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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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REGULATORY POLICIES AND PRACTICES SUBCOMMITTEE

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WEDNESDAY,

SEPTEMBER 22, 2010

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 8:30 a.m., William J. Shack, Chairman, presiding.

SUBCOMMITTEE MEMBERS:

WILLIAM J. SHACK, Chairman

SAID ABDEL-KHALIK, Member

J. SAM ARMIJO, Member

MICHAEL L. CORRADINI, Member

HAROLD B. RAY, Member

JOHN W. STETKAR, Member

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

8:30 a.m.

CHAIRMAN SHACK: The meeting will now come to order. This is a meeting of the Regulatory Policy and Practices Subcommittee. I am William Shack, Chairman of this Subcommittee meeting.

ACRS members in attendance are Harold Ray, Sam Armijo, Said Abdel-Khalik, John Stetkar and Michael Corradini. Peter Wen of the ACRS staff is the Designated Federal Official for this meeting.

The purpose of this meeting is to review the draft final rule on risk-informed changes to loss of coolant accident, technical requirements, 10 CFR 50.46a and this new rule, that will be `a' without parenthesis.

We will hear presentations from representatives of the NRC staff. We have received no written comments or request for time to make oral statements from members of the public, regarding today's meeting. The entire meeting will be open to public attendance.

The Subcommittee will gather information, analyze relevant issues and facts and formulate proposed positions and actions, as appropriate, for deliberation by the full Committee.

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

A transcript of the meeting is being kept and will be made available, as stated in the Federal Register notice. Therefore, we request that participants in this meeting use microphones located throughout the meeting room, when addressing the Subcommittee.

The participants should first identify themselves, and speak with sufficient clarity and volume, so they may be readily heard.

The ACRS has reviewed other versions of this rule in the past, as well as the NUREGs on the frequency of LOCAs and the effect of piping degradation and piping seismic loading on a selection of the transition break size.

Our last report on 50.46a called for revisions in the then current version of the rule, to strengthen the assurance of defense and depth for breaks beyond the transition break size, and restrict the changes that could be made, without prior NRC review.

This version of the rule addresses those issues, as well as additional Commission direction on

the increases and risk associated with changes made under the rule.

We will now proceed with the meeting, and I call upon Ted Quay, of the Office of Nuclear Reactor Regulation, to begin.

MR. QUAY: Thank you. Good morning. My name is Ted Quay. I'm Deputy Director of the Division of Policy and Rule Making, in the Office of Nuclear Reaction Regulation.

The staff is here today to discuss the draft final 50.46a, risk informed ECCS rule. The development work to support the revision to the NRC's emergency core cooling regulations was initiated over 11 years ago, by a June 1999 Commission staff requirements memo.

The Office of Research then began a major effort to assemble the technical basis for this rule making. Research staff members have provided continuing support for this project, since it began, and are still key contributors to the project.

Rule making was begun six years ago by the Office of Nuclear Reactor Regulation. The approach has been coordinated with the Office of New Reactors. The ACRS has been briefed many times on this rule and on related studies. Through its comments, the ACRS

has already made key contributions to this effort.

I would like to introduce the NRC staff members who will make today's presentation.

Richard Dudley is the NRR rule making Project Manager. He has worked on this rule for six years. Steven Downey is here to represent the Office of New Reactors. He has been involved for two years.

Rob Tregoning is the representative from the Office of Research. Rob has worked on this project for more than eight years.

Sitting behind me are Tim Collins and Stephen Dinsmore. Tim Collins is the NRR technical coordinator for the rule. He has worked on this rule for six years, and Steve Dinsmore is the NRR staff member, working on the risk analyst aspect of the rules. He has been involved in the effort for seven years.

With that, I would like to turn it over to Dick Dudley, to start the staff presentation. Thank you.

MR. DUDLEY: Thanks, Ted. Before I start, I'd also like to mention Ralph Landry, although he's not speaking today, he's worked on this rule for, I believe, seven years, right, Ralph? Right.

Okay, I'd like to start with a little

overview of our presentation. First, I'm going to give a short background, history of this ruling making. Then, I'm going to summarize the 50.46a rule concept.

After that, Stephen Downey will talk about applying 50.46a to new reactors, and then we'll have a break.

After the break, Rob Tregoning will talk about -- Rob is not here. He'll be here shortly. We'll talk about public comments we received on the transition break size, and on the applicability of generic studies and some applicability review guidance that the Office of Research is preparing.

After lunch, Tim Collins will talk about the public comments we received related to thermal-hydraulic analysis, and following him, Steve Dinsmore will talk about the comments related to risk assessment, and there are a number of rule changes that we made, as a result of those risk assessment comments.

There will be a break, and then I'll follow, just discuss a couple of miscellaneous comments, and then the Committee will have its discussion.

CHAIRMAN SHACK: When you mentioned rule

language changes, now, those are all incorporated in the version that we have?

MR. DUDLEY: Yes, yes.

MEMBER CORRADINI: They're not tracked, though. We don't -- you'll identify them for us, as we go along?

MR. DUDLEY: Yes.

MEMBER CORRADINI: Okay, thank you, or the key ones, I should say.

MR. DUDLEY: The key --

MEMBER CORRADINI: Excuse me, I'm sorry.

MR. DUDLEY: -- will be identified, that's right. The track changes version would be really messy, it would.

Okay, slide three, the rule making started in March of 2003, when we received the Commission SRM, directing us to prepare a proposed rule to risk inform the ECCS requirements.

We struggled with that SRM and a year later, we went back to the Commission in March 2004, for additional guidance because some of the guidance in the initial SRM was either contradictory or conflicting, and we just -- we couldn't proceed.

So, we went back to the Commission. We got additional guidance. We got clear direction, in

July 2004.

In response to that direction, we published the proposed rule in November 2005.

Nearly all of the commenters on the rule were industry comments and nearly all of the industry commenters said that the rule, as proposed, had excessive burden and because of that excessive burden, licensees would not likely have wide spread implementation of the 2005 version of the rule.

In response to these comments, we held two public meetings to discuss the public comments and our response to those public comments, and to also discuss and see if we could find some ways to reduce any unnecessary burden, but still, preserve adequate safety.

We completed and formulated a draft final rule and we met with the ACRS to discuss that draft final rule in October and November of 2006.

The ACRS gave us their views in a November 16th letter. In that letter, the ACRS said that the rule to risk informed 50.46 should not be issued in its current form.

The ACRS saw that there was insufficient defense-in-depth in the rule for pipe breaks larger than the TBS. The ACRS was concerned with the way we

had set up the risk informed assessment process and the ACRS also was concerned that there was no requirement to have a plant specific applicability review of the two generic reports, the expert solicitation and seismic analysis report.

In response to the ACRS letter, because of the significance of the Committee's comments, and because some of those comments seem to be conflicting with the existing Commission guidance that we have -- that we had, the staff went back to the Commission and requested additional guidance.

We got an SRM in August of 2007, and in that SRM, the Commission agreed with the ACRS that we should strengthen the rule to increase the defense-in-depth for breaks larger than the TBS.

