsequent decisions and processes on what I find out at South Texas.

CHAIRMAN FORD: We're giving you a hard time, Allen. I bet you thought you could get through this in half an hour.

MR. HISER: I thought this was easy.

Before launching into South Texas, which is really focused on the lower head, just to review a little bit. When we issued Bulletin 2002-02 last August, plants in the fall did some inspections of their upper head. We also began to inquire of licensees, of whether they had looked at the lower head at all to see if there were any indications of leakage.

In some cases, licensees found on the outside of the insulation indications of Boron, in some cases rust, things like that. In some cases, what the licensees then did is that they put boroscopes up so that they could get a view of the lower head. No definite signs of leakage were identified. In some cases, the maybe limited follow-up to those indications were attributed to the fact that there's no known history of leakage in this area, so there's -- you know, the licensees didn't feel there was a credible mechanism for leakage for cracks in that area.

With that sort of as a back-drop, there hasn't been a lot of lower head examinations performed. South Texas this spring did what appears to be a very effective lower head inspection. Access at South Texas appears to be very good. Whether that's by design or just a consequence of the design is not clear, but I think South Texas is in probably prime position to do these kinds of inspections.

More recently, I think the Farley plant, if I remember, Larry, was also able to do a very good lower head inspection. That's not the universal case. Access through the insulation tends to be very poor in all honesty, and requires some fairly major disassembly to really get significant access.

Anyway, South Texas identified deposits associated with two nozzles, number 1 and number 46. My understanding is that the upper head was clean at South Texas, so the upper head is good, the lower head is potentially not clean. The EDY of the upper head is somewhere between 4.5 and 6.3. This relates to what temperature assumptions the licensee uses for their operation. I believe in 1999, four years ago, they did a bypass flow conversion.

MEMBER ROSEN: During the steam generator replacement outage.

MR. HISER: Okay. And that was in `99. Okay. And that dropped the upper head temperature from possibly a little over 600 degrees down to about 560, 561. Using a lower head operating temperature of

561, the EDY is approximately 2.1 for the lower head. Before launching into photos --

CHAIRMAN FORD: Now.

MEMBER ROSEN: No, the lower head has always been at 561.

MR. HISER: Right. Yeah, right now in effect the lower head and upper head are at the same temperature.

MEMBER ROSEN: Since `99.

MR. HISER: Right. The licensee from discussions we've had is planning what appears to be a good characterization activity to determine where the flaws are, are they in the base material, the J-groove weld, trying to determine the root cause, whether they're fabrication-related, potentially some sort of flow induced vibration, fatigue. Or is it a PWSEC sort of mechanism, a cranking mechanism. The significance of each of these is different, and what generic responses might be would be different depending on which of these it is.

CHAIRMAN SIEBER: Are you going to tell us how they performed the examination?

MR. HISER: Well, they haven't yet.

CHAIRMAN SIEBER: Tell us how they will perform the examination.

MR. HISER: They don't know yet. We can speculate.

[THE DISCUSSION HAS BEEN REMOVED DUE TO PROPRIETARY INFORMATION]

MR. HISER: Yeah. If we flip to the next page, this is a schematic of what things look like on the lower head. Similar to the upper head, in that there's an inconel buttering, an inconel weld, stainless steel cladding. This is the Alloy 600 penetration itself. As opposed to a four inch outside diameter, this is on the order of one and a half inches. Is that shown there? Yeah, about 1.499 is what's listed there. The wall thickness is on the order of .44 inches, so it's thinner than the upper head nozzles which are about five-eighths.

Penetration number 1 is located here on the lower head, just off of dead center on the bottom head. Nozzle 46 is off on the periphery, so I guess here. The deposits that the licensee identified at Penetration 1, they identified as being gummy in appearance. And we can flip through these every couple of seconds, and I mean they're all the same penetration, just different perspectives. Clearly, you can see the deposit -- the overall head appearance doesn't look too bad. There are areas around nozzle 1 and nozzle 46, in particular. You know, here that have more of a rusty appearance to them. Some of the speculation is that these areas were taped off, and then the rest of the head may have had like an aluminum paint applied to it, but that was not -- they didn't want that up against the nozzles themselves for whatever reason. You can see here the insulation package offset.

MEMBER ROSEN: How big is that dimension between the bottom of the head and the -- it looks huge.

MR. HISER: We're told it's somewhere between a foot and three feet, where the nozzles are located, so this probably is about a foot.

CHAIRMAN SIEBER: That's an inch and a half.

MEMBER ROSEN: Yeah.

CHAIRMAN SIEBER: I expect it's not three feet.

MR. HISER: Yeah. No, it's not three feet, but it --

CHAIRMAN SIEBER: It could be on the side.

MEMBER WALLIS: So what are we seeing here, the bright orange area? What is that, bright red area?

MR. HISER: There is where they tried to highlight for the --

MEMBER WALLIS: Shine the light on there. What's all the white stuff on the ceiling?

MR. HISER: This area?

MEMBER WALLIS: This looks like a parking garage to me. What's on the --

MR. HISER: Yeah, this is probably paint and again, just some reflections from the light.

MEMBER WALLIS: Why is it so spotty?

MR. HISER: Minor surface corrosion.

MEMBER WALLIS: Were these penetrations stress relieved?

MR. HISER: We were told that they were.

MEMBER WALLIS: They were.

MR. HISER: Yes. We were also told that at some point fairly early in life, that there were modifications made away from the head up inside the vessel to this, because of, I believe, vibration problems. They thickened up the --

MEMBER ROSEN: The tubes themselves that go inside were, in fact, thinning in various places because of vibration. And they were removed and replaced with new tubes of a thicker wall thickness so that that stopped the vibration.

CHAIRMAN SIEBER: That was a fairly complex problem.

MR. MATTHEWS: Is that not the dry tubes that go inside of these tubes? Because all of the dry tubes, or a lot of the dry tubes on the Westinghouse plants have had thinning areas, and we've had to monitor that thinning from the idea the dry tube, and reposition those and/or replace those dry tubes. But that's not this Alloy 600 nozzle. It's a stainless steel dry tube that's inside this nozzle.

MEMBER ROSEN: Yeah, that's what I'm talking about.

MR. MATTHEWS: Okay. So it's not this nozzle, it's the dry tube that goes inside this nozzle.

MEMBER ROSEN: Right.

CHAIRMAN FORD: Is there a lot of crud on the bottom of these? Is there crud on the bottom of the pressure vessel?

MR. HISER: I don't think anybody has looked. Presumably, not a lot.

CHAIRMAN FORD: What was the mechanism of thinning of the tube?

MEMBER ROSEN: The mechanism of thinning of the internal tubes, vibration and I think against the -- you know, the inside of the fuel assemblies.

CHAIRMAN FORD: Oh, I see.

MEMBER WALLIS: Now this bright white stuff here is Boron, that bright white stuff. What's the region of corrosion of the low end? It seems --

MR. HISER: There?

MEMBER WALLIS: Right.

MR. HISER: It's not obvious.

MEMBER WALLIS: And there's something -- what's the scar on the tube that runs all the way down it, the top of it there. What's all that stuff?

MR. HISER: It's not clear what that is, whether it's related to fabrication.

MEMBER WALLIS: All that stuff, is that due to -- what is that, scratches, or is it --

MR. HISER: It looks like scratches. The area up here is -- here looks like it has some 3-D character to it. I'm not sure which page you're on, Steve.

MEMBER WALLIS: It looks as if it's been corroded, bigger area than the Boron deposit.

MR. HISER: Maybe if you go to the next page. To me it just looks like there's maybe some surface staining, something like that. Some of the photos it looks like there's a 3-D character to something at the top of the nozzle. But the other one, it looks like it's more just a surface stain or something like that.

MEMBER ROSEN: And here is a very good picture where you see that rectangular pattern on the bottom of the head, that is what you described earlier as they put masking tape around the nozzle and painted the rest of the bottom surface of the vessel with some kind of aluminum paint for some reason. But they didn't do it right up against the nozzle.

MR. HISER: Right.

MEMBER ROSEN: So that's why you see this unpainted area.

MR. HISER: And in all honesty, this one it looks like there's some degree of corrosion going on.

MEMBER WALLIS: Now if these Boron

popcorns grew too big, they'd fall off. Where would they go to?

MR. HISER: The experience on the upper head is that they're very adherent.

MEMBER WALLIS: But here they're on the bottom, so if they broke off, they would fall. On the top they might have less --

MR. HISER: I'm not sure if they would break off. That's --

MR. MATTHEWS: And even if they did break off, they would fall right on the top of these insulation panels here. And I don't believe there is anything there.

MEMBER WALLIS: On this one down there?

MR. HISER: I would expect that that is the first area that they looked was the top of the insulation, because of things like that, that gravity is sort of working against you, keeping things on the head.

MEMBER ROSEN: But this picture, if you look up above it's not so good on the screen directly in front, but up above, it looks very clean, kind of what's been called the dance floor. Is it -- was that a picture that was taken after it was cleaned, or when they first went in? Do you know that?

MR. HISER: I'm not sure which.

MR. MATTHEWS: I don't believe they cleaned anything, except when they were scraping right around to get the samples of the Boric Acid.

MEMBER ROSEN: So that's as-found when they went in.

MR. HISER: Yeah. I think what they said was that the insulation was clean. I mean, there was nothing there, unlike a lot of the upper heads.

CHAIRMAN FORD: A working hypothesis right now is that you've got cracking at this weld here. Is that right? Which might be covered with crud. And that weld is stress relieved. Yes?

MR. HISER: That weld is stress relieved. We're told it was stress relieved.

CHAIRMAN FORD: So the only reason why it would crack unusually would be presumably if a stress relief, but the initial residual stress was much higher than we normally would expect. I mean, that's one hypothesis.

MR. HISER: Right.

CHAIRMAN FORD: Is it not true that small tubes welded into large components generally have a very high residual stress?

