Official Transcript of Proceedings ACRST-3239

NUCLEAR REGULATORY COMMISSION

ORIGINAL

Title: Advisory Committee on Reactor Safeguards 502nd Meeting

PROCESS USING ADAMS
TEMPLATE: ACRS/ACNW-005

Docket Number: (not applicable)

Location: Rockville, Maryland

Date: Thursday, May 8, 2003

Work Order No.: NRC-909

Pages 1-229

NEAL R. GROSS AND CO., INC.
Court Reporters and Transcribers
1323 Rhode Island Avenue, N.W.
Washington, D.C. 20005
(202) 234-4433

TR04

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

+ + + + +

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

502nd MEETING

+ + + + +

THURSDAY

MAY 8, 2003

+ + + + +

ROCKVILLE, MARYLAND

The Committee was called to order at 8:30 a.m., at 2 White Flint North, Room T2B3, 11545 Rockville Pike, Dr. Mario V. Bonaca, Chairman, presiding.

COMMITTEE MEMBERS PRESENT:

DR. MARIO BONACA	ACRS Chairman
DR. GEORGE E. APOSTOLAKIS	ACRS Member
DR. F. PETER FORD	ACRS Member
DR. THOMAS S. KRESS	ACRS Member
DR. GRAHAM M LEITCH	ACRS Member
DR. DANA A. POWERS	ACRS Member
DR. VICTOR H. RANSON	ACRS Member
DR. WILLIAM J. SHACK	Acting Member
DR. JOHN SIEBER	ACRS Member
DR. GRAHAM B. WALLIS	ACRS Member

ACRS STAFF PRESENT:

JOHN T. LARKINS	Executive Director, ACRS, Designated Federal Official
SHER BAHADUR	Associate Director, ACRS
HOWARD J. LARSON	Special Assistant, ACRS
SAM DURAISWAMY	Technical Assistant
MAGGALEAN WESTON	Cognizant Staff Engineer, Designated Federal Official, P.M. Session
MICHAEL R. SNODDERLY	ACRS Staff Engineer
BILL BECKNER	NRRR
RALPH CARUSO	ACRS Staff
FRANK GILLESPIE	NRR
ALLEN HISER, JR.	NRR
JOSE IBARRA	DSARE/RES
DOUGLAS KALINOUSKI	RES
BRENDAN MORONEY	NRR/DLPM
WILLIAM H. CULLEN, JR.	RES/DET/MEB
RICHARD BARRETT	NRR/DE
TERENCE CHAN	NRR/DE
MATTHEW MITCHELL	NRR/DE/EMCB
CHARLES ADER	RES
SYED ALI	RES/DET/ERAB
STEPHEN DINSMORE	NRR/DSSA/SPSB
ANDREA KEIM	NRR/DE/EMCB

I-N-D-E-X

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

(8:30 a.m.)

CHAIRMAN BONACA: The meeting will come to order. This is the first day of the 502nd meeting of the Advisory Committee On Reactor Safeguards. During today's meeting the committee will consider the following.

One, vessel head penetration cracking and degradation.

Two, proposed revisions to Regulatory Guide 1.178 and Standard Review Plan, Section 398, for risk-informed in-service inspection piping.

Three, operating experience, program effectiveness, draft Commission paper on the ACRS self-assessment, and proposed ACRS reports.

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

We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions. A transcript of portions of the meeting is being kept, and it is requested that the speakers use one of the microphones, identify themselves, and speak with sufficient clarity and volume so that they can be readily heard.

Before we move to our agenda, I would like to draw your attention to items of interest. There are four speeches by the Commissioners provided during the regulatory information conference that took place in Washington on April 16th and 17th, and also some interesting issues about the operating plants.

With that, I would move to the first item on the agenda, and that is vessel head penetration cracking and degradation. We had a presentation scheduled by the NRC and I believe that Dr. Ford is responsible for this presentation, and will walk us through.

MEMBER FORD: Thank you, Mario. This segment addresses the question of vessel head penetration degradation. At the March full meeting, full ACRS meeting, we had presentation by the ERPI materials reliability program on this issue and how they are going to manage it.

And at that the Combined Materials and Plant Operation Subcommittee meeting on April 22nd and April 23rd, we heard both from the industry and from the NRC staff.

Today we are going to hear solely from the staff, and an update of the inspections, findings, and also on the lessons learned task force action plan, and where we are going on that plan. I will ask Dr. Hiser to start.

DR. HISER: Good morning. I am Allen Hiser with the Materials and Chemical Engineering Branch of NRR. What I would like to do today is provide you with an update on the status of pressure vessel head inspections, and in particular I would like to go through a little bit of background on findings over the last several years and NRC actions in response to those findings.

I want to describe the order that was issued approximately 3 months ago, and go over some recent plant experience for high susceptibility plants this spring, and also some findings on the lower head at the South Texas Project, Unit 1.

And then to wrap up, I want to provide a little bit of an outlook of where we think we are going in the future, and then describe what industry is doing, and how that feeds into a resolution of this issue.

The next three slides provide some detailed background. I don't want to go over this in too much detail, but this issue from the standpoint of findings of degradation in the United States really initiated in the fall of 2000 with the finding of deposits at Oconee Unit 1.

And following that in the spring outage season, two units at Oconee identified leaks, and also identified circumferential cracks in their nozzles at a location that could promote loss of coolant accident.

In response to that the NRC issued Bulletin 2001-01 in August of that year. The next spring, Davis-Besse identified head wastage and circumferential cracking in their nozzles.

In response to that, we issued another bulletin in March of 2002 that really focused on the safety issue of RPD head wastage for all PWRs. Last summer, we issued Bulletin 2002-02, and there was sort of a shift from the prior two bulletins from a focus of the safety concerns of circumferential cracking and nozzle ejection, and head wastage, to more implementation of inspection programs that would carry forth into the future.

In particular, the methods that were described in this bulletin were both non-visual and visual NDE. The bulletin talked about the methods and also the frequency that would provide a program that would be effective in controlling these issues.

Licensee responses were generally vague on their future program activities regarding the next outages. The responses were very consistent with the bulletin described and would appear to provide for effective inspections.

The inspection tha we had in reviewing those responses is that for the future inspections there was not a significant commitment there by licensees.

Some of the responses were vague and also many of them cited a report from the industry described as MRP-75 at that time.

And still today the staff has a lot of concerns of the adequacy of the inspections described in that report. Following the issuance of Bulletin 2002-02, many inspection findings in the fall continued to indicate that the problem was not well in-hand.

In particular, North Anna Unit 2 identified prevalent weld cracking and ultimately decided to replace their head in an expedited manner. In addition, Oconee Unit 2 identified possible through wall cracking without boron deposits on the head.

This was inconsistent with the general approach in the MRP bulletin, or the MRP report. As well, Sequoyah Unit 2 identified corrosion of the outer surface of the upper head, and the source of boron in this case was not from nozzle leakage but was from a source above the head.

And that identified a new problem area that we needed to address. In response to sort of the overall history and a desire to provide some continuity and consistency in this area, the NRC did issue an order in February, and this order mandates specific inspections of all PWRs.

And what I will do over the next few slides is go over some of the details of the order.

MEMBER LEITCH: That was February of '03 was it not?

CHAIRMAN BONACA: '03.

DR. HISER: Thank you. And what I will also do then later in the presentation is describe some of the recent findings at South Texas Project Unit 1, where boron deposits have been identified, not on the upper head, but on the lower head.

MEMBER FORD: Before you move away from that one, Allen, on the question of the ANO Unit 1, where you have a leak through a repaired nozzle, that repaired nozzle was prepared with Alloy 52; is that correct?

DR. HISER: Yes, that's correct.

MEMBER FORD: And will you be talking about that specific instance later on?

DR. HISER: I did not have plans to do that, but we can if you would like.

MEMBER FORD: Well, it is important to touch upon, since it was repaired with the alloy that will be used for all of the replacements, and it does touch upon the weldability of Alloy 52.

Maybe at some appropriate time during your presentation you could touch on that.

DR. HISER: Okay. We will do that. Now, the orders were issued on February 11th of 2003, and not 2002. These were issued to all PWRs. The basis was inadequate protection.

In particular the ASME code mandated inspections are not adequate in this area. Revisions to the ASME code requirements, and in particular implementation of those requirements to PWRs is not imminent.

RPV head degradation and nozzle cracking do pose safety risks if they are not promptly identified and corrected. With the issuance of this order, we now have a clear regulatory framework for inspections of the upper head area.

And this is clearly pending incorporation of revised requirements of 10 CFR 50.55a.

MEMBER FORD: Could you just make a quick comment as to why the current ASME code inspections are inadequate? Just very quickly.

DR. HISER: The current inspections are a visual inspection, and the ASME code does not require removal of insulation for inspection of the bare metal of the pressure vessel head.

The quantity of deposits that have been identified from leaking nozzles tend to be very small, on the order of square inches, or cubic inches, and the inspections just really are not sufficient to identify the problem.

And consistent with the bulletins that we have issued, the order does require an evaluation of susceptibility for each plant, and this is in terms of a quantity called effective degradation years, which is based on the operating temperature and time.

In particular, there is a normalization in this calculation to an operating temperature of 600 degrees. The higher the operating temperature for a plant. the rapid the accrual of effective degradation years, and clearly the longer the plant operates the higher the effective degradation years would be.

Now, for high susceptibility plants, the order requires both bare metal visual and non-visual, non-destructive examination at every refueling outage. For moderate plants, the bulletin or the order requires bare metal visual and non visual NDE at alternating refueling outages.

So a licensee does not have to do both at any particular refueling outage. What they must do either is visual or non-visual NDE at each outage. For license susceptibility plants, the bare metal visual is required by the next two refueling outages, and then is repeated every third refueling outages or every five years.

And the nonvisual must be performed by 2008, and then repeated every fourth refueling outage, or every seven years thereafter.

MEMBER FORD: Just to remind us, the subdivision between those three categories is somewhat arbitrary, in terms of the affected degradation years, which goes from moderate to high, or whatever. It is -- there is no science behind it, and it is purely an arbitrary choice of EDY. Is that correct?

DR. HISER: I would say it is more

empirical based on the findings, the --

MEMBER FORD: I didn't mean arbitrary choice.

DR. HISER: There is no scientific basis that would indicate that the divisions that are made in the order are the correct divisions.

The points or the criteria that are in the order were based on a review of the operating experience, and so far with the inspections this spring, I think they confirm the validity of those.

And the choice of the inspection methods, bare metal visual, et cetera, is again just pure engineering judgment. It is not based on any risk or delta CDF, or anything like that. It is just purely engineering judgment?

DR. HISER: It is engineering judgment with an intent to provide a timely detection and remediation of both cracking and leakage. With the inspections that are required for the non-visual NDE, the intent there is to be able to identify any degradation before it becomes through wall, and can provide leakage to the head.

So that is really one of the intents of these inspections.

MR. BARRETT: Could I add a word to that?

This is Richard Barrett, and I am with the staff. I think that when we have looked at the finalology here, we identify a couple of different ways that the cracking can lead to failure of these tubes.

One being cracking through the weld, and another being cracking, axial cracking through the tube itself. And then the third phenomenon of course is the wastage phenomenon. And in selecting the requirements for the order, what we tried to do was, was to get a combination of inspections that could identify either of those two phenomena leading to failure or rupture of the tube.

And in addition address the wastage issue, and so that was the thinking and it was a logical process that led to this. I think that is fair to say, isn't it, Allen?

DR. HISER: Yes.

MEMBER APOSTOLAKIS: Now, I have a question. Peter, why did you say there is no scientific basis for EDY? I mean, where were you going with that? If it has worked in practice, what would be the problem with it?

MEMBER FORD: Well, the issue will come up as obviously the conversation goes on as to whether it is adequate EDY as we look at all of the inspection findings that we have gotten so far.

Fundamentally, it is a simplistic algorithm, EDY, and it is probably a good engineering judgment at this stage, but you have to question it, and that's why I was asking the question what was the criteria to define whether you go from moderate to high or low to moderate, et cetera.

And Allen says, it was to a certain extent engineering judgment.

MEMBER APOSTOLAKIS: Is it the conservative judgment here?

DR. HISER: I think at this point it is, yes; and I think that the inspection findings to date, there has been no cracking identified in plants that are not in the high susceptibility range by the order.

CHAIRMAN BONACA: The point that you make, Peter, is that the dependency only from temperature is a simplification, right?

MEMBER FORD: And it is a reasonable simplification given what we knew at the time and this was derived. It is an absolutely reasonable simplification, but it is a simplification, and therefore what risk are we at continuing to use it?

CHAIRMAN BONACA: And the parameters that you mentioned I believe in your correspondence was stress?

MEMBER FORD: Stress and materials.

MEMBER WALLIS: But you are looking for more of a rationale. One of the things would be how long do we wait before every plant has an BMV, and looking at this, it is not very long is it? It is a couple of years or something.

And after a couple of years, every plant would have had a BMV. So you have some sort of criterion here, as well as just arbitrarily saying low, moderate, high.

MEMBER FORD: Yes.

MEMBER WALLIS: Presumably there is some hidden criterion somewhere there.

MEMBER FORD: And that is the reason for the question, and the answer was it is based on engineering judgment.

MEMBER WALLIS: Yes, but you don't expect anything to happen for more than -- you know, for the next 5 years in the low plants. Therefore, we will inspect them and make sure that they all have some sort of an inspection within the next 2 or 3, or whatever it is.

DR. HISER: And I think that's right. These categories really are based on expectations.

For the high susceptibility plants, I think there is an expectation that cracking may occur.

The intent of these inspections is to identify the cracking before it can pose any kind of a safety risk, such as leakage, head wastage, nozzle ejection.

For moderate susceptibility -- well, let me jump down to low susceptibility. I think it would be somewhat surprising if a low susceptibility plant identified cracking on the upper head. Now, as we will talk about a little bit later, the findings at South Texas may pose some challenges to that rationale.

CHAIRMAN BONACA: That's right, and that is the question that I had in fact; does South Texas tell us anything different.

MEMBER FORD: Well, I think what is going to come out of this discussion is that the current algorithm that you have got is incomplete, but it seems to work for the majority of the plants, provided it is only the vessel head that you are looking at, and the residual stresses which are common to the vessel head.

And go to another penetration and we might have a completely different residual stress profiles.