So, with that guidance, we completed another draft final rule, and when we gave that rule to our Office of General Counsel to review, the lawyers determined that we had changed it so substantially, between what we published in 2005 and what we had in 2009, that we needed to go back out for additional public comment on that current version.

With that version, we briefed the ACRS in May of 2009 on the changes that we had included in -- and that version, we call the supplemental proposed

rule.

We published the supplemental proposed rule in August of 2009. The public comment period ended in January. We evaluated public comments and we prepared draft final rule language.

We made that draft final rule language public, posted it on public website in May of this year, and we held a public meeting to discuss that draft final rule language in June 2010.

After the public meeting, we made some additional changes to the rule and we prepared the draft final rule language that we provided to the ACRS on August 22nd. We posted that identical language publically on (regulations) reg.gov, on September 7th.

Moving forward, the Subcommittee meeting is today. The full Committee meeting is October 7th. We're requesting a letter from the ACRS, and we would expect that in a couple of weeks, after October 7th.

We'll review the ACRS letter and based on what it says, we'll decide to go forward. Then, we'll provide the final rule package to the EDO, the end of November, and the package should go to the Commission, about mid December.

Are there any questions on the history, the background of this?

(No response.)

MR. DUDLEY: Okay, next, I'll summarize the rule concept.

Fifty-forty-six-a is an alternative to the existing ECCS requirements in Section 50.46. Licensees may choose whether to stay with 50.46 or try to get approval to implement 50.46a.

Under 50.46a, the spectrum of LOCA break sizes is divided into two regions, by the transition break size, or TBS. The ECCS requirements for LOCAs in the first region, the smaller, more frequent breaks are unchanged from the current requirements.

But in the second region, the larger breaks, larger than the TBS, based on their lower frequency, we have relaxed the LOCA mitigation requirements for breaks larger than the TBS.

Because of this change from the existing requirements in Section 50.46, some plants will be given additional design flexibility. That will allow them to make some plant changes, under 50.46a, that they normally couldn't make under Section 50.46.

We called those enabled changes, and all changed enabled by 50.46a, in addition to meeting the ECCS requirements, they also have to meet a risk informed evaluation and meet the risk informed

acceptance criteria.

MEMBER RAY: What is an example of an enabled change, just --

MR. DUDLEY: You might be able to slow-start diesels, something like that. We thought at one point, that we might be able to take an accumulator out of service, that sort of thing.

MEMBER RAY: Power upgrade?

MR. DUDLEY: Power upgrades would definitely be an option, as an enabled change.

MEMBER ARMIJO: Are there any relaxations for pipes below the transition break size, or is it --

MR. DUDLEY: The requirements -- no, there are not. The requirements are identical.

MEMBER CORRADINI: But the -- we're going to get to this in the second discussion, I think, but if one were to have a newer plant, the decision of what the transition break size is would have to be re-evaluated for a newer plant design.

It wouldn't be -- the TBS is not design independent. It would be design specific.

MR. DUDLEY: Right, right, and we'll discuss new plants.

MEMBER CORRADINI: That's fine, I just wanted to make sure I understood.

MR. DUDLEY: Okay.

CHAIRMAN SHACK: I would like to ask Ralph Landry a question, that was coming to mind, and that goes back to the way we treat large break LOCAs now, in best estimate calculations. At least one of the best estimate calculations, you actually sample the pipe size, as well as everything else in the best estimate, is that correct?

MR. LANDRY: This is Ralph. Is this on?

CHAIRMAN SHACK: Yes.

MR. LANDRY: Ralph Landry from the staff. Yes, there is at least one realistic LOCA methodology, which the break size is sampled. It's sampled in a uniform manner.

CHAIRMAN SHACK: Okay, that was my question.

MR. LANDRY: The probability distribution function is united.

CHAIRMAN SHACK: Is united?

MR. LANDRY: So, every break size is equally probable. It doesn't weight the break size in the sample.

MEMBER CORRADINI: So, all it does is just create a sensitivity to how the accident proceeds, given the size of the break.

I didn't understand. I guess, I just assumed that you to take a spectrum. You're saying that it's part of the methodology for the realistic --

MR. LANDRY: Part of -

MEMBER CORRADINI: You would basically just choose a range of breaks and watch the behavior.

MR. LANDRY: Part of the sampling approach is that one of the parameters that is sampled is the break size. In one of the others, break size is not sampled. The work -- the most limiting size is determined and then all the analyses are done for that most limiting size.

The one methodology permits sampling the break size, as a sample parameter.

So, when you do that analysis, you can end up with `x' many calculations, each one of which is a different size break.

MEMBER CORRADINI: But just -- since it's uniform, wouldn't you end up with the same result that the limiting size would be the largest -- would be the most challenging to the system?

MR. LANDRY: That's what we found.

MEMBER CORRADINI: Okay.

CHAIRMAN SHACK: But still, you only need 95/95.

MR. LANDRY: Right, if you remember what a LOCA spectrum looks like, you get a double-hump in a PWR, a small break hump and a big hump, in the large break spectrum, and this is only in the large break spectrum.

When that sampling was done, using that methodology, sure enough, every size fit what would have been that major large break hump, and it said that the worst size was what would normally be thought of as the worst size, .6 to .8 times the double end of that area. So, everything fit.

MEMBER CORRADINI: Okay.

MR. DUDLEY: Okay, the ECCS analysis requirements for the two regions, as I said before, less than or equal to the TBS. There's no change from the current requirements.

Breaks larger than the TBS, a licensee would not need to assume a single failure. Licensee would take credit for off-site power, and could take credit for the use of non-safety equipment, if some source of on-site power is provided to that equipment.

It wouldn't need to be automatically aligned, wouldn't need to be safety grade, but just some source of on-site power, to the equipment, to take credit for that.

And if a licensee can justify them, they could propose if -- and we may approve, alternative metrics for determining coolable geometry, alternatives ■- other than the 2200 degrees Fahrenheit and the 17 percent oxidation criteria that we use now, in 50.46.

MEMBER CORRADINI: But that would have to be proposed by the licensee on a case-by-case basis, otherwise, you revert to the traditional definition, is that correct?

MR. DUDLEY: It would have to be proposed by the licensee. I don't know if their proposal would be plant specific or not, but a licensee would have to -- it would be a substantial hurdle to demonstrate the acceptability --

MEMBER CORRADINI: Okay, that's what I was trying to get at.

MR. DUDLEY: It would be a substantial hurdle, and we don't expect that to be very likely.

MEMBER CORRADINI: Okay.

MEMBER STETKAR: Later on, are you going to come back to the electric power supplies? I haven't had a chance to go through your more detailed presentation.

MR. DUDLEY: I'm not sure. Why don't we go

ahead and --

MEMBER STETKAR: Okay, let me ask a question then. I understand the philosophy. I have no problem with the philosophy.

But as I read through the information that we received, a few places, I had some questions about the more technical information in the supplementary information, regarding the rule, which is publically available and kind of, shows the Commission's technical basis for some of the rational.

In particular, in the off-site -- in the power supply area, in the supplemental information, there are examples that says, "Well, it would be okay if you could provide power to equipment within 30 minutes."