MR. MATTHEWS: They will have a high

stress. These are not thin walled tubes. This is a hefty wall on the tube. T-to-D is thicker than the one on top, and so it's --

CHAIRMAN FORD: Thin walled tube. I'm looking for hypotheses, this is cracking. Would it be a --

MR. MATTHEWS: There's all kinds of -- you could have lack of fusion, you could have PWSCC that we don't know why that's going on, you could have a high stress on the ID of the tube that has resulted in a through-wall crack in the tube.

CHAIRMAN FORD: Steve mentioned something about a repair weld. Is that right?

MR. MATTHEWS: No, it was not a weld.

CHAIRMAN FORD: Could you go down on that?

MR. HISER: Yeah. I think it's way up.

CHAIRMAN FORD: Oh, I'm sorry. This way up.

MR. HISER: Well, the --

CHAIRMAN FORD: Okay.

MR. HISER: The head would be somewhere in this area.

MEMBER ROSEN: It's down below that.

MR. HISER: It's down below, yeah.

CHAIRMAN SIEBER: Ahh, there it is.

CHAIRMAN FORD: I thought I heard you say something about some repair, fatigue and repair --

MEMBER ROSEN: No, no. I said something like that.

CHAIRMAN FORD: Well, I'm looking for explanations. Okay. But I'm assuming that the industry is going through that sort of thought process.

MR. MATTHEWS: Absolutely. What possibly could it be, and what are the consequences to the rest of the fleet and programs, and everything else. But we've got to wait until -- we really don't know. All we know now is there's a little Boric Acid residue on the outside of two nozzles. That is the extent of the knowledge until they get in there and do some NDE.

CHAIRMAN FORD: How often is the bottom head inspected?

MR. MATTHEWS: South Texas did a bare metal visual every time as part of their Boric Acid walk-down. Most plants don't.

MR. HISER: They did one apparently six months ago.

MR. MATTHEWS: Yeah, in November they did.

MR. HISER: And did not find anything in this area.

MEMBER ROSEN: In November of 2002?

MR. HISER: Yes.

MR. MATTHEWS: Yes.

MEMBER ROSEN: What was going -- why were they in there in November of 2002?

MR. MATTHEWS: As part of their Leakage Assessment Program, as I recall, any time they have a cold shutdown of a sufficient duration, they go look for Boric Acid. And this is one of the locations that this plant, because of their relatively easy access, includes in their Boric Acid look. That's my understanding.

MEMBER ROSEN: Yeah. That was not a refueling outage.

MR. MATTHEWS: No, no, no. It was just some other cold shutdown.

MEMBER ROSEN: Some other reason.

MR. MATTHEWS: Yeah.

MR. HISER: And my recollection from notes from the licensee was that the other unit they've looked at several times over the last year, and found nothing on the lower head.

MEMBER ROSEN: Unit 2.

MR. HISER: Yes.

MEMBER ROSEN: So six months between

November of 2002 and the spring of 2003, this stuff showed up.

MR. HISER: Right. Cesium dating of this is what I think four years old. But the amount of deposit is very small. I think what I recollect that they said they collected at 46 was on the order of half of an aspirin was the quantity.

MEMBER. ROSEN: But it's four years old, so it's been in -- and they looked six months ago and didn't see it, so the --

MR. HISER: What's here is four years old.

MEMBER ROSEN: Yeah, but they didn't see it six months ago --

MR. HISER: What's up here --

MEMBER ROSEN: -- so it was coming down for four years.

MR. HISER: That's a hypothesis. Yeah, it may be that, you know, like an extruding process, that eventually, you know, gets pushed out. And the Boron that they found started up here four years ago, and just took four years to make the trip to where it was detectible. And what we were told, as well, is that from six months ago, that they specifically know that they saw the area around nozzle 46 because of it's peripheral location. I guess it was easier to get to, so there is some -- they have very high confidence in that time frame, that there was nothing in November, at least on nozzle 46. Nozzle 1 they said -- describe it as a gummy appearance. I think they had some recent history with tape in that area for, I don't remember what the -- some sort of instrumentation or something, and it may have been related to that. But it also had Boron on it, so that was --

MEMBER WALLIS: Now this Cesium dating assumes that the Cesium and the Boron area homogeneously mixed at all times. There isn't sort of a preferential seeping of the Cesium through the Boron in some way?

MR. HISER: It's 134 to 137 --

MEMBER WALLIS: Yeah, but you assume that they move together, and we know that when we look at radioactive stuff moving through the ground, there's all kinds of weird things that happen. Certain isotopes go faster than others because they can attach to the ground in different ways, a very complicated process of tracking radioactive isotopes through porous media. They don't all travel at the same speed.

CHAIRMAN FORD: Okay. Do you think we can add anything more constructive to this debate at this point? Obviously, there's a whole lot of work going on. They're asking all the right questions. Just wait to get the answers?

MR. HISER: And we're trying to get more information. We know that the French have been more -- have done a significant number of non-visual NDEs of the lower head, and we're trying to gather that information. Somebody mentioned about what sort of inspection would you do. Maybe, Steve, if you go back up to that one schematic, the one of the nozzle and the head.

Well, actually, you know, similar NDE to the upper head. What is applied in France is ultrasonic and eddy current into the nozzle ID. Again, it's really restricted to the nozzle base material itself. That would not necessarily cover or find indications in the weld.

MEMBER ROSEN: Why do you show that as coming down from above, rather than up from below? I mean, obviously it would be much easier to come in up from below.

MR. MATTHEWS: No. In fact, it would be almost impossible to come in from below. There's about a 30 or 40 foot tube that's socket welded in right here that goes out to a seal table, and it contains a dry tube. And you have to pull all of that out, and come in -- to even come in from above.

MEMBER ROSEN: But obviously, the importance of this, you could retract that tube --

MR. MATTHEWS: If you retract the tube, you've got water flowing out the bottom of the vessel, unless you freeze plug something somewhere, or plug it from inside the vessel.

MEMBER ROSEN: Yeah, you can retract the tube and freeze plug above --

MR. MATTHEWS: You'd have to freeze plug inside the vessel.

MEMBER ROSEN: Yeah.

MR. MATTHEWS: Or put some kind of plug inside the vessel. Or you could drain the vessel. I mean, there's lots of things to do.

MR. HISER: And that's partly why they don't know what they're going to do yet, because there's a lot of --

MEMBER ROSEN: Trying to think through all that.

CHAIRMAN FORD: Now you say the French have done I was about to say routinely, but they have done far more inspections on this particular sub-assembly than we have.

MR. HISER: Right. Non-visual NDE.

CHAIRMAN FORD: And have you had any indication of -- would they be shocked hearing this?

MR. HISER: I think they are surprised, but clearly not shocked because they're doing inspections. My understanding is their only findings have been one or two fabrication-related flaws.

CHAIRMAN FORD: They haven't found any found any --

MR. HISER: No.

CHAIRMAN FORD: Degradation issues.

MR. HISER: No service-related degradation.

CHAIRMAN FORD: Okay.

CHAIRMAN SIEBER: And you would not expect that here either, would you?

MR. HISER: We would not expect, given our experience with PWSCC of these alloys, we would not expect to see this.

CHAIRMAN FORD: Based solely on temperature.

MR. HISER: Based solely on temperature, whether they're plant-specific. There are fabrication flaws, much as North Anna had.

CHAIRMAN SIEBER: That could be the

answer.

MR. HISER: Yeah. There's a lot of -- the implications are different for every one. Maybe the heat of material is much higher yield strength, I mean, there's a lot of things. How do we know this is necessarily different from every other PWR? I don't know that we know that either. We know that it operates -- actually, the operating temperature of the lower head is actually higher than the upper head at plants like Sequoyah. So this actually -- there's I believe 16 plants whose upper heads are colder than South Texas' lower head, so maybe that does fit within the --

MEMBER SHACK: That doesn't seem to jive with your 2.1 years though.

MR. HISER: Well, the operating time here is pretty low. And if you look at Bill Cullen's plot from yesterday, there's about 15 or so plants that are down in a very low EDY area. This would fit in at the upper bound of those, if it operated for a long enough time period to accumulate the EDY.

CHAIRMAN FORD: Okay.

MR. HISER: So if this were the upper head and you had full access like Sequoyah did, you would want to do NDE of the ID of the nozzle. If you found nothing, you'd want to look at the weld to see if that's where the leakage path is. You know, we know that there are people in the world who have done NDE of the ID of the nozzle. Nobody that we're aware of has done anything on the J-groove welds. Again, it's a smaller diameter. The geometric sorts of concerns with the relatively high hillside, I mean, all of those become more pertinent here, more restrictive.

MEMBER ROSEN: This is an exaggeration, isn't it? I mean, the vessel head is not -- according to these pictures, it's not that steep at that point.

MR. HISER: Yeah, it's pretty steep on the outer row.

MEMBER ROSEN: Well, open for 46 which is one of the outer ones, it probably is.

MR. HISER: Yeah.

MEMBER ROSEN: Number 1 is right in the middle. It's flat.

MR. HISER: It's just off a little bit, but yeah.

MEMBER ROSEN: It's nearly flat.

MR. HISER: Absolutely. I think on some of the -- on the upper heads some of the angles we've seen are on the order of almost 45 degrees on some of these.

MEMBER ROSEN: And it might go to 46.

MR. HISER: Yeah.

MEMBER ROSEN: For one, the one that's of principal interest right now.

MR. HISER: Well, one is the one that had what they called a gummy appearance to it.

MEMBER ROSEN: Oh, okay. I got it backwards.

MR. HISER: Yeah.

MEMBER ROSEN: 46.

MR. HISER: Yeah.

CHAIRMAN FORD: Okay.

MR. HISER: Okay. Where are we going overall? That's just to summarize on this page, and then the next page with some ideas on interactions with the industry. Clearly, what we want to do is get to a point of permanent requirements. We want to get out of order space, bulletin space. Let's get something in the ASME Code, get something in 54.55a. The ASME Code is working on this. For anybody that's familiar with the code, it's glacial is about the pace that it works at.