You would not expect that algorithm to still apply, and I think that is true, isn't it, Allen?

DR. HISER: Yes, I think that is correct. For the upper heads, the fabrication processes are very similar, and the geometries are similar, and the welding is similar. So I think that the findings that we have are internally self-consistent.

If you begin pulling data, for example, from the lower head, then it may be that you are looking at a different population. It may be that EDY may be effective, but there is a different relative scale that you need to use for the lower head relative to the upper head.

That is speculation, and we need to allow some of the results from South Texas to be firmed up, in terms of the source of degradation.

MEMBER SHACK: When you talk about the spread of EDY on the lower head, because they probably all operate closer to the same temperature, I am assuming --

DR. HISER: There is a fairly good spread.

MEMBER SHACK: There is a good spread?

DR. HISER: Yes, and actually I think South Texas is relatively high in the cold leg temperature, which is correlated with the lower head temperature. So it may be that South Texas may be the leading indicator on the lower head, much as the Oconee units were on the upper head.

We need to gather additional information to understand that better.

MEMBER LEITCH: When a plant replaces their head, the advantage that they gain is just resetting the timer so to speak. In other words, they would move into the low susceptibility category because there is zero hours on the new head?

DR. HISER: Right.

MEMBER LEITCH: There is no recognition in the order that new heads -- that the penetrations are of different material than originally? In other words, there is no recognition for different materials.

DR. HISER: At the present time the order makes no distinctions between Alloy 600 heads and Alloy 690 heads. But when a plant does replace their head the EDY does reset to zero and then they begin to accumulate again.

For example, a new Alloy 600 head, such as Davis-Besse has, would accumulate EDY at a proportional manner, the same as the North Anna, Surry, Oconee heads that use Alloy 690 in the nozzles.

MEMBER LEITCH: But the order just applies to head penetrations. For example, you could reset the timer so to speak with replacing the head, but yet still have some old 690 penetrations in other parts of the system, and the order does not specifically address that; is that correct?

DR. HISER: Yes, the order only addresses the upper head and all of the penetrations in the upper head would be 690, other than I guess the one case of Davis-Besse, where they do have a head that is fabricated from Alloy 600 nozzles.

MEMBER LEITCH: Okay. But the other 690 penetrations are not really addressed by the order, just head penetration?

DR. HISER: No. The order only addresses -- and only the upper head. The lower head is not described or discussed in the order in any way.

MEMBER LEITCH: Okay. Thank you.

DR. HISER: Okay. The non-visual NDE that the order specifies is either an ultrasonic exam, or wetted surface examination, and just to illustrate what those mean, I use this figure. The purple areas illustrated on the top surface are the areas that are covered by the bare metal visual inspection, and it does not come out very well.

MEMBER SHACK: You need another color selection.

DR. HISER: Yes. And the bare metal visual again applies to all plants, just at various frequencies. The ultrasonic inspection involves an examination of the areas covered in green here, would be basically the nozzle inside diameter, and looking for cracks in the nozzle base material itself.

Now, the nozzles on the upper head have an interference fit zone in which the outside diameter of the nozzle is larger than the whole diameter in the head, and so that provides a good metal to metal contact.

The order specifies that licensees must assess leakage through this interference fit zone. One technique that is used by vendor -- inspection vendors is to interrogate the ultrasonic data in that area. So that is one approach that is addressed in the order.

MEMBER WALLIS: So this stainless steel tube is driven into this hole?

DR. HISER: Actually, it is called a shrink fit approach. And what hey do is they chill the nozzle --

MEMBER WALLIS: Yes, but it is not driven in any way where it would scratch the surface?

DR. HISER: No.

MEMBER WALLIS: And when you said there was interference, I was not clear on how they put it in.

DR. HISER: Yes.

MEMBER WALLIS: Or inconel tubes.

DR. HISER: And actually one point is that there is an interference fit at ambeit temperature where the inspections are performed, and at operating temperature, it appears that all nozzles and all heads have some sort of a gap from the J-groove weld area up to the top of the head, such that eventually any leakage would put a deposit on the head. So that is one --

MEMBER WALLIS: They grow and swell when that heat isn't cooled down, and it puts stresses on the welds?

DR. HISER: That's correct.

MEMBER WALLIS: And they grow and swell, and constraint, and all of that?

DR. HISER: Yes.

MEMBER WALLIS: And that is yanking the welds?

DR. HISER: That is correct. Now, the

wetted surface exam involves an examination of the entire surface of the wetted surface of the J-groove weld, and the nozzle.

MEMBER WALLIS: UT or what?

DR. HISER: No, the wetted surface would either be normally an eddy current exam, or possible a combination of eddy current and dye penetrant test, and what that exam looks for is surface breaking flaws in the J-groove weld surface or the nozzle base material.

So that is a little bit of orientation. Now, the order does provide explicit requirements and criteria for inspection of repaired nozzles and J-groove welds.

Based on the findings at Sequoyah last fall, at each refueling outage, every PWR must perform a visual inspection of the area above the head to identify potential sources of boric acid that could provide boric acid on to the surface of the head.

If there are any possible sources or possible leaks, then follow-up inspections or follow-up actions are required. They would require inspections of the potentially affected RPD head surface, and also the nozzles that could be affected by that source of boron.

Flaw evaluation is prescribed in the order per NRC guidance. In particular, the order describes a letter from Jack Strosnider to NEI in the fall of 2001. We have just recently issued a revision to that guidance that incorporates more recent crack growth rate equations.

And as we described earlier, the orders apply also to new RPV heads, be they the Alloy 600 head used at Davis-Besse, or Alloy 690 heads. We have had extensive discussions with the industry on Alloy 690 and they are beginning to provide the technical basis that would or could lead to some reduction inspections for the Alloy 690 heads.

At the present time, we don't have a technical basis to do that. So in lieu of that, we treat the two the same. In addition, there is a post-outage report providing the inspection findings that licensees are required to provide 60 days after they restart.

In response to the order, licensees had an opportunity to respond within 20 days. They could have requested a hearing, and they could have requested a time extension to respond to the order, and in no case did that occur from any license.

The order does provide for the Director of

NRR to relax or rescind specific requirements of the order. For specific nozzles a request for relaxations will be evaluated using procedures for proposed alternatives to the ASME code in accordance with 10 CFR 50.55a(a)(3).

And that does not mean that these are relief requests. They are relaxation requests. It is just that the overall process that we use is similar. One difference is that the NRC must issue a written approval of the relaxation prior to restart with relief requests, and we are allowed to do that through a verbal feed.

MEMBER WALLIS: And the subcommittee meeting, you showed us some examples of plants where they have great difficulty actually doing this because of the way that they were designed and put together.

DR. HISER: Right.

MEMBER WALLIS: And are you going to say the same thing about that --

DR. HISER: I have some graphics to show some of the problems.

MEMBER WALLIS: And what are you going to do about those? The question is not just that there is a problem, but how are you going to resolve it?

DR. HISER: We have evaluated the

significance of the non-inspected area, and to date have found those relaxations to have merit, and to be consistent with the order.

MEMBER WALLIS: So you are going to let them not inspect according to the order?

DR. HISER: Generally, or the criteria that we have used to review those reliefs are indicated here, and the ones that have been approved within either one of these two criteria, and in particular the proposed alternative must provide an acceptable level of quality and safety, and the way that we have implemented that is that the area of non-coverage must have a minimal safety impact.

For example, stresses must be very low, and the likelihood of cracking must be very low.

MEMBER WALLIS: You just are assuming that you can evaluate all of these things, and you are operating in an area of considerable uncertainty, and you are not inspecting something which really should be inspected.

You are rationalizing that in some way, and it is a bit like what the problem is that caused this in the first place, and not enough attention to nozzles on top of a head.

DR. HISER: Well, the areas that are not

being inspected generally are the bottom of the nozzle, where stresses are low. They are barely high distance from the pressure boundary, and if cracking does occur there, it would take time for that to grow into the pressure boundary.

In the interim time there would be examinations of that intermediate material that would identify the cracking. It is based on things like that that --

MEMBER WALLIS: Well, if you were wrong what would happen?

DR. HISER: If we are wrong --

MEMBER WALLIS: If you are wrong, you left them and did not inspect, and they really did have a leak up there, what would happen?

DR. HISER: If there would be a leak, it would be through a limited portion of the cycle, and no adverse effects would occur.

MEMBER WALLIS: It would be detected before it got too bad?

DR. HISER: Yes.

CHAIRMAN BONACA: Even with the low susceptibility plants that are not inspected frequently?

DR. HISER: For the low susceptibility

plants, there are not frequent visual inspections at this point. There have been no relaxation requests or approvals for low susceptibility.

CHAIRMAN BONACA: Okay.

MR. BARRETT: If I could add that I think it is fair to say that these exceptions have in fact been exceptional in a sense that I think you would find that by and large they have been -- the exceptions have been for a limited number of tubes and have allowed for a great deal of coverage of the tubes in which there are exceptions. So I don't want to leave you with the impression that there has been wholesale exceptions made to this order. We have actually been --

MEMBER WALLIS: Well, I think you ought to consider what if you are wrong, and suppose that there is a leak in these inaccessible places that you could not inspect. You have to be assured that the consequences wouldn't or couldn't be something very, very undesirable.

MR. BARRETT: Right, and I think another think to put this in perspective is that as Allen pointed out, when we first discovered this cracking, these cracking phenomena, the bulletins that we issued were for interim compensatory type measures.

Bare metal visual inspections, which at that time were a big step forward from what was required in the ASME Code, and in those cases if we were wrong, the possibility was that there was some -- that there was degradation in somewhat of an advanced stage.

Today the order that is out there for the effort had or I think goes a long way towards restoring some of the margin that we thought was originally there.

So that we are looking now to prevent the type of conditions that could lead to a circumferential crack, for instance, which could in-turn grow and lead to a failure of the tube.

So we have taken this to a new stage of margin, I believe, with this order. And I think to answer your question, the consequences of a failure today in an inspection in compliance with the order would be far less than the consequences of a failure with regard to compliance with the bulletins that we issued in 2001 and 2002.

CHAIRMAN BONACA: I see you have some slides addressing some of the exemptions of the request, and so that would be interesting, too.

DR. HISER: I think as we go through some of the graphic examples, I think it will become clear the inconsequential nature of the relaxations.

CHAIRMAN BONACA: And I understand some of the repairs with new repairs also have been focusing on cracks. Will you talk about that point?

MEMBER FORD: That's what I asked to be included.

DR. HISER: Now the need for the orders is described on this slide, and really the first four bullets really lead to one specific goal, and that is consistency.

The orders are intended to be an interim measure until rule making can be implemented to get new inspection requirements in place, and new effective inspection requirements in place.

In addition the order addresses the Sequoyah degradation last fall from a source of boron above the head, and that I think is a key part of the order as well.

Now, one part of the order describes a flaw evaluation criteria. As I mentioned we had issued a letter that is specifically referenced in the order from 2001, and we have recently issued a revised letter.

In addition, the ASME Code has implemented or I guess approved a code action in this area for flaw evaluation criteria. What I wanted to do was just to highlight some of the differences in the two letters, and then one difference with the ASME code, the flaw acceptance criteria in terms of where flaws are located, the extended flaws that are acceptable, actions that must be taken, are identical in the two letters.

There is one difference, in that Section 11 standards are not allowed in the new letter. In particular the 5 percent through wall limit that is allowable by Section 11 is not endorsed in the April 11th letter.

The crack growth rate in the initial letter was a 9550 evaluation of the data from a preliminary database, and in particular that was a 95th percentile bounding curve with 50 percent confidence.

The April 11th letter incorporates a more robust database analysis by the MRP, and in that case it is the 75th percentile.

MEMBER WALLIS: It is the 75th out of data points which are all over the paper.

DR. HISER: It is the 75th percentile of individual heat data.

MEMBER WALLIS: But that is not the notorious figure with the points all over the paper, and someone drew a curve sort of in the middle of it, and that is the 75 percent?

DR. HISER: I would -- well, actually, it is really not the 75th percentile of those data, those individual data points. It is an analysis of the individual heat data in the 75th percentile based on that data.

MEMBER WALLIS: But it still is subject to a lot of uncertainty, a great deal?

DR. HISER: Yes, that's correct.

MEMBER POWERS: Why at 75 percent?

DR. HISER: The 75th percent is, if you will, the middle of the top half of the database.

MEMBER POWERS: The middle of the top half?

DR. HISER: If you --

MEMBER WALLIS: That's where the students get A's.

MEMBER POWERS: No, B's.

DR. HISER: It is not an upper bound, but a median curve for the top half of the data. I think that some of the thinking on that is that if you want to split the materials into high susceptibility, and low susceptibility, and so if you ignore the bottom 50 percent of the data, and now focus on if you will the susceptible materials, this would be a mean curve through "susceptible" materials. That would be one interpretation.

MEMBER POWERS: One interpretation might well be that one out of every four things gets missed.

DR. HISER: I think implicit in that would be a statistical expectation that some cracks may grow faster than this analysis would indicate, that's correct.

MEMBER POWERS: For the life of me, it is just a mystery. I mean, if you had written 95, I would probably ask the same question. But at least 95 has at least some pedigree in it, and I see it a lot. In 75, I see it only when somebody is trying to hide something from me.

DR. HISER: At this point this is the industry proposal, and we think that as an interim measure again that it is reasonable. We are evaluating the analysis --

MEMBER POWERS: I am trying to understand the reasonable behind the reasonable here

MEMBER WALLIS: The reason is that it is an industry proposal, and that's why it is 75 and not

95.

DR. HISER: Well, if we thought it was necessary to use the 95 percentile as an interim measure, then we would be using that, but at the present time we don't --

MEMBER POWERS: Why do you think it is necessary to use 75?

DR. HISER: As a -- well, consistent with normal ASME code evaluations, a 50 percent curve would be used. So this is more conservative than a normal ASME code evaluation.

MEMBER POWERS: So it would not be grossly unfair on my part to say that it is a number pulled out of the air?

DR. HISER: I think there is some engineering involved in it.

MEMBER POWERS: A limited segment of the air. The mean value of the upper half of the air.

MEMBER KRESS: When you get around to making a permanent rule, which is going to have inspection frequencies in them, and inspection frequencies will probably be determined by the depth of the cracks and their growth rate, I hope that you don't use this criteria for the growth rate.