MR. DUDLEY: Yes, right.

MEMBER STETKAR: That's -- I guess my question is, why do we have to specify a time?

The rule does not. The rule just says readily available.

MR. DUDLEY: Right.

MEMBER STETKAR: But the staff's interpretation of the rule that is going to be read by people who try to understand how to implement this thing, has that wonderful 30 minute criteria in there,

and that -- why 30 minutes?

MR. DUDLEY: Well, you had to give some idea of what readily available meant, and we picked 30 minutes because we consider this an accident mitigation issue. It's not an accident prevention.

That power will not be available quickly enough, before you will probably have some core damage.

MEMBER STETKAR: I guess the reason for my concern is that there have been interim staff guidance, and I don't know whether it's -- I think it's in formal regulatory guides, but I haven't taken the time to go do the homework, regarding the timing of operator actions, and the current process seems to say that we're going away from these fixed 30 minute, 20 minute assumptions, and saying that someone should demonstrate that the time required to perform an action, with some margin, is less than the time available.

And it's okay, if there's only 15 minutes available, as long as the guy can do it, you know, in three minutes, for example, would be fine, or if there's 70 minutes available and it takes him 82 minutes, that's not good.

So, this arbitrary 30 minute time frame

seems to be somewhat --

MR. DUDLEY: Well, 30 minutes --

MEMBER STETKAR: -- inconsistent with guidance that's being published this year, regarding this issue of operator intervention.

MR. DUDLEY: Thirty minutes is not, I guess, necessarily a hard and fast number. It was just to give an idea of what that might -- time period might be --

MEMBER STETKAR: I guess --

MR. DUDLEY: -- and if a licensee had a situation where they could have it in 35 or 40 minutes, and they could demonstrate why that would still be adequate to mitigate the accident --

CHAIRMAN SHACK: I think John is more worried about the other concern --

MEMBER STETKAR: See, my concern is that --

CHAIRMAN SHACK: -- that it will go in the opposite direction --

MEMBER STETKAR: -- is that people will say, "I have done the demonstration that says, "I can do it in 30 -- or I have 30 minutes available, therefore, I don't need to do anything else," because that's your interpretation of success.

MR. DINSMORE: Yes, excuse me, this is

Steve Dinsmore from the NRR.

I think part of the answer to your question is when they do the change in risk analysis, they're going to have to determine how long it's going to take this guy to hook this up, if they need it, and there will be a risk associated with him not hooking it up.

So, this 30 minutes is there, it's like -- maybe you could consider it as a design goal. But when they do the change in risk, that they'll have to do these analyses that you're speaking about, if they want accredit it.

CHAIRMAN SHACK: But Steve, that's okay, when you're proposing a change. This is sort of their basis analysis of the mitigation, is John's concern, and I'm not sure that you're doing the risk analysis for that.

MR. DINSMORE: We attempt to do the risk analysis to support the proposed change.

MEMBER STETKAR: You actually would have to do the risk analysis --

MR. DINSMORE: Okay.

MEMBER STETKAR: -- to do this -- the change. My fundamental concern is that, I think the agency needs to be very careful about specifying

numbers that may be inconsistent in one set of guidance, or the explanation of that guidance, compared to other sets of guidance, and in a lot of interim staff guidance -- and I think -- I have to apologize, I didn't go look up the Reg Guide, but there is guidance that now says that we don't endorse the notion of simple arbitrary time estimates for operator actions, as a go/no-go pass/fail for success, that the current agency guidance seems to be that you need to do an evaluation.

Now, you're right, Steve, if somebody does the correct risk assessment, they should do that evaluation.

However, you know, I can play the devil's advocate. Somebody can fall back and say -- the staff has implicitly accepted at 30 minute window, so therefore, as long as I can demonstrate that I have -- that I can -- that I have 30 minutes, I'm okay. I don't -- you know, I can essentially guarantee success. You told me I can do that.

MR. DINSMORE: Yes, as long as you continue to meet the change in risk criteria. But I --

MEMBER STETKAR: No, but the --

MR. DINSMORE: I can see the --

MEMBER STETKAR: Put the operator a zero.

MR. DINSMORE: Well, no, not in the change of risk analysis.

MR. DINSMORE: This would kind of alleviate -- this doesn't really address your problem, but it might alleviate it --

MEMBER STETKAR: It might alleviate it. I'm just -- you get my point.

MR. DINSMORE: Yes.

MEMBER STETKAR: I'd like to keep, if we could, specific numbers out of the technical basis for guidance, especially where those numbers are inconsistent with other parts of guidance.

It doesn't affect the wording in the rule, because the wording in the rule just simply says that a source of power must be readily available, which is appropriately vague and someone has to justify what readily is.

MR. COLLINS: This is Tim Collins from the staff. I just want to make sure it's clear here.

This off-site power is not used -- or this on-site power is not used in the mitigation analysis that's required in the rule. They can take credit for off-site power, for the mitigation analysis. Okay, this is not for the mitigation analysis, okay. I think Dr. Shack's statement indicated, he thought

maybe it was, okay.

This is for a severe accident radiation. This would be something in the SAMG's, okay, just an idea of -- you know, you need to -- something that will actually help you contain a severe accident within a vessel, basically, is what we're hoping here.

MEMBER STETKAR: Understand, but the same principles of operator performance and being able to demonstrate the effectiveness or the ability of the operators to perform whatever actions are required, applies, regardless of whether it's accident mitigation or severe accident --

MR. COLLINS: I understand, I just wanted to make sure that you understood that it was not for the mitigation that the rule requires.

MR. DUDLEY: Any other questions on that topic?

MEMBER CORRADINI: Not that topic, the third one, I had a question about, credit for non-safety permit.

Are you going to come back and talk about that, relative to how we -- how you monitor -- how you will required the licensee to monitor that equipment, to make sure that it's -- or are you not going to talk about that?

Will you talk about that later? If so, it can wait. If not, at least I want to understand, where we are there.

MR. DUDLEY: I'm not sure that we'll talk about it later.

MEMBER CORRADINI: Okay, so, can we talk about it now, then?

MR. DUDLEY: Sure.

MEMBER CORRADINI: So, if -- and again, I'm not exactly sure, I think for new reactors, I think I have, unfortunately, a better picture, just because I've studied them, for current reactors.

Can you give me an example of a non-safety piece of equipment that could be called upon to take credit for, and then how that's treated, with the rule?

MR. DUDLEY: I think we couldn't find anything in PWRs. For BWRs, what was the possibility?

I don't know, I really can't give you a good example.

MR. DINSMORE: I don't think we heard the question. I'm sorry, we were trying to answer the original question, sorry.

MR. DUDLEY: Okay.

MEMBER CORRADINI: Okay, so, my question

really is, what I'm trying to understand is, what does that third bullet mean, relative to -- so, let's just hypothesize -- I have a hypothetical, that there was a pump that's non-safety, that could be used in a PWR, if I'm above the TBS.

So, what are the maintenance and surveillance requirements for that piece of non-safety equipment, since I'm now going to start taking credit for it?