Right now the ASME Code work has been based on the industry report, MRP-75. We have provided some comments to the MRP. To be real blunt, we did not think that the report was acceptable last summer, last August when we first got it. And as the industry works to revise it, clearly acceptability of the final product is not certain. I think there may be some philosophical differences that we have had with the industry. Hopefully, you know, we'll both be able to get on the same page overall with what is acceptable.

As we talked about, we did suspend review of the report pending revisions by the industry, which I guess we're expecting by the end of the summer. At this point, it's not clear that ASME Code adoption would be complete until 2004 or later. Things like South Texas helped to delay that, you know, just creates more doubts in our understanding of what's going on.

One thing we do know is requirements will be implemented in 50.55a. Hopefully, we'll be able to endorse what the ASME Code develops under some sort of an expedited implementation process that relates to getting 50.55a updated, and then having licensees pick up that code addition, so we would probably want to expedite implementation so that the requirements become effective pretty much immediately.

If that does not work out, if the ASME

Code does not develop acceptable requirements, then we will codify some alternative inspection requirements. Know clearly at this point what that would look like, and we have the order on the books right now. Presumably, that's our best thinking at this point in time. However this works out, once we start to revise 50.55a, it still will take a time period for these requirements to be implemented, so that's --

CHAIRMAN FORD: From a control aspect, regulatory control aspect, do we take it in the remarks of Rich Barrett to be the first date, that the order that you have out right now will be sufficient to maintain safety aspects for that sort of time period, out until one to two years? They are all-encompassing enough to take into account potential cracking, such as maybe at South Texas? Sufficient to take into any potential Boric Acid corrosion effects?

MR. HISER: Yeah.

CHAIRMAN FORD: And then as we get out to one to two years, and we've sorted out this MRP, the industry life management approach that they're putting forward, supplemented by the one that was described yesterday by Bill Cullen, then you can come in two years time, come into a modified version of the regulations? I'm trying to get an idea of -- you're talking several times here before we going to get any changes to the current situation.

MR. HISER: I would expect that once we fix on what inspection requirements are necessary, that we would probably, if that's different from what's in the order, we would probably revise the order while the ASME Code and while 50.55a are being revised, so that we would have some continuity at that point.

CHAIRMAN FORD: So the order would become more stringent.

MR. HISER: Well, I wouldn't say that. I would say the order may be different. It may be less stringent in some areas. It may be more stringent in other areas, given what we've seen at Sequoyah and South Texas. If those were to pan out to indicate that there may be more susceptibility with what we thought were low susceptibility plants, that part of the requirements would probably get beefed up. They'd become more stringent.

There are some folks that think that the high susceptibility plant requiring non-visual NDE every outage is too stringent. I mean, so there may be -- it may be that right now we have too steep of a curve between high susceptibility and low susceptibility, and that needs to flatten out somewhat. But, you know, that's just -- that's trying to pre-judge what we're going to have happen. We may be here in six months, and Plant XYZ had some other unique findings. Or maybe the industry will look at the North Anna head and find something totally unanticipated. But I think right now, I think we're fairly well-positioned for the interim.

In terms of interactions that we have ongoing with the industry and I think this has been provided to NEI separately, clearly revising and updating MRP-75 is a high priority. We have had good interactions with the industry, and that sort of is diminished with Davis-Besse and, you know, sort of fighting fire after fire in order for MRP-75 to be in a real -- in a position that we're real comfortable with, and I think we need to renew the staff level interactions.

Tom Alley talked yesterday about the inspection tools. Clearly, there's room to improve those, and I think the industry is looking a lot in terms of delivery and efficiency of the inspections. Effectiveness is also an area that needs to improve. The industry has activities to characterize heads removed from service. We've heard about North Anna

Unit 2. Hopefully, some of that can be extended to other heads. Boric Acid corrosion research that they talked about is -- it looks like it's addressing the correct issues.

The one area that we -- that really before vessel heads, we had VC Summer with the butt weld cracking issue. That sort of -- you know, we dealt with that for a little bit two years ago, and that really has been put on the back burner. And I know that the ACRS members expressed a lot of interest in that yesterday. And I think that's an interaction that we're going to renew with the industry, is to have them finalize their report that they provided to us two years ago, so that we can start to move forward in some of these other areas, instead of being bogged down.

MEMBER WALLIS: I remember at that incident there was a huge Boron stalactite. It was a huge amount of Boron that came out before anything was detected. It was quite surprising, not only that this happened at all, but there was so much Boron deposited from that leak in VC Summer.

MR. HISER: But see, that may have provided some false reassurance that you're going to get tons of Boron. I think that was the expectation six years ago. You know, now clearly we know differently. You know, a gallon per year from Oconee Unit 3, 180 degree cir crack. That's the benchmark. Ten to the minus six GPM. That's not much water coming out. That's all I have, Mr. Chairman.

CHAIRMAN FORD: Are there any other questions from the members?

MEMBER WALLIS: Well, I guess that one of the weak points here is Bullet 2, how good are these underlying analyses? Apparently, they're not satisfactory yet, and I don't know this Committee has any measure of how likely they are to be satisfactory at some future date. Isn't that one of the key things that's holding up progress, is getting some very solid underlying analyses to support MRP-75?

MR. HISER: I think understanding what's going on is really one of the keys, as well.

MEMBER WALLIS: Well, what's the prospect of getting that in a reasonably short time?

MR. HISER: Well, we were told yesterday August.

MEMBER WALLIS: Yeah, but that seemed to be unreasonable.

MR. HISER: Well, I guess -- I think from the NRC perspective, we're comfortable for the interim where the order puts us, unless South Texas, Sequoyah sorts of findings indicate that we need to modify our position. We're comfortable with where the order puts us. The industry probably wants some relaxation, generic relaxation of the -- again, much as with the Alloy 690 heads, the burden is on the industry to provide the basis that would enable us to change our position.

CHAIRMAN SIEBER: It seems to me if you look into the future and speculate as to where you're going to go, South Texas has two impacts, in my view. One of them is, it opens for inspection a whole new area which has doubled now the work of this inspecting the upper head. The second thing is, it seems to me that you can take your susceptibility curve and throw it away.

MR. HISER: The difference in geometry, in fabrication and all, it may be that there's different susceptibilities.

CHAIRMAN SIEBER: It could be.

MR. HISER: I think there was some mention of small diameter nozzles on the upper head. Two B&W plants had I think about one inch diameter therma couple nozzles, eight at each plant. One plant, all eight were cracked. The other plant, they had five out of eight that were cracked. You know, the prevalence of cracking there was much higher than the CRDM nozzles at those same plants. It may be that there's just -- you know, that the conditions are different. It may be the EDY is okay, but we just need to shift the cut-offs to lower values for the lower head, as an example.

CHAIRMAN SIEBER: That's true, but it's obviously an area where continued thought needs --

MR. HISER: Absolutely. You know, we have no preconceived notions at this point.

MEMBER ROSEN: At some point when you shift the EDY to lower numbers, you're basically saying everybody is old enough to be --

MR. HISER: Well, but it may be that what you see on the lower head may not necessarily relate to what you're going to see on the upper head. And that's the only -- one thing -- I focused on all the negative things from the last couple of outages. There are some plants that are very high susceptibility, that I think Larry may have mentioned, Bill Cullen mentioned. They did full-blown inspections, visual, UT and in some cases EDY current. They found no cracks anywhere. These are top five plants. There's something going on. There are good news stories out there.

CHAIRMAN FORD: Okay. I'd like to recess for one hour for lunch, and then we'll return at 1:00 for the final presentation, so we're in recess.

(Whereupon, the proceeding in the above-entitled matter went off the record at 11:54:09 a.m. and went back on the record at 1:01:18 p.m.)

CHAIRMAN FORD: Okay. I'd like to get back into session. The last presentation we have for this Subcommittee Meeting is addressing the Plans for Addressing the Davis-Besse Lessons Learned Task Force Recommendation, Brendan Moroney, and Cayetano Santos. And apparently, they're going to do a tag-team act on this subject.

MEMBER WALLIS: Is this something I have?

MR. MORONEY: You should. It's got big black letters.

CHAIRMAN SIEBER: It should be wet.

MEMBER WALLIS: Okay. It's underneath. It's the last one.

MR. MORONEY: Good afternoon, gentlemen. We're here to give you a briefing on the action plan for addressing the Davis- Besse Lessons Learned Task Force.

COURT REPORTER: Excuse me. Would you

pull the microphone closer.

MR. MORONEY: Good afternoon, again. My name is Brendan Moroney. I'm with NRR, Division of Licensing Project Management, and I have Cayetano Santos who's in Research, Division of Engineering. And we're here to give you a briefing and overview of the action plans for accomplishing the Davis- Besse Lessons Learned Task Force recommendations.

As a brief overview of what we're doing today, the plan involves an overall implementing plan for addressing the actions and the recommendations. We'll describe what the overall plan is. And then the overall plan does include specific action plans in specific areas, and we'll briefly tell you what all of them are, but our intent today is just to discuss two of them, one in the stress corrosion cracking area, and the other one in the barrier integrity requirements area.

By way of introduction, I'm sure you're all familiar with the LLTF report, which came out in September. The EDO referred it to a Senior Management Review Team, which reviewed the recommendations and then made its own assessment and recommendation to the EDO at the end of November. There were originally 51 recommendations. The Senior Management Review Team deleted two of them that they thought were not necessary to be accomplished or appropriate to be accomplished, leaving 49 recommendations. They took those 49 recommendations and divided them up into four general categories, and then assigned priorities to each of them, either high, medium or low.

MEMBER ROSEN: Do you have them by category or by individual item?