It would be more appropriate in a

regulatory space to use something like a 95, because your objective is to have no crack penetrate the wall, and so you want to be fairly confident of that, and so it may be all right in the interim to use this, but when you get around to the final rule, you might have trouble with this committee on that particular issue.

Well, most of the 95, 95 is way up in growth rate. It is an order of magnitude higher. So you are not at all being conservative. There are growth rates which are way above this 75-50.

DR. HISER: And again the purpose of this is evaluation of flaws that are found. There have been some flaws found in the spring, and the licensee actions are generally to repair the flaws, and not perform this evaluation.

MEMBER KRESS: The other concept is -- you know, I am concerned about the final rule. I don't think you want to lock in something like this other than for a specific plant. I think you can use a Bayesian update as you inspect and then get more data for that particular plant, and you can end up with a plant specific type of growth rate, and I hope that kind of concept shows up in the final rule.

DR. HISER: Okay.

MEMBER FORD: Before you move on to --

well, you are about to move off this?

DR. HISER: No, I just wanted to touch on one other part of this. The ASME code for certain configurations allows for a case-by-case evaluation and approval by the regulatory authority.

Both of these letters specify that certain circumferential cracks at and above the weld, and outside diameter axial cracks above the weld, must be repaired. So that is one deviation from the ASME code action.

MEMBER FORD: I noticed that you have got fatigue in there, which is obviously the addition of an extra degradation mode is conservative. Is there a reason or a reason for supposing that fatigue will be a major contributor to this particular --

DR. HISER: No, I think that is included in our letter just for consistency with the code action, and the way that the ASME code routinely treats all degradation modes.

MEMBER FORD: Also in the guidance letter you give the form of the residual stress profile. What is your expectation when a licensee comes along with such an analysis that he has qualified that residual stress profile against data?

DR. HISER: Generally, plants are using

plant specific stress and --

MEMBER FORD: Yes, but that residual stress profile through whatever LOCAs that you want to choose is by calculation or calibration.

DR. HISER: That is correct.

MEMBER FORD: What is the qualification of that calibration or that calculation against data? Is there an expectation from the NRC that they must show some reason, assuming that finite analysis is correct? What is the uncertainty of it? Do you understand what I mean or I am getting at?

DR. HISER: Yes. There are plans by the industry to do some benchmarking of calculations with measurements from J-groove welds.

MEMBER FORD: Okay.

DR. HISER: And at the present time, we have compared calculations from the industry with an NRC contractor and they have found good agreement between those two, but the level of benchmarking to actual physical measurements I think is limited at this point.

MEMBER FORD: And the final question on this particular item is that in the guidance data you give some acceptance criteria for the flaw size, is a function of position and orientation.

DR. HISER: Right.

MEMBER FORD: And that is a mandated acceptance criteria. What is the NRC's expectation that the licensee can meet in terms of inspection, technique, and probability of detection, that they can meet that criterion?

Now, when you say it is a quarter wall thickness or whatever the criterion is, and they say, yes, we can meet that, how do you know that they can meet that expectation of flaw depth, size, et cetera?

But I think it is implicit that the inspection uncertainty is below certain levels, and that has been demonstrated through blind testing at the MRP.

MEMBER FORD: So the NRC has accepted those tests as being done by the MRP so far that we saw since earlier this month, or at the end of last month?

DR. HISER: Maybe Terrence can speak a little more specifically to how we have looked at that.

MR. CHAN: I am Terrence Chan with the staff. We have sent people out to look and witness the qualification and NDE demonstrations that have been performed, and they are for the most part, they have not been blind tests, in terms of the qualification of the equipment.

For the personnel, they are blinded and that is my understanding, and they are using performance demonstration criteria, and they are able to depth size, and they are able to link size to certain criteria, and it is that that gives us confidence that they are able to meet the criteria that is set out in the guidance.

MEMBER FORD: So the licensee has demonstrated each one and he comes along with this case, and he has demonstrated that inspectors have a certain probability of detection, and that goes into your evaluation; is that correct?

MR. CHAN: The POD does not. No, there is no -- no, the POD does not go into the evaluation.

MEMBER FORD: Okay. Thank you.

MEMBER LEITCH: I am confused by the force of regulation of these two letters. The first one, if I understood you correctly, is incorporated in the order by reference. Is the second one now the one that industry is following? That is, the April '03 letter?

DR. HISER: We would expect that the April '03 letter would be -- the order actually references the November letter, and further updates for the revisions as they are made.

So we would consider the April letter to be the appropriate guidance.

MEMBER LEITCH: So that the order, or by the revision to the letter, the order then de facto has been modified? In other words, the order allows for subsequent revisions to the November '01 letter?

DR. HISER: That's correct. And within this context I think the crack growth rate is probably the most significant modification.

MEMBER FORD: I am just looking at the time here. It is appropriate that we spent the time on the order. Can we finish your presentation by half-past-nine?

DR. HISER: Let me describe what I have to present and you can tell me which you would prefer. In the next few slides, they are just a description of the relaxation requests.

Following that, I have a little bit of discussion of high susceptibility inspection findings, and then the remainder is South Texas findings, and then a little bit future looking outlook and industry's role.

MEMBER WALLIS: The only exception here

that looks significant was the Millstone one. The other ones are sort of little details. But the Millstone one looks more universal, and they got this insulation plaster on the head.

DR. HISER: Would you like me to talk about that one?

MEMBER FORD: Yes, the majority of the members were present at the subcommittee meeting. Let's talk about Millstone, and then we would like at least 5 minutes on South Texas.

DR. HISER: Okay.

MEMBER FORD: And then the rest of the time on the other topics.

DR. HISER: The insulation configuration of Millstone is illustrated here. It looks very nice on mu slide, but not on the screen. Sort of outlined in red is the insulation, and some of it is very closely conforming to the head. We have been told that there is asbestos in parts of the insulation.

In lieu of doing a bare metal visual inspection of any part of the head, the licensees proposed to do thickness measurements from the underhead location to identify wastage in the head.

In addition to, they are performing ultrasonic testing of the nozzles themselves and the leak path evaluation to determine if there is leakage through the nozzles.

So that is their proposal. We have ongoing discussions with --

MEMBER WALLIS: Measuring the thickness of the head is way down the road after the barn door is open and the horses are gone. So how far away did it go.

DR. HISER: Well, there are two parts. Degradation of the head can occur from born that comes from inside the head. For example, through a nozzle leak or from sources above.

The order requires that they determine any sources from above the head. If the UT is sufficient to demonstrate that there is no leakage, then it may be that there is no source of boron that could cause that wastage.

The concern that we have with not doing any visual inspection, there is some complimentary role of the non-visual NDE in providing some assurance of no leakage, and the bare metal visual is sort of a check on that.

First of all, if you look at the intersection of the nozzle and the head, and you see no deposits, and the UT also indicates that there is no leakage, then you have reinforced your view of things.

The bare metal visual provides that assurance, and it also provides assurance that between nozzles that there is no head wastage. So the challenge for us and for the licensee is to determine if their proposed alternative is sufficient to cover th various purposes of the bare metal visual that they would not be performing in this case.

We are aware at this point of one other plant that has a similar configuration and will be making a similar proposal or request to us for relaxation.

They will be very challenging.

Since issuance of the order there are about nine high susceptibility plants that have outages this spring. As indicated, two of those have just started their outage, Surrey and Cook, and so we don't have findings for them at this point.

As indicated, Oconee 3 and North Anna 1 have identified probable leaks in the plant on the upper head. In both cases the heads will be replaced, or have been replaced by the licensee.

So the licensee does not plan to do any additional NDE on the heads to identify the source of the cracks, or the source of the leakage. And in addition our understanding at this point is that Oconee-3 did a comprehensive bare metal inspection.

North Anna, because of their insulation configuration, focused on one nozzle that was at issue at their prior outage. At this refueling, they did identify a probable leak at that nozzle.

The good findings are indicated by Turkey Point Unit 3, Farley, and Calvert Cliffs-2, where they identified no leaks and no cracks, in spite of the fact of a fairly high EDY level in those cases.

Beaver Valley Unit 1 did identify four nozzles with cracks from the NDE, and did repair those nozzles. More recently, St. Lucie 2 has identified two nozzles with cracks, and plans to repair those nozzles.

For plants that are below 12 EDY, you know, in the moderate to low susceptibility range, no leaks and no cracks have been identified.

MEMBER LEITCH: Oconee Number 3, the old head, the head that is being retired. I believe that they found indications of leakage on two nozzles there, one in a previously repaired nozzle, and do we understand what went wrong there with the previous repair?

MR. BARRETT: Excuse me, Allen. We were notified this morning by the licensee that they were mistaken, and that there is in fact no leakage in that repaired nozzle. That is something that we just heard this morning.

MEMBER LEITCH: Okay. Thank you.

MR. BARRETT: Allen didn't even know that.

DR. HISER: It is very preliminary information and that would have been my only further comment.

DR. HISER: The other finding this spring was in the South Texas project, Unit 1. This licensee did bare metal visual on both the upper head and the lower head.

The good news was that the lower head was clean, and no boron, and no indications of leakage. However, on the lower head the visual inspection identified two nozzles with whitish deposits.

At nozzle number one, the deposit was described as gummy in texture, and at nozzle 46, it was indicated that the deposit was hard, and maybe a little more consistent with the findings --

MEMBER WALLIS: Does gummy mean wet?

DR. HISER: I am not sure what gummy means. There has been some speculation. I think it may be related to tape residue and things like that. Their chemical analysis indicated that there is boron in that area, and the licensee is treating it as a possible leakage.

MEMBER SIEBER: What steps are being taken at South Texas to characterize the indication in leak to either say that it is similar to an upper head leak or different than an upper head leak?

And the reason why I would ask the question is that if it is determined to be similar to, and since the lower head operates maybe 50 degrees lower temperature than the upper head, then that calls into question the validity of the ranking system that we are now using, and perhaps you could address that.

DR. HISER: My understanding is that they intend to implement ultrasonic testing to identify flaws in the nozzles or considering ways to examine the J-groove weld in addition. At this point, no plant in the United States has done non-visual NDE on the lower head. There has been no implementation of UT or any current, and so this would be a first of a kind in the United States. There have been some examinations overseas and I think that some of that technology is trying to be applied here.

MEMBER SIEBER: Well, the implication of

my question is characterization leaves to defining the mechanism.

DR. HISER: Right.

MEMBER SIEBER: And you need to know what the mechanism is to either say it is the same as upper head cracks or it is different than upper head cracks.

And if you say it is the same, then you have to question the curve that you are using to identify high susceptibility plants. I mean, it really in my mind at least puts a hooker in the whole way that we are approaching and identifying what plants ought to do what at what time.

And so I think that if we really need to understand what happened at South Texas in a big way, and different than understanding what is happening in the upper heads.

MR. MITCHELL: If I may, this is Matthew Mitchell, Materials and Chemical Engineering Branch, NRR. As of a public meeting that we had with South Texas last Thursday, they provided the staff with a great deal of information regarding their plans moving forward for non-destructive evaluation of the lower heads, and just to reinforce what Allen said, they are looking into doing ultrasonic and any current examinations from the interior of the penetrations.

They are looking into doing enhanced VT-1 examinations of the J-groove weld region, and for those of you who are familiar -- I think the committee is familiar with the term "enhanced VT-1" and essentially a half-mill wire resolution type visual exam of the J-groove weld.

They are committed to performing a root cause and extended condition evaluation, and considering both the implications not only for unit one, but for unit two.

The NRC, and the Materials Chemical Engineering Branch, has been in contact with the industry as well through the MRP. They are working with South Texas to try to help garner as much information as possible from the condition at South Texas Unit 1 to help everyone understand the generic or potential generic implications of what is going on at South Texas.

I would just caution, however that it is at this point too early to fully tell what is going on at South Texas. We are still awaiting results of the NDE and the root cause evaluation.

MEMBER SIEBER: I can see all of that, and I think that is about as much as you can do at this point in time. On the other hand, I hope you recognize my concern that this is a new finding, and different conditions that calls into question the conclusion that we drew earlier on the upper head.

And I guess I can say no more than that because none of us really knows what the mechanism is, and the flaws aren't fully characterized yet.

MR. MITCHELL: Absolutely, and the staff is very sensitive to those observations, including potential differences I think which have already been mentioned in residual stresses, and material properties of the lower head materials, and how they were fabricated.

All of those factors need to be taken into account in terms of understanding what this potential information coming out of South Texas means relative to any other penetrations within the reactor coolant pressure boundary.

MEMBER KRESS: Yes, and given those considerations, I wouldn't get too hung up myself on placing into question the susceptibility curve for the upper head if you could use that curve as a susceptibility curve for the upper, and maybe there is another one for the lower head.

And I like the thought that Texas may be the leading indicator for it, but I wouldn't go too far in saying, well, my curve is just no good because this might be intergrandular stress corrosion cracking. There is different conditions down there.

MEMBER SIEBER: And your point is well taken, but that is why you need to know what the mechanism is, because that will tell you whether you need another curve or not.

MEMBER KRESS: With that intergrandular and stress corrosion cracking, you may need another susceptibility curve for the lower head.

MEMBER SIEBER: Yes, that is a given.

DR. HISER: Well, the experience that we have on the upper head, even some plants have -- some of the BNW plants have thermalcouple nozzle. Now, normal CRDM, with about a 4-inch outside diameter, and the thermalcouples were about 1-inch.

The prevalence of cracking in the thermalcouples was much higher than the CRDMs, and so it may be that their size differences and fabrication differences from the top and the bottom, there are a lot of factors like that that really need to be considered as well.

And that will occur once we know where the cracks were. Are they in the nozzle base material, or the welds, or are they fabrication related possibly, and some sort of fatigue mechanism, or are they a PWSCC phenomena.

Now as I think has been mentioned, the EDY is much lower on this lower head, about 2.1, versus the 20 -- for example, at the Oconee units are much lower than the cutoff for high susceptibility within the order.

So the potential implications are clear from this; we need more information out. The only thing that we really know is that they found two deposits that have boron.

They have been dated through isotopic analysis at about four years old, or I think 1-to-4 years old. Very small deposits. We just need information now. We are aware of the cracks and the source of them.

MEMBER KRESS: When you say 1-to-4 years, I mean, why isn't it just four? Why is there a range?