MR. DUDLEY: I think we decided that that would be covered by the maintenance rule.

MR. DINSMORE: But the maintenance rule will require you to put into the maintenance rule scope, equipment which is relied on to -- I'm not quite sure of the phrase, but relied in your accident sequence analysis, and the --

MEMBER CORRADINI: So, they wouldn't be in the tech spec's, but they'd be part of the maintenance rule?

MR. DINSMORE: That was the conclusion we reached with the maintenance rule folks, yes.

MEMBER CORRADINI: My light -- my scholarly partner here, is already checking.

MEMBER STETKAR: I thought, I had a question on that, and I can't find my notes.

MR. DUDLEY: And in addition, that equipment would have to be monitored and reliable data would have to be kept, and that would have to be input to the PRA.

I mean, the assumed reliability of that equipment goes as an input to the PRA, and then the risk informed process requires you to monitor that equipment and determine if your assumed probabilities are correct, and if they're not, you have to update the PRA.

MEMBER CORRADINI: But the reason I'm asking the question, just so you can see why I'm asking the question, the reason why I'm asking the question is, when I first started on this lovely Committee, and -- four years ago, we were here, I think, in the September meeting, and we had a presentation, or maybe a Subcommittee meeting, and this was the sticking point that I seem to remember, that most of the members were quite concerned about, and I'm trying to understand how this was resolved from that part of the rule.

CHAIRMAN SHACK: As I understand it, you're still requiring anyone -- any equipment credited for compliance with the ECCS requirement to be identified in the plants technical -- and at the 14 days

cumulative outage.

MR. DUDLEY: That's the availability requirement.

CHAIRMAN SHACK: Right.

MR. DUDLEY: That's right.

MEMBER STETKAR: But it says that it's -- Bill found the quote, "Is identified in plant technical specifications."

MR. DUDLEY: Okay.

MEMBER STETKAR: Now, that doesn't seem consistent with the maintenance rule, nor does it seem consistent with the RTNSS --

MR. DUDLEY: The purpose of listing --

MEMBER STETKAR: -- or a new plant -- new reactor.

MR. DUDLEY: -- the equipment in the plant technical specifications is to implement the Commissions' direction that that equipment cannot be removed or modified without NRC approval.

So, we would list it in the technical specifications. It would not have an LCO or anything associated with it. It would just be a listing to force a licensee to come in with a license amendment, in the event the licensee wanted to change the way they used that equipment, or take something out.

So, that's what we're using, that was the --

MEMBER CORRADINI: But except for that, it would revert to the maintenance rule, in terms of surveillance and operability.

MR. DUDLEY: Well, availability is controlled by the short period of time, which is either less than or equal to 14 days, or some other period approved by the NRC.

Reliability, the licensee would set the target, based on the maintenance rule. He would input that reliability into his PRA. He would do his delta risk calculations.

If they came out okay, he would just have them -- he would monitor that reliability and make sure that he had an acceptable reliability.

Also, it would need to be acceptably high, that we could say that it is -- that the accident is mitigate.

If the PRA allowed him to have a reliability of 50 percent, well, we wouldn't accept that, because the Commission said, you had to mitigate this large accident, and we don't think 50/50 is a good enough chance to mitigate it.

So, I guess the minimum input reliability

could be around 90 or 95 percent for that and --

MEMBER STETKAR: It's interesting that the 14 days already chops out four percent of that 95 percent --

MR. DUDLEY: It does, right.

MEMBER STETKAR: -- availability, and it required equipment to be more reliable than most equipment is.

So, I had a question about the 14 days, but let's get back to the --

MEMBER CORRADINI: Well, that's okay, because what I'm trying to establish, and maybe it's just because I've got a bad memory and I didn't take good notes, four years ago, I'm trying to understand what changed from what we saw then, to what we have now, to modify, mollify, make us all feel better about the current version of the rule. That's what I'm trying to get, and I'm trying to get a historical perspective on that part.

MR. DINSMORE: This is Steve Dinsmore again. I think if I remember correctly, that the comment that the ACRS was making was, "Now, you're relying on this equipment, that's non-safety related. You should improve the monitoring of that equipment."

MEMBER CORRADINI: That's the essence of

what I remember of our concern.

MR. DINSMORE: Yes.

MEMBER CORRADINI: And staff's --

MR. DINSMORE: I guess we --

MEMBER CORRADINI: How did you address that concern?

MR. DINSMORE: Well --

CHAIRMAN SHACK: They're in the text books.

MR. DINSMORE: -- I guess we -- I can't quite remember how much was in the first rule that you guys were talking about. But the --

CHAIRMAN SHACK: Which version?

MR. DINSMORE: The monitoring, as Dick indicated, the monitoring would be in two areas, on the availability and reliability of that equipment.

It would be the maintenance rule, because we've figured out, in the interim, that this stuff will go in the maintenance rule, because of the way it's set up, and in the periodic update of the PRA.

I'm not entirely sure that we knew at the earlier point that the stuff had to go in the maintenance rule.

Once it goes in the maintenance rule, the maintenance rule has to establish criteria, based on the reliability, which they assume in their analyses

--

MEMBER CORRADINI: So, let me say it back to you, example-wise, and then I'll stop for a moment, and just think a bit.

So, you're saying if I had a PWR, and it just happen to have an additional charging pump, just happened to be there, right, and it was non-safety, and they wanted to take credit for it, for greater than TBS, they'd have to list it in the tech spec's, maintain -- give it -- verify -- show or follow the rule, that it had to be available in less than or equal to 14 days, if called upon, and it would have to have a reliability that the staff would judge to be acceptable and what you just said here, acceptable is on the range of 95 percent.

MR. DINSMORE: Well, the reliability would have to support the quantification that they use to show that the change in risk was acceptable.

MEMBER CORRADINI: Okay.

MEMBER STETKAR: In addition, right, the --

MR. DINSMORE: Whatever that happened to be.

MEMBER CORRADINI: Whatever that happened to be.

MR. DINSMORE: Yes.

MEMBER CORRADINI: Excuse me, okay, but I have it approximately right?

MR. DINSMORE: Yes, sir.

MEMBER CORRADINI: Okay.

MEMBER STETKAR: Before we get into numbers, though, the rule applies to new plants, and I know you're going to talk about new plants this afternoon, you said.

But the rule says that the equipment will be listed in the technical specifications. That seems inconsistent with the concept of RTNSS equipment for new plants, because RTNSS equipment is not listed in the technical specifications, is it?

It's tabulated somewhere else and it's availability is, you know -- it's in the maintenance rule program, that assures that --

MEMBER CORRADINI: Right, it's the --

MEMBER STETKAR: But what I'm worried about is that a new plant that comes in, pick a plant, has a non-safety related piece of equipment that they want to take credit for, for this particular issue.

Now, suddenly, that piece of equipment is in the tech spec's, only because of this rule, whereas, a large number of other safety related pieces of equipment, that are important to safety, are not in

the technical specifications. It doesn't seem --

MEMBER CORRADINI: You're talking for a new plant?

MEMBER STETKAR: For a new plant.