MR. MORONEY: Each individual item was given a -- within a category was given a prioritization. The EDO then issued a tasking memorandum on January 3rd of this year to the Directors of NRR and the Director of Research to jointly develop a plan for implementing the recommendations. Together we developed an overall implementing plan which was delivered to the EDO on the 28th of February, as required. This plan was subsequently forwarded by the EDO to the Commission for their information on March 10th, and we're operating now under the provisions of those plans to accomplish the recommendations.

The overall plan consists of three parts, actually. Part is to address the high priority items of the 49 recommendations, and there were 21 of those that were listed or given a high priority by the review team. And there were four action plans developed, and they were structured along the lines of the categories that the review team had put them in. And what they are is addressing stress corrosion cracking issues which NRR/DLPM has the lead on for plan management, but the technical part of that, you've heard from the people that are really doing the in the trenches work on that, which was Allen Hiser, Bill Cullen, people like that over the last couple of days.

There's a plan for operating experience assessment. The lead on that is the operating experience branch, NRR/Division of Regulatory Improvement Programs. And I was told also that there will be a specific presentation on that particular evolution at your May 8th Full Committee Meeting.

The third area had to do with inspection program, assessment, project management, and that has been assigned to our Division of Inspection Program Management. And finally, there was one on barrier integrity requirements, which the lead on that is Research.

The remaining items in the low and medium priority categorization were to be addressed through the agency planning, budgeting and project management process, the PBPM process, which is a process by which the leadership team, the executives of each office sit down and prioritize, schedule, assign responsibility for various work that has to be done within their groups. And those items in the overall plan we committed to having the initial screening completed by August of this year, so the other 28 items that are low and medium priority will be addressed through the PBPM process by August of this year.

In fact, we have an initial presentation scheduled for our leadership team on May 20th, to start presenting to them what has to be done, and our estimates of the potential schedule, resource requirements, and so on.

The third aspect of the plan was to provide for tracking and reporting of the items. And action plan items, the actions plans were developed in accordance with our office instruction on action plan management. And we have quarterly updates to the Division Director level of the status of all action plan items, so each of the high priority items will be statused and updated at least on a quarterly basis to our Director, our Division level.

The EDO's tasking memo and the recommendations from the review team was that all the items should be updated and statused at least on a semi-annual basis, so we also have in the plan put a provision for making a semi-annual report on all items and their current status. And the first report is due six months after the date that we implemented the plan, which was February 28th, so at the end of August, we will have our first semi-annual report. So that's basically the overall plan as to how we are structuring this for accomplishing the recommendations. Are there any questions so far, before we go into some of the specifics of the plans?

Okay. We're going to talk in more detail today about two of the action plans. The first one is the stress corrosion cracking concerns, and the other one is the barrier integrity concerns. The SCC Action Plan has three major parts. The first has to do with development of the reactor pressure vessel head inspection requirements. The second part has to --

CHAIRMAN FORD: Is this related just to the reactor pressure vessel head? How about pressurizers penetrations, how about bottom head penetrations?

MR. MORONEY: Right now it's focused on the pressure vessel head. It presents the -- that was the area of focus in the recommendations, and the concern that came out of the Davis- Besse. However, it has provision for expanding into other areas, as necessary. In particular, I think when we look at the Boric Acid corrosion program and inspection requirements, looking at that, that will branch out into a lot of different areas, all nozzles and penetrations, lower head and things like that.

CHAIRMAN FORD: What will trigger such an extension of the scope?

MR. MORONEY: Well, a review of the experience and the information that comes in, plus the inspection requirements that are proposed, you know, by the industry and our review of those.

CHAIRMAN FORD: So essentially, it is reactive. You will wait until something goes off in the middle of the night, and then you will react to that, alter you program accordingly?

MR. MORONEY: Well, we'll certainly be responsive to any issues that arise. I mean, you know, the program has an active and a reactive phase to it. I mean, we are certainly looking at for inspection requirements, we're monitoring and in some ways, you know, following along with the industry by our review of the MRP documents, and ASME Code developments, things like that. And, you know, one of the action items in the recommendations of the task force was to participate in that, and to encourage those things to be moved along to the way we want to do things. But in addition to that, we have a lot of research effort going on, and a lot of our own internal reviews to decide, you know, how we want to go, and where we think the inspection programs ought to be, and what the scope ought to be. And those are kind of moving in parallel.

I think the staff is deferring somewhat to the industry to see -- to allow them to try and develop something that they can present, can be put into the ASME Code, and then we could endorse that, if it's acceptable. But in the meantime, we are proceeding along doing our own reviews and our own evaluations. And at some point in time, it's possible that if the industry efforts are bogged down or not proceeding at a satisfactory pace, we will go ahead and take the lead on establishing --

CHAIRMAN FORD: I'm just curious because Alex Marion indicated yesterday that it was trying to take more of a holistic view of the degradation of the whole -- in this case of the primary waterside PWRs, which would include not only pressure vessel top head, bottom head, and also pressurizers, where we know we've had problems. I'm just curious as to why we at NRC are holding back on doing such more proactive work, and letting the industry dictate - that's the wrong word - show the way of how it should be done.

MR. MORONEY: Well, once again, I guess I'm not sure that it would be categorized that we're sitting back and letting them take the lead. I think it's a parallel effort right now. We're certainly working with them and, you know, following what they're doing, and willing to accept their input and knowing that there is a process where it will develop recommendations and the code committees will, you know, try and factor those into updates for the code. And then we will ultimately make those, you know, part of our own regulations. But we certainly have the ability to proceed ahead on our own rule making if we figure that's the appropriate way to go.

The second part has to do with -- it's a similar type of an effort, but having to do with Boric Acid corrosion control activities, inspection requirements and the scope of inspections, and potential changes in regulatory structure there. And third would have to do with inspection program improvements, which would be a fall-out from any changes that do arise from the changes in our inspection requirements or regulations.

Going into a little more detail, in the Part One as far as the SCC inspection requirements, or the reactor pressure vessel inspection requirements, there's an effort underway, a project underway now to collect worldwide information and establish a data base on experience in corrosion and cracking. I think Bill Cullen gave you some information on that yesterday. He sort of has the lead on that from Research, and that is ongoing, and expected to be complete a year from now.

CHAIRMAN FORD: Now is that worldwide information on data or is it on experience, operating experience? I'm assuming the former. Is that correct?

MR. MORONEY: Well, I think it's both. I mean, operating experience information that comes out of the reports from around the world, whatever format it's in, it's still --

MEMBER ROSEN: Now the distinction in Peter's question that I'm interested in is, is it data on research on stress corrosion cracking, or is it data on operating experience with plants that operate material susceptible to stress corrosion?

MR. MORONEY: Oh, I see. My understand is it's the latter.

CHAIRMAN FORD: Operating experience.

MEMBER ROSEN: Operating experience of plants that use materials susceptible to stress corrosion cracking.

MR. MORONEY: Right.

CHAIRMAN FORD: Because, Bill, in his presentation yesterday talked primarily about data, not operating experience.

MEMBER ROSEN: You mean data, research data.

MR. MORONEY: Well, I'm sure there's a lot of that involved but, you know, I think that the latter part is important.

MR. HISER: Yeah. I think actually it is both. As you're aware, MRP has collected data from around the world, and I think the interest is to continue to collect the experimental and crack growth data, and similar kinds of information, along with the operational experience.

CHAIRMAN FORD: That's important. It's very easy to crack 182 in the lab, not so easy to crack it in the --

MR. HISER: Yeah.

CHAIRMAN FORD: These are PWRs.

MR. MORONEY: Yeah, I think the focus of the LLTF recommendation was to actually get operating experience.

MEMBER ROSEN: But you're doing both. You're going beyond the original intended focus.

MR. MORONEY: That's true.

MEMBER ROSEN: Okay. That's a good thing.

MR. MORONEY: Good.

MEMBER ROSEN: Used your brain.

MR. MORONEY: There's another step which would be to evaluate the SCC models for use in the susceptibility index to determine, you know, their continued applicability and effectiveness. I think Bill also talked a lot about that yesterday.

MEMBER ROSEN: You're talking here about, for instance, the time and temperature.

MR. MORONEY: Uh-huh.

CHAIRMAN FORD: And when you say models, you mean the empirical models.

MR. MORONEY: I think so.

CHAIRMAN FORD: Not anything deeper than that.

MR. MORONEY: I think so. Then we're doing an evaluation of the results of all the inspections as they're completed. We get the reports from each of the plants of the inspections that are done in response to the bulletins and the order, and that's an ongoing process right now. The way the schedule is laid out for the various refueling outages and inspections, it would be in the spring outage season of next year before all of the plants will have been through at least one of the cycles where they've had all of these inspections, so we anticipate that at least the first go-around of the complete results of inspections would be completed by around May of next year.

The other part we talked about before is, we're also evaluating the MRP and ASME efforts and, you know, following them very closely in our review of those items.

CHAIRMAN FORD: We know what the MRP -- we've had several presentations on the MRP efforts. Can you tell me something more about the ASME effort?

MR. MORONEY: Well, the ASME Code Committee will be revising their, you know, Section 11 inspection requirements primarily based on the input that they get from the MRP, as I understand it. That is probably not going to take place for quite a while. The MRP has, you know, they had originally submitted their first edition of the MRP-75, and then that was withdrawn, and I believe I heard yesterday that they're gearing towards having it revised, or a new edition of that in this summer sometime, so it will be, you know, over the next or so that we'll be following that. And I'm sure there'll be a lot of discussions, meetings, and activities as part of that review.

I think the ASME Code updates probably will not take place, or not occur until the latter part of next year at the earliest. And then it would be our position at that point to either accept or, you know, propose even alternate ones. If we accept it, you know, it would be incorporated into our 10 CFR 50.55a, and if we have to go ahead with additional or different recommendations on our volition, then it would be part of additional rule making activity which could go on for an extensive period of time, so it might be a couple of years before that would be accomplished.

CHAIRMAN FORD: I realize that this is a high priority item.