MR. MITCHELL: Let me clarify that. Based upon again what we received last Thursday, the licensee was concluding that they were 4 years, plus or minus 6 months, in terms of age. So they have narrowed it essentially to approximately 3-1/2 to 4-1/2 year type range.

MEMBER KRESS: Is it cesium dated? Is it

cesium isotopes?

MR. MITCHELL: We didn't get that specific, in terms of exactly what their isotopic analysis was. They did mention that they looked at the cobalt isotopes, and so to be able to disregard it being less than a year old, and they have done the other isotopic analysis to get them to this 4 year type range.

MEMBER KRESS: And this is probably such a small amount of cesium in there that that gives you that uncertainly range.

MEMBER FORD: Allen, could I suggest, unless my colleagues don't agree, that you just go into the last two slides, please. The outlook, and then the final one.

DR. HISER: Yes, the other photographs and slides were presented at the subcommittee, and they are available at the NRC website. Now, overall on the upper head now, the goal is permanent requirements for inspections to ensure structural integrity of the head and the nozzles.

The ASME code is working to develop these requirements. At the present time the industry or the ASME code work is based on an industry report. The staff has provided comments to the industry on this report. In summary, it is not acceptable has it has been submitted, and it is not clear if it will become acceptable.

We have suspended our review pending revisions by the industry based on some of the findings from the fall, and now probably some of the findings of spring.

We expect that report to be submitted in the late summer to us. The ASME code adoption requirements may not be complete until 2004 or later. I thin that is sort of the bottom line on the ASME code activities.

We will implement inspection requirements in 50.55a. This would either be an endorsement of ASME code requirements if acceptable under an implemented and expedited implementation, or we would codify alternative inspection requirements in 50.55a.

Once acceptable requirements are identified, this again would take another one to two years before they would be effective for plants. Some of the items here are items that the industry is providing additional work. One is to complete development of and submit the revised MRP-75 report.

We are continuing to work with the industry on the underlying analyses, and much has been talked about that would support any inspection requirements.

The industry is continuing to develop and improve inspection tools to provide for more effective examinations, and the industry is continuing to look at RPD heads removed from service.

And in particular they have a lot of activity with North Anna Unit 2, and possibly with some of the Oconee heads. The industry does have, as the subcommittee heard, a boric acid corrosion research program to determine the conditions that can lead to accelerated corrosion, and in addition I believe we have recently issued a letter to NEI requesting that they pick up their work on other RCS areas that may be susceptible to cracking.

And other areas that Alloy-600 has used in the RCS.

MEMBER WALLIS: So accelerated corrosion rates, and you simply want to do research to figure out what the corrosion rates are?

DR. HISER: Well, what we want to do is have a basis for the inspection requirements again.

MEMBER WALLIS: When will they be high enough for you to worry about, because accelerated doesn't really mean anything.

DR. HISER: Well, we want to understand the types of conditions that can occur --

MEMBER WALLIS: What is the momentum equation for corrosion.

MEMBER FORD: Could I just ask you to spend one or less than one minute addressing the question of the cracking of Alloy 52 in repair welds and what that situation is?

DR. HISER: The repaired nozzle that was identified as cracked at ANO Unit 1 was a localized partial cover repair, and so the repair left the original Alloy-182 weld exposed. The cracking that was identified was along the periphery, or the interface of the repair weld and the original weld.

And that kind of approach I do not believe has been used in any other plant at this point. The current approach is to entirely cover the original weld material with the 52-152.

MEMBER FORD: And is that the plant where they are doing a destruct examination to determine specific failure modes?

DR. HISER: No, that is still in service. What the licensee did was to implement a repair of that nozzle and then they have restarted.

MEMBER FORD: Thank you very much, Allen.

I would now turn to Brendan Moroney and Douglas Kalinouski to talk about the LLTF action plan. I would like to finish this segment at 10 o'clock to allow some good questioning time on the research program.

MR. MORONEY: We will certainly do our best to accommodate you there, sir. Good morning. I am Brendan Moroney, and I am with the NRR, Division of Licensing Project Management. And this is Doug Kalinouski in Research.

We are here to talk about the action plans that were developed to address the Davis-Besse lessons learned task force recommendations. The recommendations were provided, and they were reviewed by a senior management committee.

And then the EDO tasked the directors of NRR and Research to develop and implement the plan to accomplish this. This plan was completed and delivered to the EDO at the end of February, and subsequently forwarded on to the Commission.

The plan included four action plans to address what were identified as the high priority items in the senior management review team report. The four plans are addressing stress corrosion cracking, operating experience, inspection assessment, and project management issues, and barrier integrity.

And each of them has a lead in one of the offices or departments within the agency.

MEMBER WALLIS: I presume that these are all interrelated, and is someone doing that and seeing how they fit together?

MR. MORONEY: I'm sorry, sir?

MEMBER WALLIS: It seems to me that all these plans are interrelated. Stress corrosion cracking is interrelated to barrier integrity and everything else, and operating experience feeds into it, and so they are not independent. Someone is in charge of the whole work.

MR. MORONEY: Yes, there is an overall coordination plan, and I am in charge of that, but each of the -- the review team that reviewed the lessons learned task force segmented the 49 recommendations into four overriding categories, and each of those then was the subject of one of these plans.

We are going to discuss two of the plans today. One is the stress corrosion cracking activities, and the other one is the barrier integrity plan. I think in a later session today, you are going to be hearing about the operating experience plan.

The stress corrosion cracking plan is divided into three parts basically. The first segment has to do with reactor vessel head inspection requirements. The second has to do with boric acid corrosion control requirements, and the third phase is development or improvement of the inspection program requirements on these activities.

The stress corrosion cracking plan in the inspection requirements for the reactor vessel heads has several steps. One of them would be to develop a database by collecting information from world-wide sources, both foreign and domestic, on Alloy 600, and 690 and other nickel-based alloy, nozzle cracking information, and this would be developed from technical studies, from previous related generic communications, industry guidance, and operating experience.

The second phase would be to evaluate the existing stress corrosion cracking models used in the susceptibility index, and take into consideration the large uncertainties and determine whether additional analysis or testing are needed to reduce these uncertainties.

MEMBER FORD: Now, I noticed in the actual plan that was distributed at the last meeting that it says medium, and does that mean medium priority?

MR. MORONEY: Okay. There were medium and low priority items identified. There were some of those medium and lows that we felt were so closely related to the high priority items should be done in conjunction with them, that we did incorporate probably about half-a-dozen of those lows and mediums into the various action plans.

So the action plans are specifically designed to address the high priority items, but we did bring some of the lows and medium priority items into the action plans.

So that particular item might have been identified as a medium, but it was considered important to be --

MEMBER FORD: So not treated to high because it is in this plant. Okay.

MR. MORONEY: Yes. The third phase would be to evaluate the results of the inspections that are being done according to the bulletins in the order. The first complete cycle of all of the outages of the various plants will be completed in May of next year or the spring of next year.

So that is the reason for that implementation date there or target date there.

Another phase would be to evaluate the MRP and ASME efforts, and Allen Heiser I think just went into some detail on what that effort entails.

We don't have specific data identified yet because we are still waiting for the revised submittal of the MRP 75 guidelines, but those dates will be targeted once we do have that in-house.

The ultimate goal is to establish permanent guidelines which would be codified most likely through an update of the 10 CFR 50.55a requirements, and we would be looking at what the ASME code requirements suggestions come out and decide whether or not those are to be endorsed, or to go ahead with a different set of requirements of our own.

The second phase of the action plan has to do with the boric acid corrosion control programs. Once again, one of the initial efforts in this particular activity is the collection of a database of information similar to what we are talking about for the cracking concern.

The second would be to complete the evaluations of the responses that were received in response to Bulletin 2002-01. That initial evaluation has been completed, and the technical staff is discussing its findings and recommendations with their management at this time.

And based on their review and those discussions, the need for any additional regulatory action will be identified, and we are targeting the end of this month to have this going forward, and it is being worked on right now.

Any additional activities and milestones will be added to the plan as soon as that has been determined. The ASME is also doing some code work to address boric acid corrosion, and we will be looking at those and reviewing and evaluating those activities as they become --

MEMBER WALLIS: Well, this is very high level, and you have all these plans, but is there anything which has resulted from number two which is of interest to this committee since you have done it? Is there anything that has happened --

MR. MORONEY: Well, like I said, the tech staff review has completed their initial evaluation, and I think the report right now is in draft form, and it is still preliminary and being reviewed by management.

MEMBER POWERS: I am at a loss to understand what exactly was accomplished. The boric acid corrosion I presume is a bad idea. What are they evaluating?

MR. MORONEY: They are evaluating the programs that the licensees have in place, primarily to respond to generic letter 80.05, which identified certain aspects of having a program for inspecting, identifying, and following up on indicated leakage. of the boric acid in components.

MEMBER FORD: Surely in relation to what Dr. Powers is saying, in the 2002-01 responses, the initial response was that there is not another Davis-Besse out there. There is not another plant which is corroding by boric acid corrosion at one inch per year, which is comforting.

But the underlying question behind Dr. Powers' concern is given that, why not or why is it that, or do we understand why there are not other plants out there corroding at one inch per year.

What are the physical phenomena, fit gaps, whatever it might be, that tells you that that particular nozzle corroded at one inch per year undetected or whatever, but it doesn't matter. The adjacent nozzle was not. Why? Until you can answer that question, you cannot just sit back and say no more problem.

And what I was hoping to see in this

particular subset, in part two, in the boric acid control, that is what you are driving at? At the end of the day, by 1:05 or whenever the day is, you can answer that question? Is that correct?

MEMBER POWERS: Well, you are hitting into one of many points that comes from this. I mean, do we have a sufficient understanding now to say this kind of configuration is no good, and that other kind of configuration is just great.

MEMBER FORD: And can you measure that? I mean, do you understand why that nozzle is --

MEMBER POWERS: And this looks like a scholarly work going on, but it hardly looks like research work going on.

MR. BARRETT: Let me say a word about the bulletin, and this is Richard Barrett with the staff. The evaluation of the Bulletin 2002-01 responses was actually a separate part of Bulletin 2002-01 that was not related to the head degradation itself.

It was a question that regarded the rest of the reactor coolant system, primary coolant system, and what was being done out there. And the responses that we got, this was a 60 day request. We got the responses, and they did not contain a level of detail sufficient for us to evaluate licensee programs.

So we put out a request for additional information, and we have gotten the responses, and we have evaluated them, and we have sent a team out to do three audits of three separate utilities just to see and get a little better view of what their procedures are.

And we now understand what is being done. This is not an effort to understand the basic science behind corrosion. It is really to look at what is being done with regard to the inspection of the rest of the reactor coolant system, including the bottom head.

And we now fully understand that, and we are in the process of deciding what if any additional regulatory requirements we want to place on the rest of the reactor coolant system specifically for those locations where we have these nickel-based alloys interfacing with the reactor coolant system.

And right now that is a very heavy activity we have going on, and as that ripens, we will certainly want to come and talk to you about it.

MEMBER POWERS: I think I am supposed to derive what you just said from this view graph?

MR. BARRETT: Well, this is a status briefing, you know, and I think we would certainly be happy to provide more detail of --

MEMBER POWERS: Well, what are you trying to accomplish with this, and where do you want to be that you are not now that I am missing from this?

MR. BARRETT: With respect to the reactor coolant system, we know a few things. One is that we have some operational experience. We have the summer cracking, through wall cracking. We have or we now have South Texas, which we don't fully understand.

I think there is reason to believe that the operational experience is not as dire as it is for the upper head. Nevertheless, we don't want to be in the position that we got into with the upper head, where we were trying to catch up.

We had a surprise, and we tried -- and we had another response, and we tried to respond to it. The idea here is to say what can we do to get out ahead of that knowing that these plants are aging, and knowing that these phenomena are out there.

What do we want to do in terms of getting ahead of that, in terms of new requirements possibly, new rules, or other regulatory vehicles. That is what we are trying to accomplish.

MEMBER WALLIS: But you may find that you don't get ahead of the game with what you have been doing here.

MR. BARRETT: That is very possible. This was all initiated and this is on its tract long before we found out about South Texas. We don't fully understand South Texas, but we may have to adjust our plans based on what we have learned at South Texas.

MEMBER WALLIS: Okay.

MR. MORONEY: The third part of the SCC action plan is to develop new guidance or improve existing guidance for various activities. The first one is related to the review, the periodic review of ISI activities by the licensees.

This is on-site review of the activities that go on during an outage, and it involves monitoring and evaluating those activities as they are in progress, and follow-up on any identified issues that are resolved and reports that are generated.

Currently to track the bulletins, we do have a temporary instruction issued to the inspectors to follow up on the bulletin activities. The intent is to provide permanent guidance in the future, and that is targeted for early next year.

The second issue has to do with providing guidance for the inspection of boric acid control programs at the licensee sites. Currently there is no specific guidance within our oversight program that specifically talks about boric acid control inspections.

The Davis-Besse task force identified the fact that the previous guidance was somewhat discretionary and it was associated with corrective action program follow-up, problem and identification, and corrective action program follow-up.

So the intent once we have completed or substantially completed the activities in the Phase II activities on the boric acid and corrosion control program would be to provide detailed guidance for inspection and follow-up.

And part of that or associated with that would be what to look for in evaluating boric acid control programs; implementation effectiveness at the sites, and the ability and the processes for identification of leakage, and the process for adequate follow-up on identified leakage.

MEMBER POWERS: But this guidance -- is the function here is to communicate to the inspection staff the things that experts within the agency and elsewhere have on these corrosion issues as of today?

MR. MORONEY: Or ongoing in the future, too. These things --

MEMBER POWERS: Well, you can't be too far away. It is only March of 2004.

MR. MORONEY: Yes, sir.

MEMBER POWERS: Okay. It is an information transfer function, and there is nothing new being discovered here?

MR. MORONEY: Not in these. These are the results from the other activities primarily.

MEMBER FORD: In other words, you are going to be giving guidance of the expectations for the licensees ISI program as to when, how often, and by what technique they should be inspecting, and the expectation of probabilities, and all of these inspection technical details?

MR. MORONEY: Yes, that would be part of the development of whatever regulations we ultimately come up with, or the inspection. The inspection guidelines are instructions to our inspectors to follow up and go out, and then when they are doing their on-site inspections, what to look for and what to follow up on.

MEMBER FORD: Okay.