MEMBER CORRADINI: So, my question, mainly, just from an old plant, so, I yield, so that you can take his question, but I'm --

MEMBER STETKAR: You're the new plant guy, though.

MEMBER CORRADINI: Do you see the question?

MR. DUDLEY: Yes, but I think --

MEMBER STETKAR: I see a new plant --

MR. DUDLEY: I think it's kind of like --

MEMBER STETKAR: I see a new plant licensee, you know, who -- after I have a new plant and I decide that I want to adopt 50.46a, now, looking at something that says, "Well, if I do this, I'm going to have to put some non-safety related equipment in my technical specifications," which is a stronger licensing issue, than simply having it in my RTNSS list.

MR. DUDLEY: Well, 50.46a --

MEMBER STETKAR: Then that --

MR. DUDLEY: -- is a strange beast.

MEMBER STETKAR: It is.

MR. DUDLEY: It's a -- but if you say this is not a design basis accident, yet we will not let go of it, okay. We have regulations imposed on it.

MEMBER STETKAR: True.

MR. DUDLEY: So, we thought it was not necessarily inappropriate for the treatment in tech spec's to be different from other plants, where it's clear, design basis and non-design basis.

MEMBER STETKAR: I understand the dichotomy in current plants, because there's no way of actually listing that equipment.

But there is mechanism for the new plants.

MR. DUDLEY: I can't speak to RTNNS and I don't --

CHAIRMAN SHACK: RTNNS doesn't apply to all new plants, John.

MR. WILSON: That's one of the points I was trying to make, thank you. It doesn't apply to --

CHAIRMAN SHACK: DRAP does, though, DRAP does.

MR. WILSON: Right, and it's much different.

CHAIRMAN SHACK: It's a much different beast.

MR. WILSON: And remember, this is a

voluntary rule, so, someone is coming in, they're asking to take credit for this equipment, and we're saying, "Okay, in order to take credit, you need to put it in tech spec's," and I think that's appropriate.

MR. DUDLEY: Okay.

MEMBER RAY: Let me ask a question, not to the presenters, here, but to my colleagues, because I don't have this history, and I think you can answer it more easily.

The reliability of this equipment that we're talking about is referred to as input to the PRA.

I guess I'm struggling with, how do you derive a reliability under conditions as -- that's being credited, when those conditions haven't existed previously?

In other words, you're crediting the reliability of something that's not qualified for the condition that exists at the time that you're taking credit for it.

MR. DINSMORE: This is Steve Dinsmore from the PRA Branch.

We deal with that problem all the time. Effectively, the initial assumption is that the

equipment will operate in its design envelope. If you hit a -- if you realize that some equipment is going to help -- have to operate outside of its design envelope, you're suppose to evaluate that and determine that -- the effect of that, on the reliability.

It's a very difficult task, but it's not particularly special to this rule. It's a task that we deal with on a --

04 All right, well, I'm not constraining it to be on applicable here, but I'm still asking the question, take seismic, for example, how do you decide what the reliability of a non-seismically qualified component that you're relying upon?

Some people in this world think the most likely circumstance you're going to need it is an earthquake. How do you decide what the reliability is, in the event of an earthquake?

MR. DINSMORE: Well, the short answer is, seismic will be the bolts holding onto the wall. You'd have to go look at the fragility.

MEMBER RAY: But is that a requirement? That's what I'm trying to drive at.

MR. DINSMORE: Yes, it is a requirement. How well it's always fulfilled, depends on how

important it's perceived to be. But it is a general requirement, yes.

MEMBER RAY: So, as part of the PRA, you can't simply credit something, because you choose to credit it. You have to show that it's recently accredited, I guess --

MEMBER CORRADINI: Based on some analysis.

MEMBER RAY: What?

MEMBER CORRADINI: Based on some analysis.

MEMBER RAY: Okay, because that's the first time I've heard that.

MR. DINSMORE: Thankfully, it doesn't come up that often. Usually, they're within the design envelope, but yes, we're aware of that and if it comes up, it has to be dealt with, explicitly.

CHAIRMAN SHACK: Now, even within the design envelope, you might have your questions. I mean, we have our famous containment accident pressure discussion, where you assume that the containment leak rates that you get are based along normal operating experience, and then we suddenly go to an accident situation and the --

MEMBER RAY: That's why I was saying the question in your direction, Bill, was because exactly that point, is, I was thinking back on that, I'll call

it an anomaly or conundrum, whatever it is.

Okay, I mean, I've gotten an answer. I'll just file it away and see how it works out.

But I'm just, I guess, a skeptic, that the --

CHAIRMAN SHACK: But I think it's sort of Steve's answer, is, that as long as the thing that has got the design margin, you assume it's operating in a reasonably reliable sort of condition.

MEMBER RAY: Yes, well, like you said, it's the bolts -- if it falls off on the floor, well, I'm not sure. But anyway --

MEMBER STETKAR: So, talking about tech spec's, I got my philosophical out of the way. I wanted to ask about the 14 days.

I understand that that's evolved from a zero initial --

MR. DUDLEY: It went from zero to seven, to 14.

MEMBER STETKAR: Okay, what's the basis for the 14 days?

MR. DUDLEY: Steve Dinsmore will respond.

MR. DINSMORE: I don't have an answer to that. Give me a second.

MEMBER CORRADINI: You might as well stop

--

MEMBER STETKAR: While he's looking for the answer let me --

MEMBER CORRADINI: We have an empty chair, until Rob gets here.

MEMBER STETKAR: Let me express my concern a little bit more. Fourteen days, if I assume a 90 percent plant availability factor, is about four percent of the time.

MEMBER CORRADINI: Ninety-six percent.

MEMBER STETKAR: Now, if the presumption is that my breaks beyond the transition break size occur at the frequency of 10 to minus five per year, which seems to be an embedded assumption in all of this, and I have my mitigation equipment out of service for four percent of the time, that gives me a core damage frequency of four times 10 to the minus seven, per year. That's what it is, just from the tech spec's.

I mean, assuming the equipment operates perfectly, whenever it's not out of service, assuming that people could, in deed, leave the stuff out of service for up to 14 days, in any calendar year, that's a core damage frequency, if that transition break size and above LOCA frequency occurs at 10 to the minus five, per year, four times 10 to the minus

seven, per year.

Now, perhaps, the thought was that that might be acceptable for the current fleet of plants, because that's somewhere in this nebulous range between minimal increases and small increases, and the question is, is it acceptable for new plants?

CHAIRMAN SHACK: Minimal and very small.

MEMBER STETKAR: I'm sorry, minimal and very small. I get my teeny, tiny, itsy-bitsy numbers confused.

(Off the record comments.)

MEMBER STETKAR: Between minimal and very small, I stand corrected. Is that four times 10 to the minus seven considered acceptable for new plants, because this, again, is an arbitrary 14 day number.

CHAIRMAN SHACK: Well, it's applied to everybody.

MEMBER STETKAR: Regardless of the plant.

MR. DINSMORE: Your calculation is valid. We went the other way, though. We took, for example, if you -- in the SRP's, if you have external events that are less frequent than 10 to the minus seven, per year, you don't have to mitigate them.