MR. MORONEY: Uh-huh.

CHAIRMAN FORD: And therefore, we'll have the resources to make it a high priority.

MR. MORONEY: Yes. All of the items that

-- our leadership teams have already been briefed or presented all of these items. They agreed to them, and part of the action plans were estimates of resource requirements and costs, and those have all been approved.

CHAIRMAN FORD: But the time limits of this, you mentioned that you would probably get to the end of this page by the end of 2004.

MR. MORONEY: Right.

CHAIRMAN FORD: But many of the inputs are out of your control.

MR. MORONEY: That's true.

CHAIRMAN FORD: Worldwide information, the ASME efforts, the MRP efforts, so is this a realistic figure?

MR. MORONEY: I think it's as realistic as we can give it right now. I think the collection of information, you know, will be complete. It will be as up-to-date as it can be in a year from now. Obviously, that's just the start of the database and then it will continue after that, you know. It will be kept as an active thing.

CHAIRMAN FORD: The reason why I'm asking the question is not to be argumentative, but to give us a feeling as to how long we're going to be in limbo.

MR. MORONEY: I understand. Yeah. And we are, to a certain extent right now because of the delays in some of the MRP submittals. That looks like it's finally starting to move ahead again, and I think the best that anybody can judge right now is that, you know, it won't be until late next year that we have any real firm path established. And really the fifth bullet there is really the final culmination of that. You know, once we have that, we'll codify it in our regulations.

Part two of our action plan has to do with the Boric Acid corrosion control programs. And once again, it starts out with a collection of worldwide information, operating experience on Boric Acid corrosion. This is an effort similar to the other one, but it's a little bit behind. It probably won't be completing this until the latter part of next year, probably around October of next year is our target for right now.

Ongoing at the present time and continuing will be the evaluation of the responses we get to the Bulletin 02-01, which the licensees will all have provided the information on their Boric Acid corrosion control programs.

The initial review, all of those initial responses are now in. They have been under review. The initial review and a summary report of the findings and the evaluation of those is due by the end of this month. That is in draft format right now, being prepared for, you know, sending to management concurrence. So by the end --

CHAIRMAN FORD: I'm sorry to interrupt. This information here you're evaluating right now, what sort of format is it, corrosion rates and alloy steel and Boric Acid at various temperatures?

MR. MORONEY: No, it's inspection program requirements, what they're looking for, how they address where they find evidence of Boric Acid corrosion or leakage, what the scope of components or parts of the primary system that they look at.

CHAIRMAN FORD: So it's more of an engineering observation rather than scientific data.

MR. MORONEY: Yes. Right. As far as the evaluation of the licensee programs, yes. Based on our review of those responses that we receive, and our evaluation of the programs, there will be a decision whether or not currently established programs are adequate to achieve, you know, a real good program for finding and dealing with Boric Acid leaks. So once that report is compiled and put together for management review, there will be a decision as to whether additional regulatory requirements, for example, an extension of the bulletins or orders in the near term might have to go out asking for additional inspection requirements.

CHAIRMAN FORD: Surely there's a big jump between items 2 and 3. Items 2, as you said, just collecting a whole lot of engineering observations and data from operating plants. It doesn't tell you why you have got that degree of degradation in specific plants. Fortunately, very few instances of degradation, so you've got --

MR. MORONEY: Well, I'm not sure --

CHAIRMAN FORD: -- a very simple database to make any evaluation of the need for additional regulatory actions.

MR. MORONEY: Well, I think the additional regulatory actions would be whether or not we think that the programmatic approaches to inspecting and dealing with leakage of Boric Acid containing systems is adequate.

MEMBER ROSEN: Well, let me take a for-instance here. I think it says April, 2003 is the target completion date for that activity in your summary.

MR. MORONEY: Uh-huh.

MEMBER ROSEN: That's now. Okay?

MR. MORONEY: Yes.

MEMBER ROSEN: And what I would presume you're doing under that plan is looking at all these licensee programs and saying well, gee, here's a program or two, or five, or however many that doesn't ever inspect the lower head.

MR. MORONEY: Uh-huh.

MEMBER ROSEN: And now we know that that's probably a good thing to do. And that's what you'd be going back with probably, I'm presuming, and saying to those licensees, you know, there are some things you really ought to do in addition to what you propose.

MR. MORONEY: Right. There's probably a couple of aspects we might do. We might put out something that would say, like an RIS, Regulatory Information Summary, that would say here are some of the best practices that we have found. But, you know, that's just informational. All right. And in order to give it some teeth, we really think that there's not enough being done in some of the areas, and we want more done right now and on a continuing basis, that we'll have to follow it up with something that has more teeth to it, like an order, additional bulletin or something like that.

And then ultimately, the long-term approach would be similar to with the ISI program, would be to incorporate it into the 50.55a requirements and the regulations as to what the final inspection requirements should be, which is the next step there basically. And that, once again, is not anticipated until late `04 or early `05, that the current work by the ASME Committee would complete their current plans or recommendations.

MEMBER ROSEN: Well, I'm making a presumption here that if you decide that certain plants need to do more, you don't have to wait until the code is revised.

MR. MORONEY: No, that's correct. That's the reason for determining if any immediate or near-term additional regulatory action is required. The ultimate goal, instead of having bulletins and orders, would be to have it all codified.

CHAIRMAN SIEBER: I guess if I step back and look at what you folks are doing, you're basically responding and coming up with a potential for the need of additional regulatory action based on the information you're getting from the plants.

MR. MORONEY: Yeah, we'll have --

CHAIRMAN SIEBER: On the other hand, that won't take care of the surprises. For example, some of the surprises have been the fact that Boric Acid can dissolve into the base metal of the head.

MR. MORONEY: Uh-huh.

CHAIRMAN SIEBER: Another surprise is that potential leak, because I don't know that there's a leak yet, in an area that's relatively cold. And, therefore, low degradation years which now in my mind calls into question the value of the ranking system that you have. And there's -- what kind of effort are you making to try and brainstorm where all the surprises might be, and how to roll those into a monitoring program, or an inspection program that will give you a clue before it turns into a big deal?

MR. MORONEY: Well, I think some of that is coming right now. The people that were reviewing all these responses, you know, the technical staff had set down some parameters, you know, a model template for what they expected to find in a program, and are reviewing the responses according to that.

Some of the things that, you know, we're looking at potentially to try and maybe get away from some of the surprises is the fact that people hadn't been looking at the lower head, or people had not been removing insulation in order to inspect various parts of the piping, or the components, or nozzles, or things like that.

CHAIRMAN SIEBER: And they're not required to.

MR. MORONEY: They're not required to right now. And potentially, one of the actions coming out of this review and the analysis of what is being done, versus what we think is probably more appropriately done, would be to provide new requirements, and that's where we're heading. So that's where, I think, the only way right now we can potentially look at, if you have better coverage, better inspection access requirements, you're more likely to find something in an incipient, you know, nature than you would have waiting for it to come and bite you.

CHAIRMAN SIEBER: Well, my concern is one as to whether the agency is reactive or proactive. Right now the way it would appear is that when surprises occur, the agency becomes reactive, which means the effective condition has an opportunity to develop where it might become an initiator, before there's a regulation to control what is going on. And so it would seem to me that you ought to be looking at these anomalies with a fair amount of scrupulosity to see whether you're covering all the bases or not, as opposed to perfecting the inspection of upper head nozzles or, you know, making sure that all the Is and all the Ts are dotted, and developing to the great extent the framework of plans, inspection procedures and data collection we have right now. And I think that helps the agency move to a point where its sort of a step ahead of the game, instead of a step behind.

MR. MORONEY: Right. I agree and, you know, obviously some things are reactive because of events that have happened.

CHAIRMAN SIEBER: They're surprises.

MR. MORONEY: And, you know, we're trying to now step back or, you know, move ahead and say okay, you know, we got surprised. Let's react to that and see what we can do to be better in the future. And I think there's -- you know, the inspection requirements like for looking for leaks of Boric Acid and how you handle them, I think there's some synergy between that and the research efforts that are going on on, you know, what are the susceptible areas for leakage and so on. And they'll be -- those people will be working together. And anything that comes out of one, that effort will certainly be fed into the other part of the program so that, you know, if our research on susceptibility and potential areas of leakage show that there ought to be better inspections on that area, that will be factored into the inspection requirements.

CHAIRMAN SIEBER: Well, please tell me if I'm incorrect in my perception of what's going on, because you may -- you, obviously, know your own programs better than I do.

MR. MORONEY: Uh-huh.

CHAIRMAN SIEBER: But that's the impression I have right now, and I'm encouraging you to be --

MR. MORONEY: More proactive.

CHAIRMAN SIEBER: Move so that you have a larger view of what's going on. But if I'm wrong, tell me.

MR. MORONEY: No. I don't think you're wrong. I'm not challenging that. I just --

CHAIRMAN SIEBER: Well, I want to make sure that I'm right by giving you the opportunity to --

MEMBER ROSEN: Well, let me encourage you along Jack's lines also in another area, which I served up a slow high curve ball this morning expecting it to be hit out of the park, and actually it fouled off, so I'll throw up another one.

What we find -- what's happened at least twice that I know of, is licensees having unexpected conditions discovered.

MR. MORONEY: Uh-huh.

MEMBER ROSEN: And then destroying the evidence of those unexpected conditions by a repair before anybody could really say oh gosh, here's something very important. Let's carefully take it apart.

CHAIRMAN SIEBER: For understanding.

MEMBER ROSEN: And understand it, and feed it into our regulatory process, for one thing, but also into the whole engineering/scientific database so that we can evaluate it. And so the slow pitch is, can you put in a regulatory requirement that effectively quarantines such cases so that the industry and the regulatory system could learn the lessons that are learned before they're put back in service, in a way that destroys the evidence?

MR. MORONEY: I think we probably can.

MEMBER ROSEN: At least it's a fair ball.