MEMBER LEITCH: I am a little confused. Inspectors must now have guidance as to what to look for in the licensee boric acid corrosion control?

MR. MORONEY: Not specifically.

MEMBER LEITCH: Not specifically?

MR. MORONEY: No, sir.

MEMBER LEITCH: Okay. I would have thought that there would have, because that is a generic letter 15 years old, right?

MR. MORONEY: Yes. There was at one time a set of instructions, which I believe that is no longer effective after the conversion over to the new ROP program. And this action would be to come up with new guidance.

MEMBER LEITCH: That is very interesting. It opens up a broader subject to me that we won't pursue right now, but I am just wondering are there other things, inspections that were routinely conducted that are no longer conducted because we are in an ROP program?

MR. MORONEY: I believe that is a true statement.

MEMBER LEITCH: Okay. Well, we will need to pursue that at another time. I was not fully aware of that.

MEMBER FORD: Could we spent just 10 minutes at the very most on this particular item.

MR. KALINOUSKI: It shouldn't take that

long.

MEMBER FORD: Okay. Thank you.

MR. KALINOUSKI: Okay. My name is Doug Kalinouski, and I am with Research, Fuel Engineering Branch. I will go over the Barrier Integrity Action Plan. Right now it is broken down into two parts. The first one is leakage detection and monitoring requirements, and the second is improved performance indicators.

All right. The first part is we will begin with the review of the plant tech specs to identify their leakage requirements, and also identify the plant alarm response procedures for leakage monitoring systems. Based on those two, and in conjunction with, we will develop a basis for a new reactor coolant system leakage requirements is the first high priority task.

And it consists of a review of the current leakage basis, and we want to look back and see how they came up with the current requirements basically, and see if it is appropriate still, or how or what we can improve upon what.

We also review the experience capabilities of the currently used leakage detection systems, and we want to particularly find out how accurate they are, an how sensitive they are, and how reliable they are.

And based on that, we also review or evaluate the capabilities of the state-of-the-art, or more up to date systems that may or may not be in use. This includes foreign, as well as domestic, plants. We also expanded the scope of the actual plan to include detecting degradation in addition to just leakage.

And the idea here was that some cracks, like SSC cracks would be so tight that they might not be leaking very much and detectable. And finally the last bullet there is evaluate leak rates -- it should say arising from degradation, as in leak rates from cracks in the various components in the RCS.

Now, based on those items in the first slide, the next major section is to develop recommendations for improved leakage requirements. Now these can include and won't be limited to tech spec changes, and make standardized tech specs throughout the plants, improved inspection guidance dealing with unidentified leakage.

And possibly updating Reg Guide 1.45, leakage detection systems. And then based on the recommendations, they will be evaluated, and if they are appropriate, they will be changed into requirements.

And the last bullet here is to examine other improvements that won't rely just on leakage monitoring. Again, this goes to the bullet of the degradation, and try to get some kind of on-line degradation system if we can to monitor or improve inspection to catch the degradation before it becomes a leak. And to ensure barrier integrity.

And the second part of the plan is to performance indicators. The first being implement improved performance indicators based on current requirements and capabilities, and look at what they have now.

This is all currently being worked on by NRR, and they are trying to improve it based on total leakage, including unidentified and primary to secondary leakage.

This is basically to develop more robust performance indicators. Based on our part one, we hope to develop advanced performance indicators, and this was a recommendation in the lessons learned task force that they would like to possibly track a number duration and rate of primary system leaks.

And we will take a look at that and see if it is feasible, and if so, try to implement some kind of performance indicator based on that. And the last --

MEMBER LEITCH: I am having trouble understanding what we are really discussing here. Total leakage identified or unidentified. It seems to me that in order to -- I mean, the kind of leaks that we are talking about here are very, very small.

And by the classical means of just knowing what is the total leakage for the identified versus the unidentified leakage, the kind of leaks that are talking about here would be lost in the noise.

You know, you could have a little valve packing drip here or there. It is going to be very difficult to measure these kinds of leakage by classical methods.

Now, are you talking about some different kind of method perhaps for detecting leakage above the head, for example, rather than just the total system leakage? I just don't quite understand how we are going to get anything of significance other than just noise data here. These leaks are so small.

MR. KALINOUSKI: That's right. One idea is to try and separate out the leakage based from pumps and seals if you can collect it separately, so that you can count more accurately.

But like you said, this is the -- if you look at its feasibility, and you're right, and it might not be feasible to do stuff that accurate based on the systems that we have.

And right now it is very up in the air on which way we will go with it. If we can do it, we will try, and we will take a look at it and see if we can be more accurate. But like you were saying, there are small amounts and it is hard to do.

MEMBER LEITCH: Well, I was just wondering if there is a totally different concept that you have in mind? That is, perhaps some way to measure or identify leakage in the upper head area, or is that part of this thinking?

MEMBER APOSTOLAKIS: The thrust of your question, Graham, is that knowing that there is a leakage doesn't really tell you very much. You would like to see more geographical dispersion and information where it is.

MEMBER LEITCH: Exactly.

MEMBER APOSTOLAKIS: Or otherwise you just have data that by and large would be useless.

MEMBER LEITCH: Right.

MEMBER APOSTOLAKIS: Okay.

MR. KALINOUSKI: And it would change it from unidentified to identified leakage at that point is what you are saying.

MEMBER APOSTOLAKIS: Yes.

MR. KALINOUSKI: And I have no answer for that.

MR. CHAN: I guess there are some things to recognize. Some plants do have supplemental leak collection systems.

MR. KALINOUSKI: Right.

MEMBER SIEBER: They are expensive to build because they have a lot of catch basins, and they have a tendency to plug up with age because generally here is no flow in them.

On the other hand in the Davis-Besse situation, if you looked at those graphs that they had, which they should have been plotting every day, because that is a generally accepted practice, you can actually see the start of the leak on the head there.

It's just that as several have stated, that you don't know where it is. It is a leak in the plant someplace. It could be an intersystem valve, and it could be packing, and it could be a pump leak. It could be anything.

On the other hand, usually when you see a change in the RCS leak rate, that alerts people to start looking and make a trip into containment to generally look around, and where you may have television or other ways to do this.

One thing that should not be ignored is the fact that there acoustic systems out there that not only can tell you that you have got changed leakage, but that it can tell you roughly where it is.

And they are quite elaborate systems, and it takes a lot of transducers to make them work. On the other hand, they do work, and they have been used.

I am not sure what the sensitivity of them is, but some folks tell me that they are pretty sensitive. And they are used frequently for hydrostatic tests.

MEMBER APOSTOLAKIS: Could you give me an example of an advanced PI that would have caught Davis-Besse?

MR. KALINOUSKI: I can't, no.

MEMBER APOSTOLAKIS: Now, the PIs will be used in the oversight process, the reactor oversight process?

MR. KALINOUSKI: Yes.

MEMBER APOSTOLAKIS: So let's say the PI goes from green to yellow, as I recall the action matrix requires a conference between the licensee and the NRC staff, and the licensee will propose a course of action on what to do, and the staff will look over their shoulder. I mean, that level of interaction.

Now, if they during that conference they dismiss the significance of what they see, how good is the PI? What good is it? I mean, they interpret the findings in a way that is -- well, it is not a big deal. But then what?

MR. BARRETT: Let me -- this is Rich Barrett, with the staff. If a drip indicator, and this indicator as you recall, we have seven cornerstones, and this indicator would be in the barrier integrity cornerstone, I presume.

If you had a non-green, and say in your case a yellow finding, that would go into the process, and if you had a licensee that had -- and coincidentally a yellow finding in mitigating systems, and a white finding someplace else in initiating events, that would trigger further actions.

So without going into a great deal of detail about the action matrix, which I have not looked at in quite some time, that would be the significance of it.

MEMBER APOSTOLAKIS: Well, I guess the

point that I am trying to make clear in my mind us what is it in this new structure that would make people go look at the vessel head that there is a leak of boric acid, versus what they actually did?

I mean, by declaring something a performance indicator, and something happens that didn't happen before, you still have to interpret it don't you?

MR. BARRETT: I think -- I am not sure.

MEMBER APOSTOLAKIS: Or you have to bring it back to green, and that is probably what would be the action. Somehow you have to bring it back to green.

MR. BARRETT: Again, this action plan is -- we are moving into areas where we have some possibility that these investigations may not be successful, and that we may not be able to make improvements, but the oversight process is -- I don't think we depend on the oversight process, and the use of performance indicators, and the assessment of yellow and white findings, and all that.

I don't know that we want to depend on that to find problems in the plant, such as the Davis-Besse problem. I think we would want this kind of activity to look for or to be an aid in looking at more systemic problems in the organization of the plant, and overall performance problems that could be remedied over time.

I don't know that we would want to use a performance indicator to find or to preclude, let's say, another Davis Bessie. We would want to have other things do that.

MEMBER APOSTOLAKIS: I thought that was the whole idea of the oversight process, to do just that.

MEMBER FORD: Could I just make a suggestion, George? I think maybe this particular topic can come up in the next talks, which will be in Jack's area, because I have got a time crunch here. I have to finish at 25 to, and we have one more presentation.

MEMBER APOSTOLAKIS: What is in Jack's area?

MEMBER FORD: Pardon?

MEMBER SIEBER: On 3 of the 4 task forces, and one is this afternoon, which is operating experience.

MEMBER APOSTOLAKIS: Okay.

MEMBER FORD: So thank you very much indeed. I am sorry that we have pushed you, but I would like to ask Bill Cullen to come and give the final one.

MEMBER APOSTOLAKIS: If you call that pushed, I don't know.

MEMBER SIEBER: While everybody is changing places, I would like to address a little bit of George's question. The problem from a regulator standpoint is that you have to set a threshold for performance indicator in order to be able to have a basis for doing something with the licensee.

The issue is setting the threshold, because there are so many things that can occur in RCS leakage that that threshold is certainly not a definite sure thing. It becomes just an invitation just to start an argument about what it is, and what you are going to do about it.

So I think that there is a true challenge in coming up with a performance indicator that has more.

MEMBER FORD: Bill. I have asked Bill to concentrate just on Items 1 and 2, and to not discuss 3. All of these items were discussed at the subcommittee meeting.

Bill, we have heard some of the questions so far today on both the nickel-base alloy cracking and the boric acid corrosion to some of our concerns. So if you could -- and I apologize for the timing, and if you could try and concentrate on addressing those.

MR. CULLEN: Thank you. I will. For the record, I am Bill Cullen, from the Materials Engineering Branch of the NRC's Office of Research. As Peter indicated, there is a few topics to be talked about today. I wanted to go over very briefly the currently funded NRC Office of Research Programs dealing with the issues that we have on the agenda today. I will point out a little bit about some other programs that are going on elsewhere in the world that feed into these areas of interest.

And talk a little bit about where I think we can go with some of the materials that are available from the discarded heads here in the United States, and a little bit about stress analysis of CRDM penetrations.

That issue was raised this morning with respect to the South Texas issue, versus or as compared to the head issue, and I will delete or have in this presentation a little bit on what the exposed clad analysis does mean to this industry.

Okay. We do have programs currently ongoing, and some of them have been going for 5 or 6 years to do stress corrosion cracking growth rate measurements on nickel-based alloys that are of interest in this vessel head penetration and bottom mounted instrumentation penetrations.

There are some reports that are currently out and currently available, and have been available for some time. And other reports that are coming available in the reasonably short term.

Most of this information is from our program at Argonne National Laboratory, and Dr. Shack, a member of the committee, is of course the head of that group that is working on these sorts of things. There are reports out dealing with the results on Alloy-600, which that work does continue.

But there is also work on Alloy-182 under way that will be reported out late next year. I also want to point out that we have salvaged materials from the Davis-Besse reactor head, and those materials are at Argonne right at the moment.

They are being turned into specimens for testing of both the Alloy-600 from nozzle 3, and the Alloy-182 for nozzle 11, which was next door to nozzle 3. Those materials will go into the test program about mid-summer, and I expect that we will have results by the early fall, stress corrosion growth rates on those materials.

Also, you have heard just ahead of this presentation the information from the LLTF, and so we don't need to go through that again. Also, I want to point out that all of us, we as a collective group, are going to be getting a good more data from other agencies, from other countries, that will feed into this program.

And I think will be very, very helpful in our overall understanding of Alloy-600, and Alloy-182, and 690, and 152, and the microstructural effects that result in the -- you might call it the dispersion of crack growth rates. I am going to touch on that a little more later on.

But I want to point out particularly that there are two very, very large programs currently ongoing in Japan, and those results will be fed out in due time, but they will be providing a lot of data on these alloys of interest, including Alloys 690 and 152.

Quite frankly, here in the United States we are not currently doing that much work to trying to determine the crack growth rates of Alloys-690 or 152, the alloys of interest for both repair and for the replacement heads.

MEMBER POWERS: When you say we, who is we? Is that the Nation as a whole, or --

MR. CULLEN: Yes. That is exactly what I meant. Neither the industry nor the Office of Research at the present time are engaged in any significant amount of work.

Now, we do have that in our Office of Research program, but that work will not be starting up until either late this year or more likely next year, when we sort of finish with the matrices on Alloys 600 and 152, and we obtain materials of reasonable interest on Alloys 600 and 190, and 152 materials of interest.

So we do have that in our programming, and it has not started yet, and I am not aware of any industry work in 690. Well, I shouldn't quite say that. There is a little bit going on at Westinghouse, but there is no data that is coming out. They cannot get cracks to grow in the stuff fundamentally.

So I am going to stick with my comment and say that I a not aware of any data, any useful data. All right. As it turns out, next week there is a meeting of this group on the ICGEAC, the International Cooperative Group on Environmentally Assisted Cracking up in Ottawa.

That group is currently engaged in a round-robin. I expect to see some of the first crack growth rate data on Alloy-600 to be presented at that meeting.

Also as part of that same round-robin, we will be going on and doing some testing in Alloy-182, and our contractor, again Argonne Labs, is participating in this round-robin, and will be generating data, along with a wide spectrum of other laboratories around the world,

You can see what the expectations are for that, and collecting the info meant collecting the information on how these tests are to be conducted in coming up with a test plan, or a set of specifications for doing the tests that was agreeable to all and would produce the kind of data in which we have the interest that we need to have.

MEMBER POWERS: Is there a comparable activity around the world on Alloy-800?