And so, if you take 10 to the minus five and not 10 to the minus seven, you get four days --

MEMBER STETKAR: And that's --

MR. DINSMORE: -- and then we took the AOT acceptance guidelines, the conditional to integral core damage probabilities of five times 10 to the minus seven.

So, if we were going to give an AOT to this, which meets those guidelines, how long would that be?

MEMBER STETKAR: If this --

MR. DINSMORE: This is a -- there is no good guidance, I agree.

MEMBER STETKAR: Okay, if this is a risk informed transition, why don't we just require that the equipment is in the tech spec's and we require the licensee to provide justification for the risk informed allowed outage time?

MR. DINSMORE: We added that to the rule. You will be pleased.

MEMBER STETKAR: Well, that's an `or', 14 days or --

CHAIRMAN SHACK: You want him to defend it.

MEMBER STETKAR: No, the implication is, or longer.

MR. DINSMORE: Well, the rule now says 14 days --

MEMBER STETKAR: Fourteen days is always acceptable.

MR. DINSMORE: Yes.

MEMBER STETKAR: Yes, that's what the rule says. My concern --

MEMBER CORRADINI: Your concern --

MEMBER STETKAR: My point is, require them to do the analysis --

MEMBER CORRADINI: And justify a number.

MEMBER STETKAR: -- and justify a number, which could be 14, or for a particular site, could be three.

MEMBER CORRADINI: And if I just might --

MEMBER STETKAR: Well, for a new plant, might be a day and a half.

MEMBER CORRADINI: What I guess I'm hearing from John is a consistent argument from this one in the 30 minutes, which is, if the licensee wants to do this, they should do the analysis to say, what is an acceptable number, rather than giving them, excuse my English, an `out' at 30 minutes and 14 days. That's what I get.

MEMBER STETKAR: That's exactly right. A specific -- now, this is in the rule, though. The 30 minutes is not in the rule. The 30 minutes is --

MEMBER CORRADINI: Is in the guide.

MEMBER STETKAR: Is in the guide --

MEMBER CORRADINI: Right.

MEMBER STETKAR: -- guidance, explanatory in the --

MEMBER CORRADINI: So, your question is, why is it in the --

MEMBER STETKAR: The 14 days is in the rule.

MEMBER CORRADINI: Okay.

MEMBER STETKAR: That is a rule.

MEMBER CORRADINI: Okay.

MR. DINSMORE: Okay, this is Steve Dinsmore, again. Yes, it would -- the problem is, that this is loss of function. We don't have a lot of experience, risk informing loss of functions. We have a lot of experience risk informing degraded functions.

There is a WCAP that just got approved a couple of months ago, that deals with loss of functions, and the methodology is pretty complicated and we haven't really implemented it yet, and the short answer is, we didn't want to put something in the rule, which we didn't really know how to do, which is require them to do this.

So, what's in the rule is something that

we consider to be generically acceptable, or if they can do it and get around to it and demonstrate it acceptably, we'll take what they can come up with.

But we didn't want to just stick in there, "Well, you've got to do this thing that we don't know how you're going to do," because it will just kind of stop the process, if we get hung up on reviewing this evaluation of theirs.

There would be no option to -- we'd have to accept something, whereas, if the 14 days is in there, we can always say, "Well, we could do the 14 days, if you want to move forward and you can continue to work on these other processes."

So, it was mainly the fact that we didn't know how to do this.

MEMBER STETKAR: Okay, Steve, I'm -- I understand that you don't know how to do it, but for a new plant, pick a design that comes in and says, "Today, my total core damage frequency, without implementing 50.46a, from all initiating events, during all modes of operation, is on the order of five times 10 to the minus eight event, per year."

I am now going to implement 50.46a, and I will follow the rule and I can allow my mitigation equipment to be out of service for up to 14 days a

year. Could my core damage frequency from beyond design basis LOCAs, now be four times 10 to the minus seven, per year, or something on the order of -- like, an order of magnitude, larger than the sum of everything else, together, and that's okay?

MR. DINSMORE: Well, what you're pointing out is, we hadn't -- this applicability to new reactors is kind of a late blooming flower, and we --

MEMBER STETKAR: But there was issue today, it's the rule, and it says it applies for new reactors.

MR. DINSMORE: Well, then even a 10 to the minus seven increase is still fairly small, even for new reactors, even if it does down right there.

MEMBER STETKAR: There, you're talking about risk metrics for new reactors --

MR. DINSMORE: Yes.

MEMBER STETKAR: -- which is an unresolved issue right now, thought. Philosophically, how those numbers are going to apply for new reactors is -- is still questionable.

MR. DINSMORE: I tend to run the other direction, when we talk about new reactors. So, if anybody wants to chime in.

MEMBER STETKAR: Well, but I -- the whole

point of my brining this up is, that we need to think about new reactors because the rule explicitly does apply for new reactors.

If we haven't thought about new reactors, we should say that the rule does not apply for new reactors yet, because we haven't thought about them.

MR. DUDLEY: I guess what we could offer is to try to get a spokesperson that's a little more familiar with some of these issues here, even if --

CHAIRMAN SHACK: But I actually think Steve is right, until you settle on your risk metrics for changes in new reactors, I don't see how you can address this for new reactors.

MEMBER STETKAR: Well, but implicitly, you are.

CHAIRMAN SHACK: And that's still further discussion.

MEMBER STETKAR: You are, I mean, implicitly, the problem is --

CHAIRMAN SHACK: Your point is, that you're -- I mean -- that, being inconsistent with the risk metrics that you developed for new reactors.

MEMBER STETKAR: Right, and my whole point is, do we need to --

CHAIRMAN SHACK: And I'm not suggesting

that --

MEMBER STETKAR: -- create that issue --

CHAIRMAN SHACK: -- we have any further discussion at this point, to clarify that issue. I mean, that's simply a conundrum that --

MR. DUDLEY: How close are we to making that decision on the new reactor -- is that a --

MEMBER STETKAR: Far.

MR. DUDLEY: -- hypothetical question?

MEMBER STETKAR: That is -- it's not a hypothetical question. Any answer would be hypothetical.

MR. DUDLEY: All right, so, we're -- it's not like it could get resolved before the Commission has taken action on this --

CHAIRMAN SHACK: Well, no, I think the direction that it's going, which is that you're not going to allow a significant increase, but -- would say that this is --

MEMBER STETKAR: Well, but defining what is a significant increase --

CHAIRMAN SHACK: But since you haven't defined what a significant increase is --

MEMBER STETKAR: -- is the whole crux of the matter.

CHAIRMAN SHACK: -- is the --

MEMBER STETKAR: That's the whole problem, and that is --

CHAIRMAN SHACK: Is a problem.

MEMBER STETKAR: That decision is a long way out.

CHAIRMAN SHACK: Well, and 50.46a time space, it may be like, tomorrow.

MEMBER RAY: Bill, we're done with that?

MR. DUDLEY: Do you want us to try to get some additional staff, or do you think it's --

CHAIRMAN SHACK: Yes, I think that -- you know, that could well be an issue that could appear in ACRS letter. So, I think, you know, that would -- any clarification on that would be helpful.