MR. MORONEY: No. I can't see why we

couldn't, you know, work that into the rule somehow or other.

CHAIRMAN SIEBER: Yeah. On the other hand, you have to do that with great care.

MR. MORONEY: Absolutely.

CHAIRMAN SIEBER: Because you're basically forcing the plant to remain shutdown in order to quarantine and preserve the evidence. And the industry, whether we like it or not, this is a --

MEMBER ROSEN: This is a business.

CHAIRMAN SIEBER: This is a capitalist society, and they can't stay shutdown very long and still survive.

MEMBER ROSEN: But there's a balance.

MR. MORONEY: Yeah.

MEMBER ROSEN: That's what I'm saying is we need -- and the right answer to the fair ball, as far as I'm concerned, even a base hit is for the industry and the staff to jointly work out a way to meet both objectives. Recognize it's a business, but recognize that business is better served by understanding these phenomenon, and that that may take a bit longer than it takes to simply grind out the crack, re-weld it and get back in service.

CHAIRMAN SIEBER: Well, if it hadn't been at Davis- Besse the fact that they were attempting a repair in the mechanism, you'd be putting it back together --

MR. MORONEY: May not have found it. Right. I mean, you know, part of the principles, I think, of a good corrective action program is to properly understand what the condition was when you started.

MEMBER ROSEN: Root cause.

MR. MORONEY: Root cause. And, you know, my experience has been that, you know, you do your best to at least identify and preserve the evidence that you have initially, and then work from there. You know, that doesn't mean you quarantine the thing and say you don't start up for a month so that, you know, every scientist or whatever could come in and review a leak, but you at least, you know, preserve enough of the initial evidence, and take pictures or, you know, whatever you do, videotapes and --

MEMBER ROSEN: Ultrasonic examination.

MR. MORONEY: Yeah, things like that. And I don't think that's extensive --

MEMBER ROSEN: No, I think you've answered the question correctly. I think it's the correct answer, and you've also indicated the regulatory hook you already have to do so, which is Appendix B to 10 CFR 50.

MR. MORONEY: Right.

MEMBER ROSEN: It requires you to take corrective action. Corrective action always includes determining root cause.

MR. MORONEY: Uh-huh.

MEMBER ROSEN: I mean, any good corrective action.

MR. MORONEY: That's right.

MEMBER ROSEN: Or at least the apparent cause, you know, something other than just remedial action, which fixes the thing. Broke pump/fix pump.

MR. MORONEY: Uh-huh.

MEMBER ROSEN: That's the standard one. WE don't know why it broke, but we fixed it.

CHAIRMAN SIEBER: Well, we've had enough philosophy.

MR. MORONEY: The third phase of this action plan has to do with inspection program guidance that we give to our inspectors, or our people that go out and evaluate plant programs, and activities. And there's three areas or recommendation that we're going to address there.

The guidance for the periodic review of

the licensee ISI activities, this is inspectors actually going out, observing during outages what kind of activities are going on, how the inspections are progressing, and actually taking a look at some of the things independently on their own.

Second would be to provide guidance for timely periodic inspections of the plant Boric Acid Corrosion Probe Programs. One of the problems that are potential contributors to the Davis- Besse event was the fact that there had been some follow-up planned inspections of Boric Acid Corrosion Control as a result of the Generic Letter 88-05, and some other activities. It got deferred, displaced by the new ROP Program, so there were a couple of potential missed opportunities there, and they went for several years. I forget the exact number, without having any kind of inspection by the NRC, any detailed inspection of their programs. So part of this would be to, you know, establish guidelines that would set some minimum standards for how often and how -- what scope of inspection should be doing on Boric Acid Control Programs.

And then the corollary to that would be to provide guidance to the inspectors as to what to look for when they go out and inspect the programs, so that they can make judgments as to how well the programs are accomplishing their objectives, whether they're adequate to properly identify and take corrective action on leakage, things like that.

CHAIRMAN FORD: Brendan, we heard yesterday and a little bit today some information on this topic of inspection techniques, periodicities and I must admit, I personally had some heartburn because maybe I didn't understand the process. From what I understood, for the cracking situation, the NRC does not qualify inspection techniques, quantitate, qualify inspection techniques, nor do they qualify inspectors. Would you tell me if I'm correct or incorrect on that statement?

MR. MORONEY: If that's what you were told, I have to assume it was correct. I'm out of my element there. I'm not an inspector.

CHAIRMAN FORD: So when you say you have inspectors who go to the plants to oversee inspection, inspection taking place by some outside vendor, what are you looking for?

MR. MORONEY: It may be by an outside vendor or by the plant people themselves. Sure.

CHAIRMAN FORD: What are you using as a quantitative guidance, that it's being done correctly?

MR. MORONEY: Right now?

CHAIRMAN FORD: Right now or in the foreseeable future.

MR. MORONEY: Right now I'm not sure there is a quantitative guidance. I mean, there are guidelines that exist that, you know, there are certain standards that, you know, people have to apply. There are, you know, techniques as to how to use the instrumentation and, you know, how to interpret it. And I think our NRC inspectors, a lot of them are capable of making judgments as to whether those things are being done properly. Other than that, you know, I'm not sure I can give you any real detail.

CHAIRMAN SIEBER: Maybe I can tell you a little bit about that. The NRC assures itself that you have an inspection plan and program which is an ISI-type program. And in that plan, you are supposed to use qualified people, and there is a certification process where you are a Level 1, Level 2, Level 3, Level 3 being the most sophisticated of it. And various inspection techniques, like visual, ultrasonic, EDY current, radiography and what have you, and so you assemble an inspection force out of your own folks, or a contractor, train them, and then have them pass these certifications. And the processes that you use, you have to qualify.

For example, you qualify the use of rotating pancake coils and steam generator tubes. You qualify the use of ultrasonics on various kinds of welds, including the material, the configuration and the thickness. And that's all controlled by the licensee's program, which is inspected by NRC inspectors to assure that it conforms to Appendix B and the other requirements and rules. And so that's how the qualification process occurs, so you qualify the person, the operator, and you qualify the process. The instrument then is calibrated with standard cal blocks or whatever it is.

CHAIRMAN FORD: I've seen that demonstrated for steam generator --

CHAIRMAN SIEBER: For everything.

CHAIRMAN FORD: Well, yesterday, Jack, I did not see any quantification of the ability of various techniques or inspection teams in terms of probability of detecting defects in the vessel head penetration sub-assemblies to any specified degree of accuracy. I mean, is that fair to say?

MEMBER ROSEN: No, you said exactly right. We didn't see that yesterday. That doesn't mean it doesn't exist. In fact, it does. And where it exists is in the qualification of the procedures.

CHAIRMAN FORD: Okay.

CHAIRMAN SIEBER: And, in fact, what the RPM folks were trying to explain to us is research process that they were using to find the right way, as opposed to the process you would use to qualify the inspection techniques or individually, and that's where you determine during that qualification what the probability of detection is for various kinds of forums. That's a separate process.

CHAIRMAN FORD: I guess it's a communications problem, because when we asked the MRP people specifically does that data exist like probability of detection, it does not exist. And now I'm asking the NRC people, and I'm not getting a positive reply back giving me competence, you know, that's what -- when they said guidance, review of licensing, that's where they want to go.

MEMBER ROSEN: There's a gentleman up there who wants to talk.

MR. MARSH: I wish I had the answer for you. We don't have --

COURT REPORTER: Excuse me. Would you use the microphone and identify yourself.

MR. MARSH: I'm Tad Marsh on the NRC Staff. I'm sorry, we don't have our DE Staff experts here with respect to the inspection capabilities, and how we go out and inspect, but I'm going to amplify some of the things that you've said.

We do rely in detail on the procedures that are there, the qualification of the inspectors, whether they're Level 1, Level 2, Level 3. Frequently, our inspectors are trained in those same procedures. Frequently, we will have with us contractors who are certified inspectors, as well. And they're trained in those inspection capabilities too, so the experts are not here that lend more than that, but I know we have much more capability than apparently is coming out in this discussion. The quantification that you're seeking is embodied mostly though in the licensee's procedures themselves. Okay?

CHAIRMAN FORD: Thank you very much.

MR. MARSH: All right.

MR. MORONEY: All right?

CHAIRMAN FORD: Stirring it up here.

MR. MORONEY: Okay. I think we're ready to go on to the other part of the thing, the Barrier Integrity Plan, and I'll turn it over to Cayetano.

CHAIRMAN FORD: And this, in terms of the completion date, I'm sure you could

CHAIRMAN FORD:

MR. MORONEY: Uh-huh.

CHAIRMAN FORD: But that's also approximately the end of 2004?

MR. MORONEY: Yes. Or early 2005.

MR. SANTOS: Thanks, Brendan. My name is Tanny Santos. I'm with the NRC Office of Research. And similar to what Brendan has just done for the Stress Corrosion Cracking Action Plan, I'll walk you through the assessment of Barrier Integrity Requirements Action Plan.

This particular action plan is divided in two major areas. Part one deals with leakage detection and monitoring. The second part deals with barrier integrity performance indicators. Next slide, please.

Part one of this action plan, I'll begin with doing reviews of plant technical specifications with regard to RCS leakage and try to identify those plants that might have any non- standard RCS leakage limitations. And another thing we'd like to look at is the plant alarm response procedures for -- pertaining to these leakage detection systems.

The next major milestone, which you'll see on the slide, is to try to develop a basis for new or updated RCS leakage requirements. And this would require some of the tasks that are listed there. Of course, you could begin by reviewing the basis for the current leakage detection systems, and also try to identify those other areas that might be impacted by any change in RCS tech specs or leakage requirements. The first thing would be evaluation, which might be keyed towards the unidentified leak rate capabilities.

MEMBER ROSEN: What kind of --

MR. SANTOS: A leak before break, and what other, you know, impacts might be made by changing RCS leakage limits.