MR. CULLEN: No, there is not. As far as I know the use of Alloy-800 is confined to a handful of European countries, and largely as far as I know and somebody tell me if I am wrong, most as steam generator tubing.

I am not aware of much use of Alloy 800 in thick sections. If anyone knows differently, please offer that assistance, but I am not aware of that.

MEMBER POWERS: Well, steam generator tubing, of course, is of substantial interest in and of itself.

MR. CULLEN: Of course.

MEMBER POWERS: And I just wonder why. I am asking you to dissect the material.

MR. CULLEN: That is a little bit out of the scope of my basic knowledge at the moment, but I understand your question and I will do what I can to get you a reasonable answer to that.

MEMBER POWERS: I would appreciate it. That would be of interest.

MR. CULLEN: Okay. I will do that. Also just to note that we are working with the industry and with the licensees to obtain some of the materials of the heads that are coming off these reactors to be replaced.

And we are making very good progress along that line. We have some of the materials from Davis-Besse, and we are going to get some of the materials from North Anna, and there are other discarded heads that are under discussion at the present time.

Okay. What can we do with the materials

from the discarded heads? This is an example as it turns out, listing the heats that were in the David-Bessie reactor over here on the right-hand side.

These are the heats of Alloy-600 that were in the head of the Davis-Besse reactor, and the other plants in which these same heats of material are currently found.

Now, as it turns out, since I put this slide together most of these heads over here are going to be replaced or are scheduled for replacement somewhat soon. So it is almost a moot point as to whether or not we could really use any of these materials to assist with flaw evaluation of a crack that might or might not be found in one of these other heads.

The point is that it is a moot point. However, in the next slide, it is a slightly different situation with the materials that are in the North Anna head. Here are all of the heats of the Alloy-600 that were found in the North Anna head. The North Anna-2 head, several different heats.

And the cross-correlation with where they are found elsewhere. Again as you know, North Anna 1 is going to have the head replaced on it, and some of these others as well, but there are plants down here that currently do not have any plans for head replacement.

So conceivably if a licensee chose to do so, and chose to perform a flaw evaluation, they know where they could get the precise heated material that they would need in order to do crack growth rate tests, and to perform that sort of a flaw evaluation.

Whether or not that would be specifically done, that is not really the point that I am trying to make here. The point that I am trying to make is that as these heads come off, we are going to accumulate a kind of inventory of materials that might possibly be very, very useful in flaw evaluation should a licensee choose to do that.

MEMBER SIEBER: It is a fact though that -- I think, and you can tell me yes or no -- that for all the reactor vessel heads that are out there, there are insufficient records to identify the heat for every one of the 5,000 or so nozzles that are there; is that correct?I would like to just refine that very, very slightly.

We do know that for each and every head, we do know what heats of material are in that head. And for at least some heads, we know which heated material are in a specific nozzle. Give me a nozzle number and I can give you the heated material.

I do not know for certain that that is known for all heads of all PWRs in the United States. There is some hearsay evidence that probably the licensees, the individual licensees, do have that specific information.

Also, I have heard some hearsay that in some cases they may not. So I am hope I am refining that slightly. That it is not quite that dismal that we don't know. I mean, we do know in a great many cases.

MEMBER SIEBER: That is my understanding also. Thank you.

MR. CULLEN: I had planned to have a conference on this issue at the end of March, but the geopolitical events of the world served to conspire against that possibility when travel restrictions were placed on a number of attendees to that conference.

We did expect about 140 people to attend. It was going to be March 24th to 26th. There were participants from around the world. We just started talking this week about rescheduling that conference for very late in September.

It looks as of this morning that that might happen, and we will know more about that in a week or so. A little bit on stress analysis, and I am leading up to something here as you might guess.

Remember that the words stress corrosion cracking, we have been dwelling on corrosion as it may apply to materials susceptibility. The other part of that equation, and the other very important part of that equation is stress.

And we do have programs within the Office of Research to put together the finite element models to compute the levels of stress in these nozzle assemblies. And just to review now, all of these finite element programs, whether they are the ones that we are sponsoring in the Office of Research, or in the industry, they all work the same way.

You model the deposition of the welds that are combined to produce the J-weld assembly in a vessel. So you basically in a mathematical or computational sense, you deposit a weld at a very high temperature and you allow that weld bead to solidify, cool, contract, and that contraction provides the stress that we all know about now.

And you would then repeat that process for the number of beads that are normally used to create the total J-weld assembly, and when you are all done, what you get is a stress block that looks something like this, and this is for the hoops stresses that would obtain under normal operating pressures, and normal operating temperature, and you can see that red is bad and green is good.

So the hoop stresses are distributed well throughout the nozzle and throughout the J-weld, and of course it is the hoop stresses that would tend to open an axial crack in an assembly.

And I just wanted to show you an example of how this all works, because this is the hot-button slide that we talked about some this morning. Again, I want to combine the information here with the information on the previous slide about consideration of stress in the susceptibility model, and that is where I am headed with all of this on the next couple of slides.

I would like to make a couple of points about this particular graph, which is taken from the industry's document, MRP-55, which is their evaluation of crack growth rates in Alloy-600 in PWR conditions.

First off, there are very, very good and well understood reasons for why Alloy-600 exhibits such a wide range of crack growth rates under essentially similar conditions, the same PWR conditions.

And the reasons have to do with the microstructure of the material and that relates to the way that the material was heat treated in the first place. There are some very good heat treatments, thermal treatments, of Alloy-600, that render this stuff very, very resistant to crack growth rates, or to crack growth in PWR environments, and presumably these data points at very low crack growth rates are materials that would exhibit if you look at them carefully that kind of resistant microstructure.

MEMBER WALLIS: I am very surprised that quality control is such that you can get this stuff so good. How do you allow it to get so bad?

MR. CULLEN: I think I would share your surprise, but we now know that many of these materials, particularly those that were product in the late 1960s, early 1970s, when the industry was running at full bore, they just did not look at their performance indicators quite as carefully as they might have.

And we now recognize that some of that material got out of the plant, and it was just not optimally produced.

MEMBER WALLIS: But at that time, they knew how to make it better or they were just ignorant?

MR. CULLEN: Well, we certainly have learned something in the last 30 years, but I think even in the 1970s they knew the fundamentals of what should be required.

I mean, we had heat treatment specifications that we do know produce good quality material, and do today if you were to do that today. So your point is well made. Quality control was not as thorough or as careful as it ought to be.

And some of the materials that we see tested here, while not -- and I don't want to give you the impression that all of these are domestic materials. This data was gathered from worldwide sources, and represents that sort of spectrum.

MEMBER WALLIS: is the foreign material better?

MR. CULLEN: No, generally not, and there is a bias in this graph that is impossible to see from this particular approach that kicks things up into the higher range because of the more susceptible non-American materials.

There are susceptible American material. I don't want to give that impression either. Without getting into a lot of details and trying to reprise the discussion that we had about an hour or so ago --

CHAIRMAN BONACA: Just a question. The heat treatment is not sufficient I guess? I mean, people are going to 690 of materials, and I am intrigued by your statement, where you are saying that heat treated materials, Alloy 600, that behave very well and have low susceptibility.

MR. CULLEN: Thee is no question that Alloy 690 is better. Well treated, carefully treated Alloy-600 is darn good. I feel very strongly about that.

Alloy-600 is fundamentally a good material, but it got goofed up along the way.

CHAIRMAN BONACA: All right.

MR. CULLEN: And the other part of the equation -- and I am going to come back to this in a minute, too -- is the assembly of these things, and the J-welding procedures, and that has also improved a heck of a lot over the last 30 years.

And I do believe that at least the replacement head procedures that I am aware of are far better than they were again 30 years ago. Lastly, I just want to point out that we do have a number of programs going on within the Office of Research that we hope will lead to a better model.

We are currently using the susceptibility model, and I will show that in a minute or so. But we hope through some of the efforts of our programs within the Office of Research that we are working towards a model that will be more accurate, more useful, more encompassing, than the current susceptibility model.

And the models that we are working on will attempt to include a wider range of the inputs, including inputs from the inspection, as well as the crack growth rate, the stress analysis, all these sorts of things, we hope we will be able to combine and feed into an improved model for risk analysis.

I also want to point out that because of the worldwide interest in this interest, some of my colleagues in the Office of Research are getting together fostering the development or the assembly of an international cooperative group, which would meet I presume annually or biannually to keep these issues in the forefront, and to gather together the research information from around the world in a more efficient and effective way.

MEMBER APOSTOLAKIS: Now, when you say this analysis model, you don't mean PRAs? PRAs are --

MR. CULLEN: No, this would be a probablistic model used to compute times between inspections that would be optimal on a plant to plant basis in the ideal sense.

So some plants would have to inspect more often if they had susceptible materials, higher stress, less high probability of detection, and so on.

Okay. I would like to talk a little bit also about this susceptibility plot. First of all, what we are looking at here now is a plot of the -- basically the time at temperature for American plants, domestic plants now, ranked from number one, up to 67 or 69. 69, thank you. Now, this plot simply ranks the plants.

The one with the most EDY is down here at the bottom, and what we have plotted here is the EDY as of January of 2003. So just at the beginning of this year. So the EDY for each of the 69 American plants was calculated in January of 2003 based on the best information that we had about the temperatures that they had.

This information is strung or provided to me from the industry by the way, and some of the plants do have multiple data points, where there was an inspection for a plant some years ago at an earlier EDY, and you will see that data point and its results ont he same horizontal line as you will see some of the other data.

So that's why the plot looks a little bit ragged. The point was made in an earlier presentation before the ACRS subcommittee that things just did not really look right, and quite frankly I didn't do a great job of explaining why they didn't look right.

But if you just reduce this to just the one most recent data point in plants, this would be at least a monatomically increase in plot, rather than having the raggedness.

The raggedness is simply due to the fact that some plants had earlier inspections and the results for those earlier inspections are also presented here. Allen made the point this morning very accurately that the rankings do appear to work, and there was some mention made about these boundaries being, quote, somewhat arbitrary.

Well, that may be the case. Pragmatic is certainly a better word than arbitrary, but the point was made this morning that all of the heads that are shown to leak are accurately described or positioned on this graph. They are all in the high susceptibility range.

Now, there are plants that have had cracks that have not leaked that are down here in the medium susceptibility range. But that is not the issue with this particular plot and the coloration of it. We are looking for leakers here, and the boundaries were established to separate low, medium, and high susceptibility with respect to leakage.

MEMBER POWERS: Could you one more time try to explain to me what the vertical axis is?

MR. CULLEN: The vertical axis simply goes from the number 1 to the number 69, and ranks the -- if you just do a simple, straight ahead calculation of the EDY for each American plant.

And then you sort through that from highest to lowest, or lowest to highest, in this particular case. And then just plot the result. So the 10th plant is going to have some EDY, and the 11th plant is going to have something a little less, and the 12th, a little less than that, and all the way up.

MEMBER FORD: William, I apologize, but the Chairman has told me that I have got 3 more minutes.

MR. CULLEN: We are really at the point where --

CHAIRMAN BONACA: I just had a question on that previous curve. Could you go back to the previous curve.

MR. CULLEN: I certainly can.

CHAIRMAN BONACA: That doesn't mean that all the green spots don't all have cracks?

MR. CULLEN: No, the green spots are either green NDEs --

CHAIRMAN BONACA: Well, well you have two triangles there that are red.

MR. CULLEN: And the orange, okay.

CHAIRMAN BONACA: Those were performing ultrasonic testing, and found they had cracks, but no leaks?

MR. CULLEN: I don't know that it was ultrasonic. Maybe some of my colleagues would know, but some detection methodology found a crack that did not leak and the crack was repaired at this particular EDY value.

CHAIRMAN BONACA: My question was how many of those greens may be in the same situation, where there is no -- you know, visually you don't see any leakage, but there may be some cracks?

MR. CULLEN: Well, I think as of today that we really don't know that, but my understanding of the results of the bulletins, and the new inspections is, is that we are going to be able to cover all of these within the next couple of years.

CHAIRMAN BONACA: Okay.

MEMBER FORD: Thank you, Bill. I do apologize for cutting you short, Bill. I would like to thank all the presenters and I hand it back to you, Mario.

CHAIRMAN BONACA: That was fast.

MEMBER FORD: That was a fast 3 minutes.

CHAIRMAN BONACA: Thank you, and any additional questions from the members? I think that Dr. apostolakis is anxious to know. Well, no, let's take a 20 minute recess, and we will get back at 5 of 11:00 for the next presentation.

(Whereupon, at 10:36 a.m., the meeting was recessed and resumed at 10:56 a.m.)

CHAIRMAN BONACA: Okay. We will resume the meeting now, and the next item on the agenda is Proposed Revisions to Regulatory Guide 1.178, and Standard Review Plan Section 3.9.8 for Risk Informed In-Service Inspections of Piping, and Dr. Shack will take us through this presentation

MEMBER SHACK: Okay. Risk-informed inspections have been one of the success stories of risk-informed regulation, and I think that most people would agree that we have been able to focus inspections, which were originally set up by ASME, assuming the fatigue and weldments were the primary cause of failure, and focusing on piping segments that are risk significant and more subject to failure under the realistic set of degradations that we found in the reactor systems.

And we are looking at an update of the Reg Guide 1.178, which essentially provides standards and criteria for the risk-informed inspections.

MR. ALI: Okay. I will start with introducing ourselves. I am Syed Ali from the Office of Research.

MS. KEIM: I am Andrea Keim, from NRR, Division of Engineering.

MR. DINSMORE: Stephen Dinsmore, from NRR, PRA Branch.

MR. ALI: Okay. I am going to start by giving the background of the risk-informed ISI reg guide and SRP, and then Steve will go into the actual changes.

Back in 1996, the PRA implementation plan established a plan to develop a general reg guide, and that was Reg Guide 1.174, and the corresponding Standard Review Plan, and that was Chapter 19, and four application specific for reg guides and standard review plans.

And these four pilot applications were technical specifications, tech spec, IST, graded QA, and ISI. For ISI, that was Reg Guide 1.178, and the Standard Review Plan 3.9.8; and both were the application of risk-informed in-service inspection methodologies to piping.

As Bill has mentioned the application of the risk-informed ISI for individual plants has been one of the most successful applications of the risk-informed pilot applications. We will talk a little later about how many plants have submitted applications and what is the status of the review and all of that.