MR. DUDLEY: Okay, we'll see what we can do, with a particular person.

To respond to that, Don Dube is out of the -- is not available today. He's --

CHAIRMAN SHACK: We were -- we know him.

MR. DUDLEY: So, that's a shame.

CHAIRMAN SHACK: He's smart, yes. Smart move.

MR. DINSMORE: Steve, just to make sure that I fully understand the issue, if -- the last 14

days per year is about four times 10 to the minus seven and four times 10 to the minus seven might be a substantial risk increase for non-reactors, and it's built into the rules --

MEMBER STETKAR: And it's built into the rule.

MR. DINSMORE: Okay.

MEMBER STETKAR: That's the problem.

MR. DINSMORE: Okay.

MEMBER STETKAR: It's built into the rule, so that a licensee can always fall back to the rule and say, "You allowed me to do this," regardless of whatever the risk increase is.

MR. DINSMORE: Okay, thank you.

MEMBER STETKAR: Sure.

MR. DUDLEY: We'll try to get someone from new reactors to speak to that, later today.

MEMBER RAY: Okay, Bill, again, I'm trying to get clarity in my own mind, and just trying to figure out if we -- there is some carve-out here in the example of a containment, that you refer to as -- is what I'm trying to apply here.

Take, credit for off-site power, how one evaluates the fragility of off-site power and its availability, it seems to me, to be a bridge too far,

being involved in that for non-nuclear reasons, for a long time.

You assume off-site power is going to be lost, just for the kind of events that are associated with a seismic event.

Is that what we've done here, or is it just not relevant to the analysis, because we're somehow, excluding seismically induced LOCAs or what?

MR. DUDLEY: The loss of off-site power is considered, under 50.46a, as part of the risk input. In other words, when they do the delta risk analysis of the --

MEMBER RAY: Exactly, but how do you --

MR. DUDLEY: And they'd have to come up with a reasonable probability for that, based on the plant and the grid, in that situation, and they'd have to calculate delta risk associated with, and you compare it to the acceptance criteria, and I guess that's how --

MEMBER RAY: I would think that's really --

CHAIRMAN SHACK: But I think as you do the seismic PRA, you would assume off-site power is gone--

MEMBER RAY: Oh, it's gone?

CHAIRMAN SHACK: -- which is probability one --

MEMBER RAY: Yes.

CHAIRMAN SHACK: -- but the probability that the seismic event is going to produce a large break LOCA, is very low.

MEMBER RAY: Well, okay, but we are, never the less, talking about doing the analysis here, and it's listed up there `credit for off-site power'.

And I'm just trying to figure out, because the -- in my world, anyway, that a seismic event is the most likely cause, however remote, it's the most likely cause of a large break LOCA, and how you would ever credit off-site power in that event, is beyond me.

MEMBER STETKAR: I think the key is, you can take credit for off-site power. You do not need -- you're not instructed to assume that it is available, is the difference.

MEMBER RAY: Well, I know that -- well, okay, John, but again, I'm asking, is it really plausible that somebody is going to due an analysis of the grid and say, "I've got some probability that I can take credit for off-site power."

MEMBER STETKAR: Not for the seismic events, but there are other ways of getting these LOCAs.

MEMBER RAY: Of course, yes, no, I understand, it's not the only cause, it's just the most likely cause, in my world.

Okay, I mean, you can -- maybe there are other more likely causes, you can think of, stress corrosion cracking, I don't know.

But in any event, it's certainly the source of the largest -- the source of the largest loading on the system, force loading, that you can imagine, and so, I just wanted to figure out, is it really the case, that you would -- and I think the answer is `yes', that you would not give credit for off-site power, unless it could be shown that it had some -- you said you'd reject anything below 50 percent, or you wouldn't take it.

Credit for something that only had a 50/50 probability of operating, that's what you said, sure as heck isn't going to be a 50/50 chance of operating an off-site grid under those circumstance.

MR. DUDLEY: What size earthquake are you -- you know, maybe --

MEMBER RAY: Any size you want to --

MR. DUDLEY: -- we might need to differ the seismic discussion, until Rob Tregoning gets here.

MEMBER RAY: That's what happened last

time. We don't talk about seismic, because it's --

MR. DUDLEY: I know, I can't.

MEMBER RAY: -- too hard.

MR. DUDLEY: Well, Rob will be glad to do that, I think, and he'll be here shortly.

MEMBER STETKAR: Let's do that, because I had a couple of other seismic questions, too, Harold, and I think --

MR. DUDLEY: Yes.

MEMBER STETKAR: -- this is all integrated.

MEMBER RAY: People tend to treat it as outside the bounds of what we think about here, but it's not.

MEMBER ARMIJO: THE implicit assumption here is that it's -- you can't have a seismic event big enough to break a large -- the large pipe, greater than the transition break size, because if you have -- if you can do that, you can't count on any of this.

MR. COLLINS: This is Steve Collins. I believe that is the assumption in the rule, I believe that's what was stated.

If a seismic analysis -- that the licensee is required to perform, when they want to apply for 50.46a, and the purpose of that analysis is to demonstrate that the probability of a seismically

induced large break LOCA is small enough, that we basically don't have to provide protection for it.

MEMBER RAY: Well, it's --

MR. COLLINS: That's basically it.

MEMBER STETKAR: No, it's less than about 10 to the minus fifth, per year.

MEMBER RAY: Well, okay, so, it is off the table, then.

MEMBER ARMIJO: That is the way I read it, yes, or else, you can't justify --

CHAIRMAN SHACK: It's off the table for this analysis.

MEMBER ARMIJO: Right.

CHAIRMAN SHACK: If you're looking at the seismic PRA, then you know, this -- the whole design base -- I mean, I look at it from a seismic analysis.

A design basis analysis doesn't tell me anything about -- an earthquake big enough to bust the large pipe is going to bust so much stuff --

MEMBER ARMIJO: That is my point.

MEMBER RAY: But there isn't anything big enough to burst -- to bust a large pipe.

CHAIRMAN SHACK: Well, but there has to be treated in a different space than this design basis accident, because again, you know, single failures

don't mean anything. You know, all sorts of stuff has failed.

MEMBER RAY: All right, well, I don't argue about it. I just want to try and be clear. So --

CHAIRMAN SHACK: But I think --

MEMBER RAY: -- this excludes seismic events, then? Is that right?

MR. COLLINS: Except from the risk perspective.

CHAIRMAN SHACK: Except from the risk perspective.

MR. COLLINS: It's just from the risk perspective.

MEMBER RAY: Well, that's the risk perspective that I'm talking about, I think, when I ask you, how you treat the reliability of the off-site power, that's listed up there.

MR. COLLINS: I believe we would assume that a seismic event that's large enough to break large pipe, you're not going to have any credit for off-site power.

MEMBER RAY: That's the right answer.

MR. COLLINS: That's for sure.

MEMBER RAY: I'll stop. I still don't understand how we're dealing with this, but it sounds

like it's a threshold kind of a thing, and then we ignore it after that.