The next task that we'd like to do is to review the industry experience with regard to RCS leakage events, and also try to evaluate the capabilities of the leak detection systems that are in the plants right now. Specifically, we try to look at maybe trying to determine the accuracy, the sensitivity, the reliability of these systems, how well can they pinpoint the location of a leak, if at all, or if they can just quantify a leak to some range, that kind of information.

MS. WESTON: Excuse me. Since these systems are tech spec, most of the big detection systems and the tech specs, how do you plan to effect that? Do you plan to look at possible tech spec changes?

MR. SANTOS: Yes, that's possible. That's one of the areas we're looking to possibly change. Another task would be try to look at the capabilities of new or state-of-the-art leakage detection systems that might exist now that, you know, just aren't implemented in the plant right now. And with this particular task, we'd like to try to expand the scope of the action plan, not to just look at leakage detection systems, but also other technology that can possibly detect degradation before the leakage even occurs.

The first thing that comes to mind would be something like acoustic emission technology that might be able to detect crack initiation and growth before the leakage happens.

CHAIRMAN FORD: Now acoustic emission, you're talking about acoustic emission devices which are not placed on the steel or whatever it is?

MR. SANTOS: It could be.

CHAIRMAN FORD: Just a microphone out in the environment, or something that's on the --

CHAIRMAN SIEBER: The transducer --

MR. SANTOS: Yeah. Right. Exactly.

CHAIRMAN FORD: Okay.

MR. SANTOS: That kind of technology.

CHAIRMAN SIEBER: You usually have a whole bunch of them.

MR. SANTOS: Right, an array.

MEMBER ROSEN: Triangulated.

CHAIRMAN SIEBER: Well, yeah. That's basically what it does, it triangularizes. It gives you a specific point, and that's a way to, for example, do hydros that in an operating plant with pumps running and valves opening and closing, all kinds of stuff going on, oiling.

CHAIRMAN FORD: And these work on --

MEMBER ROSEN: Yes.

CHAIRMAN SIEBER: Yeah, it's strictly acoustic.

MR. SANTOS: Yes. My understanding of the technology - -

CHAIRMAN SIEBER: So you may get a different sound out of plastic than paper, but it works.

MR. SANTOS: And, of course, the reason we'd like to do this is, you know, with the stress corrosion cracks that you might see in some components, the amount of leakage you might expect from those types of cracks might be too low to be detected in the leak detection system.

CHAIRMAN SIEBER: Do you actually detect cracks by sound?

MR. SANTOS: The propagation. From my understanding of the technology, it's the crack propagation.

MEMBER ROSEN: You can hear it crack.

MR. SANTOS: Essentially.

CHAIRMAN SIEBER: I can't imagine -- having listened to some of these things in an operating plant, I can't imagine hearing a crack with everything else that's going on. I mean, it's a noisy place.

MR. SANTOS: Yes, it is, but I believe there has been some --

CHAIRMAN SIEBER: You have to do the analysis.

MR. SANTOS: They have monitored some plants --

MEMBER ROSEN: Dr. Shack is dying to --

MR. SANTOS: Yes.

CHAIRMAN SIEBER: Tell us.

MEMBER SHACK: I mean, they had a research program at PN&L that, in fact, demonstrated that capability in the laboratory. They also demonstrated the capability in the reactor. I mean, the trick is that you actually have to work into a frequency spectrum that's sort of, you know, one that isn't occupied by something else. But, you know, the --

CHAIRMAN SIEBER: Well, cracking has a unique threshold in frequency spectrum. It's different than a lot of other things. For example, different than the leaking valve, for example, or a through-wall leak.

CHAIRMAN FORD: When you -- just looking down this list here, this looks as though it's an in-house technique, evaluation, development process.

MR. SANTOS: Actually, we're thinking of maybe, maybe with contractor support, doing these tasks.

CHAIRMAN FORD: Well, what do the Japanese do, and what do the French do in this regard?

MR. SANTOS: I don't know. I'm not sure what -- as far as what their leakage detection systems use? I don't know, but that would be one of the things that would be incorporated in our list, evaluation of the state-of-the-art, or the --

MEMBER ROSEN: It's my understanding that

Davis-Besse installed some of this.

MR. SANTOS: Yeah. I heard they were also planning on doing some kind of nitrogen detection system or something.

CHAIRMAN SIEBER: Yes. Since the incident, they have.

MR. SANTOS: Right. So there is clearly a place to go --

CHAIRMAN SIEBER: The PWR leakage measurement is pretty -- the fundamental thing that's been there for years actually is a water balanced flow, and it's supposedly accurate to a tenth of a gallon a minute, including all the uncertainties. It is crude.

CHAIRMAN FORD: So you're using this Barrier Integrity Action Plan for essentially two reasons. One is for an on-line monitor of the degradation.

MR. SANTOS: That's a possibility. A possibility for maybe making it a requirement to maybe use an on-line enhanced monitoring system for maybe a critical component, or a component that might be susceptible to stress corrosion cracking. That would be a possibility.

CHAIRMAN FORD: And the other one is to

use that continuous monitor as a basis for meeting a tech spec which might be changed. Is that correct?

MR. SANTOS: Well, no, that the tech specs could be changed, you know, in addition to or, you know, instead of maybe. These are just possibilities of requirements that could be implemented. What we actually decide will depend on, you know, the results we obtain from these studies.

CHAIRMAN FORD: Okay.

MR. SANTOS: I guess the final aspect of this basis document would be try to basically answer the question, what leak rates do you want to try to be able to detect in the plant. You need to evaluate the leak rates that you think might occur or lead to degradation in various reactor pressure boundary components. And maybe then you could use that to compare with the capabilities of these different leakage detection systems.

Next slide, please. Based on the work described on the previous slide, then you could go on and try to make recommendations for improved requirements. Some examples of these would be, you know, developing new or standardized tech specs for these plants, improved inspection guidance for unidentified leakage that would include action levels, that would trigger increasing levels of NRC involvement as the unidentified leakage rate goes up. That was specific recommendation that came out of LLTF.

Another improvement could be maybe the plant procedures for trying to identify pressure boundary leakage from unidentified leakage. Another possibility is, of course, the use of on-line enhanced leakage detection system on certain components that might be susceptible to stress corrosion cracking, or those types of mechanisms. And then, of course, maybe updating, you know, the regulatory guidance on leakage detection system, Reg Guide 145 with some or all of these recommendations.

And then finally you could, you know, incorporate some or all of these recommendations to do requirements using the appropriate regulatory tools, you know, whether it be a backfit analysis, rule making, et cetera. But in developing these new requirements, the point we'd like to really emphasize is we want to try to consider improvements in areas which do not rely just on leakage, because relying just on leakage to assure pressure boundary integrity cannot be relied upon, because problems with the small leak rates associated with tight stress corrosion cracks and those kind of mechanisms. Next slide.

MEMBER ROSEN: By the time you have the leakage we've lost the game.

MR. SANTOS: Exactly. It's too late for pressure boundary integrity. Exactly. And then finally, the second half of the Barrier Integrity Action Plan has to do with performance indicators. The current Barrier Integrity Performance Indicator is giving like 50 percent of one of the RCS tech spec limits. I think it's either the total leakage or the identified leakage, one of the two.

Independent of what the LLTF recommendation in this area was, NRR was already planning on trying to improve this Barrier Integrity PI by incorporating the other reactor coolant system leakage tech specs, as well, to look at both unidentified, total, maybe primary to secondary leak, as well. So that effort was already being planned to do, and has been incorporated into this action plan, as well.

One of the specific recommendations from the LLTF was to develop a PI that could track the number and duration of primary system leaks, so we'll investigate the possibility of developing a PI that could do that, and if possible, implement that.

Another possibility for an advanced PI that we're investigating is a risk-informed barrier integrity PI, examine the feasibility of implementing one of those. And, of course, if that's feasible, develop and implement that, as well.

MEMBER ROSEN: What sort of algorithm are you thinking about, when you say risk-informed barrier integrity PI?

MR. SANTOS: Well, I'm not -- I have to rely on someone else to give more detailed information about that. But the first has to be just to determine the feasibility of something like that, something maybe like looking at wall defection finding might be something along those lines.

CHAIRMAN SIEBER: That wouldn't cover cracking.

MR. SANTOS: Right. Don Dube from Research is the area, and might be able to shed more light on this.

MR. DUBE: Yeah. Donald Dube from Office of Research. What we had in mind is to go back to the, kind of the starting block, if you will, and look at reactor coolant system barrier integrity as more than just hype for a reactor vessel. It encompasses everything from high pressure/low pressure boundary relief valves, motor operated valves, check valves, and the gamut. And when the Reactor Oversight Process started to look at potential indicators for reactor coolant system barrier integrity, they had in mind as broader perspective of what encompasses loss of barrier. That is a precursor to let's say a loss of coolant accident, but because of a number of time constraints and the need to get the Reactor Oversight Process moving, it kind of zeroed in specifically on just percent of tech spec limit, which is what we have now. So in summary, just to go back and look at the broader picture, look at first, are there any other potential mechanisms that could result in loss of RCS barrier.

And then the second part is, okay, maybe there are, but are there any process variables out there that we can use to provide objective measures of loss of barrier integrity. I mean, we may decide that yeah, we want to look at high pressure/low pressure interface, but there's no objective measurable way of turning that into an indicator, in which case we might be at a dead end. But that's kind of the concept.

MR. SANTOS: Then, of course, the final point would be if and when new RCS leakage requirements or barrier integrity requirements are implemented, go back and look at the PIs again to see if they need to be updated in any way. That's the conclusion of the presentation.

CHAIRMAN FORD: Thank you very much indeed. Any questions on this particular segment of the presentation? Thank you very much indeed.

MR. MORONEY: Thank you.

MR. SANTOS: Thanks.