Quickly going over the background again, most of the U.S. plants are designed and constructed to the ASME boiler and pressure vessel code. The ASME Code inspection locations are typically focused on locations with high mechanical stress, or fatigue usage factors.

The industry experience has been that flaws have not been typically found at such locations, but rather at locations with specific degradation mechanisms. Next slide, please.

The purpose of in-service inspection very quickly is to of course prevent pipe leaks and pipe failures by finding flaws and repairing them if necessary before leaks and failures occur.

The regulatory requirements for ISI are given and specified in 10 CFR 50.55a(g), which in turn references ASME Code Section XI for in-service inspection requirements.

Now, once again the ASME code basically requires different levels of volumetric or surface examinations, depending upon the class of the piping. For Class I piping. the code requires essentially 25 percent sample of in-service inspection of butt welds, and 7.5 percent inspection for glass tubes.

The regulation also provides that the applicant may use an alternative methodology for in-service inspection as long as the alternative provides an acceptable level of quality and safety. So that is the provision under which the risk informed ISI inspection has been implemented for the plants.

The current status of the risk-informed ISI applications and reviews is that approximately current information that we have from NEI is that approximately 99 plants have indicated that they would be implementing risk-informed ISI programs.

To date, we have received 71 applications and 28 are still anticipated.

MEMBER WALLIS: And so 99 is essentially everything?

MR. ALI: Pardon me?

MEMBER WALLIS: 99 leaves very few.

MR. ALI: Yes, the others may not have indicated that, but we think they might do that.

MEMBER WALLIS: They all will. They all will?

MR. ALI: Essentially, yes.

MEMBER APOSTOLAKIS: But the anticipated submittals, plus the submittals received, is a hundred. That may need a correction. That second number should be 28.

MS. KEIM: Which is in the handouts. The handouts have 28.

MEMBER WALLIS: Which is deterministic.

MR. ALI: We did catch that.

MEMBER APOSTOLAKIS: So you are saying that there will be no plants that will not do this?

MR. ALI: Essentially, yes.

MEMBER LEITCH: Now, what is the scope for those plants by and large?

MR. ALI: The scope in the beginning, some of the plants in the beginning did full plant, as well as Class I, II, and III. The trend after that has been for the plants to do -- more of the plants are doing Class I only. So that has been the trend.

But still there are some that are doing Class I and II. We have a detailed spread sheet on which plants have --

MEMBER LEITCH: Is that because they get caught up with alternate requirements like FAC inspections that sort of --

MR. ALI: Well, FACT, they cannot change FAC. It is our understanding that they will continue to do that. The IGSCC, only Category A can be subsumed in this program, and B through G, they still have to do the augmented program.

So why the industry is doing Class I? Only because that is probably that is where they get the biggest benefit, in terms of ALARA, and also the economic benefit.

And as you can see from this slide, this also shows that there are two methodologies that the staff has reviewed and approved, and this gives a breakdown of the submittals with respect to the methodology.

MEMBER APOSTOLAKIS: Do the two approaches yield the same results?

MR. ALI: Similar results. We have not

had the opportunity to apply the two methodologies to the same plant.

MEMBER APOSTOLAKIS: But wouldn't that be something that you would like to do?

MR. ALI: That was something that we had proposed to the industry to do it. They have not done it, and we just do not have the resources to do it, but you are right. We agreed that that would have been something that would have been beneficial to do.

But we know from the application of the two methodologies to similar plants that the results are similar, although we find that the Westinghouse methodology in general results in somewhat less inspections that the EPRI methodology, and that has been our general experience.

MEMBER APOSTOLAKIS: What would it take to do it? I mean, is it a major undertaking? Maybe take a plant for which the EPRI methodology has been applied, and ask somebody to apply the Westinghouse methodology, and vice versa.

I mean, we should have a better understanding of these things.

MR. DINSMORE: This is Steve Dinsmore. I think part of the problem is that you need to really go to the plant and do it at the plant, because it is very plant specific. It is not something that we could do here.

So that creates some difficulty and so it would be difficult for us, the NRC, to do it. We would have to ask industry, and there is really limited incentive for them to do it.

MEMBER WALLIS: Let's go back to your first bullet here. Is it successful because people like it, or is it successful because it is more successful at finding incipient faults or preventing things which could be risky for happening?

MR. ALI: Well, we don't have enough experience to say that it is actually successful in actually finding the flaws. So this bullet, really the first two, are successful in the sense that industry has adopted it.

MEMBER WALLIS: Sort of a ritualistic way. I mean, it is a nicer ritual for them to go through, but it has not gotten any results yet; is that what you mean?

MR. ALI: We have not had the experience yet to be able to say that it is --

MEMBER WALLIS: So it is successful only in the sense that people like it?

MR. ALI: And people have adopted it, yes.

MEMBER SIEBER: Actually, I think it is true that you end up doing fewer inspections.

MR. ALI: Right.

MEMBER SIEBER: And I think that is why people like it.

MR. ALI: Right.

MEMBER WALLIS: People agree that it makes sense, but you need a lot of experience to show that it is successful, in terms of enhancing public safety in any way.

MR. ALI: Well, your characterization of what is meant by successful is correct.

MEMBER LEITCH: The word methodology here refers to the method for determining the scope of the program. There is no difference in the inspection techniques is there?

MR. ALI: Not much, that is correct. The methodology is in terms of when it is applied to a plant, and let's say to a Class One piping, then what do you come up with as far as the required inspections.

The inspection methods are essentially the same, and a lot of other things, such as how to evaluate flaws, and what is the acceptable flaws, and the ASME periods, versus intervals, and all of those things are unchanged.

So the methodologies are similar in that respect.

CHAIRMAN BONACA: So the big difference is the locations?

MR. ALI: The differences could be locations and the number of inspections.

MEMBER APOSTOLAKIS: And the categorization is significant.

MR. ALI: Yes.

CHAIRMAN BONACA: But the result insofar as --

MEMBER SHACK: The result is the number of inspections.

CHAIRMAN BONACA: The number of inspections and the frequency of those inspections, and the location.

MR. ALI: And the locations.

MEMBER LEITCH: Could you refresh me on what the phase "super pipe" means in this connotation?

MR. ALI: Well, maybe we will come to that. That is one of the areas in which originally the methodology was not -- was exempted or was excluded to be applied to that piping, but since then it has been, and it is --

MEMBER LEITCH: So you are coming to that then?

MR. ALI: Yes, we are coming to that.

MEMBER LEITCH: Okay. Thank you.

MR. ALI: Okay. This is basically just stating that we issued the trial regulatory guide in September of 1998, as well as the standard review plan. You see also the second bullet that the safety evaluation report on WOG methodology, and SCR methodologies were issued later on.

So at the time that we issued the reg guide and the standard review plan, industry was developing generic methodologies at the same time. The industry was applying those methodologies to pilot plans, as well as the ASME was developing code cases. So a lot of those activities were going on simultaneously, and so that was the time frame.

The next slide, based on the lessons learned, and meetings, and discussions the staff had with industry, the staff and industry adopted the template submittals, which specified the contents of the request to implement this methodology.

And basically these were the submittals that included the description of the evaluation, the results, and any deviations from the methodology. The purpose was to have an efficient way of submittals and review, and then the industry or the utility to have the detailed results available at the site in case the staff wanted to audit, which was done in a few cases.

Some of the questions that the staff asked in the beginning eventually became part of these template submittals, and so the templates, although initially evolved, but then became stable.

MEMBER SHACK: What fraction of these do you actually audit in some detail?

MR. ALI: Well, I think we have audited about 4 or 5 plants if I am correct out of all of the ones that we have approved for this.

MR. DINSMORE: We usually have to have a reason to go audit. The last one we went to audit, we noticed, for example, that the CDF and the LERF values had changed substantially from the IPE to the submittal, and so we went down to see why that happened.

But if there is nothing that catches our attention, then we don't go audit.

MR. ALI: Part of the program is the updates to the risk informed ISI programs. So the program, once it has been implemented, is a living program which would be changed if there is new information to reflect a need for change, and that could include major updates to the PRA models.

MEMBER APOSTOLAKIS: What is a major update?

MR. ALI: These are --

MR. DINSMORE: These are kind of the long term processes, and we have not quite settled out on the long term processes. So we don't haves a real specific answer to that.

MR. ALI: But we have some specific guidelines for updating, and one of them is at least on a periodic basis, and on a periodic basis, which is for most of the programs that the industry has, the program is typically a 10 year program, and it is called an interval, and that 10 year program is divided into three periods; 3 years, 4 years, and 3 years.

So there is an agreement to update the program at least on a periodic basis.

MEMBER APOSTOLAKIS: And I guess from now on that you will demand PRAs that would comply with the standard and upcoming regulatory guide, which is now in draft form, DG-1122.

MR. ALI: Well, when we talk about the actual changes, Steve is going to talk about one of the areas, or one of the only areas in which there is actually what we call more than minor or editorial change, is in the PRA, and the incorporation of not only the staff who use IEEE, but also the peer reviews, but I think Steve will talk about that when he talks.

MEMBER APOSTOLAKIS: Okay.

MR. ALI: But the actual changes in the Reg Guide.

MEMBER WALLIS: But you are not really interested in the whole PRA are you? You are just interested in the part of it which is influenced by how you treat the piping systems?

MR. DINSMORE: That's correct. It is easier for Class One, because it is mostly just LOCAs. And one of the -- and when we questioned them about previously identified weaknesses, or that we have learned from the review process, and their PRA, they always have the option of saying that they can evaluate the weakness and say that it doesn't impact the submittal, and that is one of the two answers that we accept.

MR. ALI: Let's go to the next slide. Application to BER Piping, and that is the modification of inspections within the break exclusion region, and that is your question about the super pipe, and just to give a quick background on that, in order to implement the requirements of GDC-4, the staff had required that all plants postulate breaks in high energy piping when they met certain conditions, and the effect of postulate breaks and design for the effects of those breaks.

The effects could be things like pipe missiles, or jet impingement, pipe breaks. As a result of that, the plants were required to have a significant number of pipe (inaudible) restraints, jet shields, things like that, and since that was extremely difficult in the region which is between the first isolation valve inside, to the fast isolation valve outside the containment, in that region the staff in the branch position, MEB 3.1, came up with a different criteria.

That if certain conditions are met for that pipe, and that is the pipe that was called the super pipe, then the breaks do not have to be postulated. There are about seven requirements relating to the stresses in that piping, the fatigue usage factors, construction, such as welding of that piping to the supports, and minimizing the welding.

One of the requirements for that piping

was a 100 percent examination of in-service inspection of that piping, in order for the utility not to have postulate breaks in that region.

And so that is a program that is really not an ASME-11 program, and that was sort of an augmented program that was implemented to avoid designing and constructing jet impingement shields and pipe restraints in that region.

So what this line indicates is that since that requirement or since the implementation of all those requirements, the industry has done a study that there have not been a lot of flaws found in that region.

So it would be more appropriate to apply the risk-informed methodology in that region also. So in 2001, EPRI, as well as WOG, submitted their extension or their division to the topical reports to apply the risk-informed methodology to the super pipe of the BER region piping also.

The EPRI methodology for this region has been approved and the WOG methodology is still under review and the staff is having discussions, and it has not been reviewed and approved yet.

MEMBER LEITCH: So is it possible to say as compared with previously requiring a hundred percent inspection, is there -- what percentage of inspections --

MR. ALI: They might end up doing something like 10 percent, a significant reduction.

MEMBER LEITCH: A significant reduction.

MR. ALI: Yes.

MEMBER LEITCH: And the risk basis for that is -- relates to core damage frequency?

MR. ALI: Right.

MEMBER LEITCH: Is there any credit taken for dose saving, or is that --

MR. ALI: No, that is not -- I mean, there is obviously a significant dose saving, but that is not the criteria for the review of the acceptability of the methodology.

It is basically the Reg Guide 1.174 criteria for the CDF and LERF.

MEMBER LEITCH: Okay. So the dose saving is just an added benefit, but it is not particularly evaluated?

MR. ALI: Yes. Well, we had a -- and I forgot to mention this, but before coming here, we had a public meeting on the revision to the Reg Guide and Standard Review Plan in March.

And one of the comments, and we made a

similar presentation in that public meeting, and one of the comments that was made by NEI was that this -- that the application of this methodology has resulted in a significant radiation reduction.

I think maybe that could be part of the statement that you made, that it is successful in the sense that it has resulted in savings in radiation exposure.

MEMBER SHACK: Just while we are talking about the conclusion of this thing, there is a letter from Westinghouse that is in our package that makes a statement about another risk-informed ISI methodology approved later by the NRC was not required to address small bore piping.

Is there some difference in the way the two methodologies or the approvals treat the problem of having to inspect small bore piping?

MR. ALI: I think that was -- was that part of your presentation?

MR. DINSMORE: Actually, those are two different issues. I don't know if you are trying to talk about the break --

MR. ALI: No.

MEMBER SHACK: No, I looked through your presentation and I didn't see it being addressed. And since we were talking about scope here, I figured that this was another scope issue.

MR. DINSMORE: Right. These basic presentations are about the risk informed reg guide and SRP. The letter I think -- and we are prepared to talk about it, but it is not directly in the presentations.

And as far as that specific comment, with Westinghouse in their topical, they suggested including piping one inch or greater, and EPRI, I think, suggested including piping 2 inches or greater.

And we approved both, and if Westinghouse would come in and want to change from 1 to 2 inches, they could obviously come in with a submittal and a request to change the --

MR. ALI: Well, I think that is an issue which is -- which the staff is still discussing with Westinghouse. As a matter of fact, there is a meeting next week. So what will be the final outcome has not been determined yet.

MEMBER APOSTOLAKIS: Doesn't that again bring up again the issue of comparing the two methodologies? I mean, it should be done at some point to understand whether there are any differences, or assumptions, or methods for processing information?

It would seem to me to be an important -- we have had it now since 1998, and this is something that I would expect to see, because there may be other issues in the future where one or the other, and EPRI might say, well, gee, you are not asking the other guy to do this, and you have to be prepared for that.

I think that I have to agree with you that that would have to be something that would be useful and helpful to do. What I can do is take this back to my manager and division director, and say that that is what you are recommending now, and requesting, and now that I am in research maybe the NRR, their responsibilities are a little bit different now.

MEMBER APOSTOLAKIS: Careful now. Careful what you say. Are you freer now?

MR. ALI: No, I am not saying that. I wish I could say that.

MEMBER APOSTOLAKIS: No, I understand.

MR. ALI: All right. Okay. I think this is the last slide that we need to get into, which is getting into the actual changes.

Just basically, it states that our long term activity in this area have been to update the Reg Guide and the Standard Review Plan, and the first bullet is part of what we are doing.

Also, the staff has been working with the committees and groups to incorporate the lessons learned from the reviews into these cases that are relevant to the risk informed ISI.

I think that Appendix X, which includes both methodologies, is something that has been worked out to the staff's satisfaction. So that the Reg Guide 1.147, if that is still the mechanism to endorse, would endorse the appendix, and then once the appendix has been endorsed, then the methodology can be implemented without actually asking for exemptions from the staff.

And I think that is all that I have now, and Steve will go through the actual changes in the Reg Guide.

MEMBER LEITCH: I guess I just have a question about the risk informed part of this. It seems to me that in all cases we are reducing the number of inspections. Is there another side to that coin in looking at the risk information? Did we find that there were some areas where perhaps we should be doing additional inspections?

MR. ALI: Yes, especially for the plants that have applied this methodology, or this program, to the full scope. In other words, one, two, three, and maybe even beyond that, they have found that there were some additional inspections required.

When you reduce the inspections, that also means that you may be reducing in one particular system, but increasing in some other systems. So reducing does not mean that it is an across-the-board reduction.

Sometimes the inspections are moved to locations which are not considered to be susceptible, and to locations in a different system which might become susceptible.

MEMBER LEITCH: So we believe then that he overall impact of this program would be to increase safety?

MR. ALI: Increase safety and reduce risk.

MEMBER LEITCH: Well, I understand the increase safety and reduce risk, but not just reduce work.

MR. ALI: Right.

MEMBER APOSTOLAKIS: Don't they go together?

MEMBER LEITCH: Not just reduce work, and reduce exposure, but also increase safety and reduce risk?

MR. ALI: Yes.

MEMBER APOSTOLAKIS: When You increase safety, don't you reduce risk?

MEMBER SIEBER: Yes.

MR. ALI: Yes.

MEMBER WALLIS: Well, there is no such thing as increasing safety, because you can't measure it, but you can measure reduced risk.

MR. ALI: Reduced risk.

MEMBER APOSTOLAKIS: Boy, stunned silence.

MEMBER SIEBER: We are considering.

MR. DINSMORE: Okay. Well, I guess I will start. Again, my name is Steve Dinsmore, and I am the PRA Branch at NRR. I am going to go over the actual changes to the Reg Guide that we -- the Reg Guide and the SRP.

As I had said, we issued this Reg Guide and SRP for trial use, and we did that because of the three pilot applications weren't complete and the review of the two industry methodologies were also not complete. So we didn't feel confident enough to --

MEMBER APOSTOLAKIS: We had this issue here a month or two ago in the context of another regulatory guide. If you had called this RG Rev. Zero, and this what we are doing as Rev. 1, what would have been different?

The committee is trying to understand what the trial use is.y

MR. DINSMORE: I can answer that to some extent for this specific reg guide.

MEMBER APOSTOLAKIS: Yes.

MR. DINSMORE: Essentially the difference between the draft, or between a real reg guide and the trial use reg guide, for our reg guide, it was that the trial use reg guide, it actually states in the reg guide that the trial use means that it does not establish any final staff positions, and may be revised without having to consider the back fit rule.

So we could add requirements if we thought that there wasn't enough requirements in the original trial use version.

MEMBER APOSTOLAKIS: And if it is a regular regulatory guide, the --

MR. ALI: If it was at zero, then it may have just stayed like that; whereas, this flagged that it has to be revised.

MEMBER APOSTOLAKIS: No, I mean, if something had been approved under Rev. Zero, and then you decide to go to Rev. 1 with additional requirements, then it would have required a regulatory analysis?

MR. DINSMORE: That is what it implies from reading the text in the Reg Guide, especially if you added requirements. For example, if we said 2 inches was good enough, and then we said, oh, you have to go down to one inch, we might have to have done -- or at least my understanding is --

MEMBER APOSTOLAKIS: But is that what happens every time we increase the requirements with a regulatory guide?

MEMBER SIEBER: Yeah.

MEMBER SHACK: Increased requirements, yes.

MR. ALI: That's correct.

MEMBER APOSTOLAKIS: And so in the preparation of Rev. 1, they would have to do this, and not the licensees? I mean, these guys would have to go back and say we want to add this requirement, and now we have to do a regulatory analysis.

Whereas, if it is trial use, you don't have to do it.

MR. DINSMORE: That's correct. And the difference between the trial use and the draft, I am pretty sure has to do with the concurrence chain, and who has to agree to it.

The drafts are relatively easy to put out, and when we put out this one for trial use, it ended up going to the Commission under a memo from the EDO. So I think that is the difference between the draft and the trial use.

MEMBER WALLIS: I think that trial use would imply some measures of success which you want to evaluate after the trial.

MR. ALI: Right. And I think it was also to flag that it would be revised. If it said Rev. Zero, it could just stay like that.

MEMBER WALLIS: Yes.

MR. ALI: But there was an intention that we knew that it was going to be revised.

MEMBER WALLIS: Not only revised, but it is going to be evaluated. That you try it, and then you see how well did it work.

MR. ALI: Right.

MEMBER APOSTOLAKIS: And also the pilot organizations are aware that they may be asked to do more later. Otherwise, they are not even pilots. Just do it.

MEMBER SIEBER: Is there any limit to how you can apply for trial use? For example, you cold eliminate the back fit rule by making everything for trial use, right?

MR. DINSMORE: I have no idea.

MEMBER SIEBER: Is there a time limit on how long the trial lasts?

MR. ALI: What we are saying is that it is not that when we issue something for trial use that you don't have to do back fit at that time. It is when you go from trial to the next revision, that's when you don't need --

MEMBER SIEBER: Right. So you put out an easy one, and change it, and --

MEMBER APOSTOLAKIS: But that is a good question. Why aren't all the regulatory guides for trial use? That is a clever way of defeating the regulatory analysis.

MEMBER SIEBER: There you go.

MEMBER APOSTOLAKIS: Is there in fact a time limit that you cannot do this for 20 years? Is there a regulatory guide for trial use for 20 years?

MR. DINSMORE: We have had draft reg guides for 20 years. We didn't get any pressure based on the fact that it was trial use to update it. We got pressure to update it with 1.174. So I don't think there is any --

MEMBER APOSTOLAKIS: Does the Office of

the General Counsel know these things? Maybe we should ask somebody there.

MEMBER SIEBER: It is probably their words that are in there.

MEMBER WALLIS: Do they need to know, George? I mean, there is room to maneuver, and just leave it to you have room to maneuver.

MEMBER APOSTOLAKIS: But for how long?

CHAIRMAN BONACA: For 20 years.

MR. ALI: Well, you see, we came back within 5 years.

MR. DINSMORE: Well, the proposed changes are minor that we have suggested. We held a public workshop on March 13th, 2003, to discuss the proposed changes with industry.

In general, they were fairly positive, and there was no major comments on the proposed changes.

MEMBER WALLIS: Are you saying there was a public workshop for the purposes of discussing changes with industry?

MR. DINSMORE: Okay. It was to discuss changes with any of the public who wished to attend.

MEMBER APOSTOLAKIS: Now, Steve, would you say that since the proposed changes were minor after five years, the decision to go with a trial use guide was wrong?

MR. DINSMORE: No. Well, we didn't know. Again, these two methodology are both pretty complicated methodologies, and we were right in the middle of trying to figure out all the implications of using them.

So that was the -- and then there was a certain desire to put these reg guides out on the street. In other words, not to keep just pushing it off and off. And so the solution --

MEMBER APOSTOLAKIS: So there was a lot of concern, but it turns out that you were right on most major elements?

MR. DINSMORE: Yes.

MEMBER APOSTOLAKIS: Which is okay.

MR. ALI: Also, I think that the reg guides are -- you know, since we had in this case specific methodologies which are very detailed implementations of how the program is to be developed, and so the reg guide and standard review plan are at the higher level.

And so we feel that at that level that there has not been any significant change.

MR. DINSMORE: We have three types of changes. We have one here called incorporate lessons learned from review of submittals, and we called those clarification changes.

And essentially what that was is those are changes which we made to the reg guide and the SRP to make them better conform to the actual practices that we are using to review the ISI submittals.

Then we have this update and simplified text, which is a bunch of editorial changes. Then we have this one proposed content change, which adds guidance which is not yet been applied to the risk-informed ISI submittals.

And the content change is PRA quality. When we started these ISI reviews, there was really very few licensees that had a peer review on their PRA, and so I think our belief, and one of the reasons that why ISI has done fairly well is that it is a pretty easy and straightforward application.

You just need to relocate your inspections to places that have the highest risks. So we were somewhat flexible about the quality of the PRAs that we were supposed to use, because they are only being used to support putting things into two bins, and then we thought that most of the reviews that had been performed would have identified the major errors which could have impacted those of putting stuff in bins, and that the minor errors would have relatively minor impact.

But as time goes on, we would like to take advantage of all of the information that was available, and so we have added this requirement. Some licensees lately have been including this requirement.

The PRA qualities documentation requirement was expanded to include the observations from industry peer reviews, and a resolution of significant comments applicable to the ISI evaluation, which is what we have been asking them to do for the weaknesses and deficiencies that were identified by the research staff evaluation reviews of the IPEs. So we have pretty much just raised the bar a little bit.

MEMBER APOSTOLAKIS: Both methodologies use performance measures? I don't remember whether EPRI does.

MR. ALI: Only Westinghouse.

MR. DINSMORE: EPRI uses an absolute value dividing line based on the conditional core damage probability.

MEMBER APOSTOLAKIS: I would really like to see a comparison now between the two methodologies. Now, Westinghouse, they are categorizing system structures and components, right? And then they go to the piping to see how --

MR. DINSMORE: No.

MEMBER APOSTOLAKIS: They categorize the pipes themselves?

MR. DINSMORE: Yes.

MEMBER APOSTOLAKIS: Through the systems affected?

MR. DINSMORE: Yes, they look at the pipe that is going to rupture, and they look at the equipment which is going to fail if you rupture that pipe, and then they fail that equipment in the PRA.

MEMBER APOSTOLAKIS: Right. So it is through the equipment?

MR. DINSMORE: Right.

MEMBER LEITCH: It is a surrogate again.

MEMBER APOSTOLAKIS: Yes.

MR. DINSMORE: And EPRI does the same thing at that point.

MEMBER APOSTOLAKIS: Now, that kind of categorization is also done in 50-69?

MR. DINSMORE: That's right.

MEMBER APOSTOLAKIS: And the two are the same?

MR. DINSMORE: Well, for the ISI stuff,

because the pipe, or the consequences of pipe ruptures are not directly in the PRA, there is an extra step.

MEMBER APOSTOLAKIS: I understand that, but if I look at the components, the categorization, I will not find one component being non-safety significant in the ISI context in the safety significance in the 69 context? I hope not.

MR. DINSMORE: They are different sets of components.

MEMBER APOSTOLAKIS: Who makes sure that those happen or doesn't happen?

MR. DINSMORE: Well, we have a general statement in 1.174 that the categorization, that the importance might well depend on what you are going to do with it. So what we are doing here is we are changing the inspection requirements on piping welds, which is a relatively benign change. We are talking about --

MEMBER APOSTOLAKIS: Well, the categorization depends on the PRA, and it doesn't depend on what we intend to do. It just says find Fossell-Vasely and if it is greater than this number, then we will do this.

So the intended action is not part of the categorization. What I am driving at is the plant, since a lot of these activities now rely on this categorization, the plants have one categorization, and then in your case, you have to go this extra step that you mentioned, because the pipes themselves are not in the PRA.

But if I go back to the component or system, I should be able to say, well, this is the categorization for this system at this plant. That is the coherence of the regulations isn't it?

MR. ALI: Isn't the 50-69 classification based more on the conditional core damage frequency?

MEMBER APOSTOLAKIS: No, it is importance measures.

MR. DINSMORE: We have two classification systems. One of them is used for ISI, and the other one is used for repair and replacement. The repair and replacement one is more stringent.

But if you had a valve and the valve failed to open, you would have a certain consequence. If the valve ruptured, it could have a much greater consequence. So it is not entirely clear that the importance of this valve would be the same if it failed to open, as opposed to rupture and spit water all over.

MEMBER APOSTOLAKIS: But wouldn't the PRA include those failure modes? I mean, we hope that it would.

MR. DINSMORE: Well, it --

MEMBER APOSTOLAKIS: Because the PRA finds -- the way it is done now, it finds the importance of the events. So these events have to be there to begin with.

I mean, I can't imagine that in one categorization we say that this valve we consider only the failure to open failure mode, and it is characterized as a risk significant, or non-risk significant, safety significant.

And then if you consider that it can fail in another way, then what kind of PRA is that?

MR. DINSMORE: Well, I do think that if you are talking about changing test intervals on that value, and the thing is locked close -- well, that doesn't quite make sense, but if you change test intervals on the valve, you would evaluate it based on it not being able to open.

But if you change the material properties of the valve body, you might be more interested in what happens if it ruptures.

MEMBER APOSTOLAKIS: Absolutely. Absolutely, yes.

MR. DINSMORE: But then if you added those two together, then it would make it high safety significant. Then you would have to test it, even though the testing didn't maybe contribute much to the failure mode, which is causing it to be high. And which would be the rupture of the valve body.

MEMBER APOSTOLAKIS: Well, you know, when we reviewed the Draft Guide 11.22, it was supposed to set the standard for a good quality PRA, high quality PRA, that could be in all regulatory applications.

And in some instances, you may have to do more. Like in your case, I think you have to do more. But in fundamental failure modes, they are presumed to be already in that model.

So maybe somebody has to worry about that consistently. Mary Drouin made a presentation to us, what, 2 or 3 months ago, on regulatory coherence. Maybe this is an issue for that problem, is to make sure that there is consistency in categorizing SSEs.

MR. DINSMORE: Well, there is categorization of piping which can be done in 50.69. So we will take a look and make sure that it is consistent.

MEMBER APOSTOLAKIS: I don't remember the 50.69, but that's fine. Okay.