CHAIRMAN FORD: I'd like to ask the members now for thoughts on what we've heard in the last day and a half. And specifically, those which might give advice to the NRC for their presentations to the Full Committee in their next full meeting next month. They've got a two-hour presentation to make to us, so I'd like to hear from us individually as to what has disturbed you, or encouraged you, and what advice do you have. Graham.

MEMBER WALLIS: This two-hour presentation is just by the staff.

CHAIRMAN FORD: Is just by the staff, yes. The MRP are not able to attend. I'm getting advice from my boss here. We'll take advice from you now, and then put it together.

MEMBER WALLIS: I think we need to decide whether it would be good to write a letter or not, what sort of things --

CHAIRMAN FORD: Yeah. What I'm proposing on that one to do, Graham, is I will write a draft letter before the event, and we'll chew it over and see whether there's anything constructive being done with that.

MEMBER WALLIS: Well, I find myself echoing the remarks of the Chairman, looking for quantitative measures of things, real evidence or evidence of understanding of mechanisms and things. You could gather data on operation experience, count the numbers of leakers and all that, but you don't understand what's going on. It's still difficult to predict the future, to anticipate what might happen, make a more rationally-based judgment about things. These inspection programs and so on, I'm not sure that the scientific basis which you're eventually going to need is in good shape. I didn't see much evidence for progress. Anything that could be done to show progress and understanding I think would help me.

CHAIRMAN FORD: Okay.

MEMBER ROSEN: And that ties, of course, to my bone of contention, which is when you do -- when you are fortunate enough to have some operating experience, which is generally painful in this area, the worst thing you can possibly do is to not take advantage of that pain by quickly repairing the thing, and never taking the time to figure out what happened. That's really the only -- that's the most powerful way to find out how to keep these things from happening, is find out what happened, and not relive that particular piece of experience. So it's particularly disturbing to me to hear, at least some of the members of the staff say they have no way of providing regulatory controls to avoid licensees destroying evidence when they conduct repair. That's so counter-productive. And I think we really need to encourage the staff to rethink that, at least those elements of the staff who believe that's true, although the gentlemen we just talked to don't seem to think that's true. And I would also think that the industry itself should, in the MRP process some place, maybe at the higher levels of the MRP process, make it incumbent on themselves not to have that attitude, rather than take every painful experience that occurs and dissect it, and slice and dice it as much as they can, notwithstanding the fact that the plant that happens to have that experience may really, you know, want to get back in service. The right answer for them is get back in service maybe, but the right answer for the industry as a whole is to find out what happened.

CHAIRMAN FORD: Okay. Good point.

CHAIRMAN SIEBER: You'd led off by asking us whether we were either encouraged or disturbed.

CHAIRMAN FORD: Yeah.

CHAIRMAN SIEBER: And to demonstrate my control over my emotions, I am neither encouraged nor disturbed. And I have expressed questions and comments over the last two days that my overall feeling, and it is that we continue to be surprised, and I would like to see us get out of the surprise mode. And I think also that as we collect data, at this point it seems to be weakening the hypothesis a little bit, and that is the empirical equation that describes susceptibility. And with the South Texas information, I think that here's an opportunity, or perhaps a warning, that don't rely too much on susceptibility curves because here's a plant that's clearly not in the susceptibility range, highly susceptible range that has a problem on way or another, and it's paramount that we find out exactly what mechanism for the leakage that we've seen and evidenced was, to be able to determine whether the susceptibility curve is valid, or should be taken with a little bit more of a grain of salt. I don't believe that we are in danger of a major incident. I think there is plenty of inspection going on, both the agency and the industry are paying attention. It's just that we really don't need surprises, and it's fortuitous that South Texas did inspections beyond those that were required for supplying this information. It turns out that it was fortuitous that the deterioration of the Davis-Besse vessel head was actually even found. If they had not dislocated the mechanism by bumping it, perhaps they would be operating today, and so I'm encouraging everyone to maintain an open mind, and to be open to the fact that you can't say because your plant has a cold head, or because you're talking about bottom head which is naturally cooler than anyplace else, that your susceptibility for cracks and leakage is low. And, therefore, I would say if anything the move should be to pretty much classify plants and set the requirements closer together, because unless you can show that the cause of leak in South Texas is not related to stress corrosion cracking, a manufacturing defect, or something of that nature, so that would be my major comment.

On the other hand, I think the staff has done a lot of work. I think the inspection plans that are in place now from the bulletins and now by the order, are producing results, finding things. And that's the purpose of inspection plans. For that, I offer congratulations to the agency and licensees, so that would be my overall impression. I don't know f that's helpful. Perhaps there are those here who don't agree with me. Those are my --

CHAIRMAN FORD: That's what I wanted to --

MS. WESTON: I guess my only comment would be that in light of the recent Sequoyah, Davis, South Texas project issues that I would like to see both the industry and the NRC move with a little more deliberate speed in terms of trying to get some answers here, because we've been proactive rather than -- we're being reactive rather than proactive, and we really need some answers to try to better understand the phenomenon that's going on.

CHAIRMAN FORD: Okay. Can you --

MEMBER SHACK: No. Since I'm working as a contractor on related issues, I don't think I want to make any comments at this point.

CHAIRMAN FORD: Fair enough. Tom.

MEMBER KRESS: Yeah. With respect to being encouraged versus discouraged, I'm very encouraged. I think the staff and the industry recognizes the importance of this problem, and are treating it very seriously. And are, in fact, on the right track.

In my mind, when we get around to finally developing 50.55a rule, there will be two viable ingredients of this program that need to be emphasized, and that is, it is essential that the crack detection and sizing methods be qualified for this geometry and these conditions, paramount conditions. And qualified in the sense of quantification of the probability of detection at given sites, and the probability of non-detection.

The other part that's essential to developing a good rule is to have a validated and conservative model for crack growth rate. And this has to include uncertainties, as well as the probability of a crack. Those two things will be sufficient to allow you to develop an inspection program, and an inspection and repair program for the top head. And so those are the things I would emphasize right there.

Now with respect to the South Texas problem, I think we need to rethink our overall objective there. The overall objective at the top head is to, as I said, preserve barrier integrity, but I interpret that to mean to have no leakage, which means you have to stop the crack in an inspection period before it gets a certain depth through the thing. But that's probably the objective of that. I think you ought to rethink that for the bottom head. I think you've got to rethink whether or not you can live with some leakage, because I think the only way you're going to find that, whether you have a crack down there, is by virtue of leakage. And I think staff needs to think about that as a potential regulatory position for the bottom head.

I think, for example, with respect to the frequency of inspections, I think each plant ought to be able to specify its own frequency of inspection, and the time for the next inspection. With respect to the crack growth models that are conservative, I think those can be plant-specific, but I think as one proceeds with this crack growth and inspection process, that you use a basing and update to your model to get better and better with it as you go along, on a plant-specific basis.

Of course, you have to have certified inspectors and qualified techniques, and this goes to -- that's my thoughts on it. I think we need a letter.

CHAIRMAN FORD: Yeah.

MEMBER KRESS: But I want to repeat, I think the staff and the industry are on the right track, and there are enough programs in place to get this done or under control.

CHAIRMAN FORD: My views are that yes, I think we are on the right track. What disturbs me is that we've gone from three years ago, four years ago very much in a reactive mode, to the CRDM circumferential cracking, to coming up with an approach for that. Then went to a more proactive approach for that, then went to reactive, then to proactive as we've met these various stumbling blocks as we go down the line.

I agree that we've got to have a holistic approach to it, as the industry said. We cannot distribute the VHP assemblies in isolation from the bottom head and from the pressurizer, so any prioritization algorithm that we have has got to take into account not just temperature, but also material and stress conditions to some degree or other.

I think it's good that we have a revised action plan with the four parts to it. I have a feeling that it is overly optimistic, and I agree with

Graham that there should be much more of a tone of understanding of some of the fundamentals behind it, which will therefore increase the -- or decrease the degree of uncertainty.

What I'll do is I'll formulate a letter which I'll pass on to everybody in terms of our suggestions for the staff as to how they formulate a time, and prioritize the time, but I suspect probably it would be along the lines of having Al update us on the situation from the bulletins and the orders. Then go into the plan outline and then have Research give some outline of how they're going to tackle some of the parts to that plan. We'll follow-up on those recommendations.

MEMBER KRESS: On the effective degradation years. I think we're going to have to have a debate on that in Committee, because I still think it's an appropriate way to prioritize for current where you're going. I think it's going to take too long to get these other unknown effects into it, and I think what we have with the effective degradation years, based on Oconee as a baseline, is somewhat conservative. It may miss plants that aren't degraded, but it'll catch the ones that are. And I think it's probably an appropriate way to go right now, as we have. And I don't think South Texas changes that. Again, it's a personal opinion.

CHAIRMAN FORD: Okay. Are there any other comments from anybody in the audience? Al.

MR. HISER: I just have one comment.

CHAIRMAN FORD: Yes.

MR. HISER: Right at the end, and it's maybe a little bit off target.

[THE DISCUSSION HAS BEEN REMOVED DUE TO PROPRIETARY INFORMATION]

CHAIRMAN FORD: Are there any other issues, any other comments? Paul.

MR. GUNTER: Paul Gunter with Nuclear

Information Resource Service. I would just only add that we concur that we've long been disturbed by the issue of evidence -- I should say the issue of repairs without an autopsy, or the removal of evidence, destruction of evidence in haste for repair. And in particular, we were disturbed by the removal of corrosion products even in the wash-out of the Davis-Besse cavity, where I think that there could have been a lot gained by a chemical analysis of what was in that cavity, and that was just all washed-out. So the question is, how far do you -- I mean, where do you begin the recovery of evidence. And what are the initiating opportunities for recognizing that evidence.

CHAIRMAN FORD: Thank you. If there are no more comments, then I will call and end to this meeting, or whatever the proper language is.

MS. WESTON: Adjourned.

CHAIRMAN FORD: Adjourned.

(Whereupon, the proceeding in the above-entitled matter went off the record at 2:20 p.m.)