MR. DINSMORE: This is Steve Dinsmore. To some extent, I think that's correct. If the contribution of the seismic event is such a low frequency to start with, we don't need to include it in the change in risk calculation, because it's not going to --

MEMBER RAY: Talk to the people at Diablo Canyon and see what they think.

MR. DINSMORE: I'm not sure they're in that group of stuff that --

MEMBER RAY: You could take this -- you never know.

MR. DINSMORE: Yes.

MR. DUDLEY: We did a generic seismic study and a licensed -- Diablo Canyon wanted to implement 50.46a, they'd have to show how they were bounded by that generic study.

Likely, they wouldn't be able to show that, and so, this rule would not permit them to go forward.

MEMBER RAY: Okay, I don't want to belabor it, then. I guess I understand it.

MEMBER STETKAR: Since you mention the

generic study, is it better to talk to Rob this afternoon -- whenever he shows up?

MR. DUDLEY: It certainly is.

MEMBER STETKAR: I'll wait.

MR. DUDLEY: That's the limitation on my knowledge of that study, right there.

Okay, let's move on. Slide 11, the transition break size is -- for PWRs, it's the largest attached pipe to the main coolant piping, and that's generally -- that's most always the pressurizer surge line, with an inside diameter of around 11 or 12 inches.

For BWRs, the TBS is the largest attached, either feed-water or residual heat removal line inside containment, a diameter on the order of 22 or 24 inches.

MEMBER STETKAR: Now, would that be --

MEMBER ARMIJO: Excuse me, for the operating plants, does that include or exclude research lights, the big --

MR. DUDLEY: That would --

MEMBER ARMIJO: -- 28 inches are --

MR. DUDLEY: -- would exclude it, yes. That would not be the research line. It would be an attached pipe to the larger.

MEMBER CORRADINI: The research line, meaning like a jet pump, is that what you --

MEMBER ARMIJO: No, the big --

MR. DUDLEY: The ring header.

MEMBER CORRADINI: The ring header?

MR. DUDLEY: It would not be that.

MEMBER ARMIJO: Wouldn't be that?

MR. DUDLEY: Right.

MEMBER ARMIJO: But it would be --

MR. DUDLEY: If you assume that broke, you -- that's your double-ended guillotine break.

MEMBER ARMIJO: Yes, right.

MR. DUDLEY: So, yes, it's smaller than that.

MEMBER ARMIJO: The feed-water line, which is also a very big pipe, and the main steam are included?

MR. DUDLEY: We didn't include the steam line. That was -- is too large.

MEMBER ARMIJO: Is it large?

MR. DUDLEY: It's too large.

MEMBER CORRADINI: My interpretation, from the last time I looked at it, is the feed-water line is what we're really, primarily --

CHAIRMAN SHACK: Feed-water and RHR, yes.

MEMBER CORRADINI: Right.

MEMBER ARMIJO: Feed-water and RHR, and then in the PWRs, it's not the hot-leg, cold-leg, or pressurizer light?

MEMBER STETKAR: It's the pressurizer line --

MEMBER CORRADINI: It's a pressurizer --

CHAIRMAN SHACK: It's a pressurizer surge line, typically.

MEMBER ARMIJO: Okay.

MR. DUDLEY: Right.

MEMBER ARMIJO: Okay.

MR. DUDLEY: When a plant initially wants to convert to Section 50.46a, they'll have to demonstrate the applicability of the two generic studies we used to justify 50.46a, the expert elicitation report, with the LOCA break frequency versus size curves and the applicability of the seismic study.

The applicant will also have to evaluate the leak detection capability at their facility, to make sure it meets the enhanced approach described in our recent Revision 1, May 2008 revision to Reg Guide 1.45.

And if the licensee wants to have a self-

approval process, where the licensee could make some changes enabled by 50.46a, on their own, without the NRC reviewing the change, the licensee would have to describe that process that they propose to use, to the NRC, and we would have to review and approve that process.

MEMBER ARMIJO: If the -- someone wanted to challenge the elicitation report, let's say, BWR says, "I don't think our big feed-water line is -- should be included," is that -- can they do that and do they have -- you know, simply say, "The elicitation report, and here is our reasons why it doesn't apply to us," or is that a settled issue?

MR. DUDLEY: We don't have provisions for that. I mean, I guess if they wanted to do that, they could request an exemption from the rule.

MEMBER CORRADINI: But they would have to show a reduction in frequent -- I would assume, they'd have to do a plant specific --

MEMBER ARMIJO: Well, you know, that --

MR. DUDLEY: That's a unique situation that is --

MEMBER ARMIJO: Yes, they'd look at the --

MR. DUDLEY: -- and if they had one, they might justify an exemption.

MEMBER ARMIJO: Yes, okay. So, they'd basically be challenging the results of the elicitation?

MR. DUDLEY: Yes, the rule does not provide for that. The only way --

MEMBER ARMIJO: Is the exemption.

MR. DUDLEY: -- you could deal with that, if there were some anomalous situation, would be via an exemption.

MEMBER ARMIJO: Okay.

MR. DUDLEY: Okay, for plant changes enabled by 50.46a, we expect that they will likely be included in a licensee's initial application to implement the rule, but they could also be submitted later, if the licensee had additional margin to use.

For enabled changes, a licensee would have to re-analyze their ECCS performance for each of the two regions, using the NRC -- using NRC approved methods. That's one of the changes, at one time, we didn't require NRC approval for the -- beyond TBS analysis methods.

And for any non-safety equipment credited in the tech spec -- credited for breaks larger than the TBS, as we've said before, it would have to be listed in the tech spec's and we would -- they would

have to provide on-site power to that, not necessarily safety grade or an automatic connection.

And in addition to meeting the ECCS requirements, any enabled changes have to meet a risk acceptance review. So, the licensee would have to demonstrate, by a risk-informed analysis, that the risk-informed acceptance criteria are met.

MEMBER CORRADINI: And then for operate -- just to get back to -- so, I'm clear, for operating plants, that would be in the -- get all the adjectives wrong, but the 10 to the minus seven, 10 to the minus six --

MR. DUDLEY: Right here.

MEMBER CORRADINI: Okay.

MR. DUDLEY: Next slide.

MEMBER CORRADINI: Thank you.

MR. DUDLEY: Risk-informed acceptance criteria --

MEMBER CORRADINI: Thank you, thank you.

MR. DUDLEY: -- are here.

CHAIRMAN SHACK: As long as you know what very small and minimal are.

MEMBER CORRADINI: I don't remember the numbers. I don't remember the adjectives.

PARTICIPANT: You have to be a member of

the club.

MR. DUDLEY: For changes submitted to the NRC for review and approval, cumulative risk increase could not exceed very small. Very small, we consider that to be a core damage frequency of less than 10 to the minus six, and a large early release frequency of 10 to the minus seven.

For self --

CHAIRMAN SHACK: Again, this raises John's question, again, about consistency with risk metrics for new reactors.

MEMBER STETKAR: Exactly, and another thing that had to -- again, this is back into the supplementary information.

Statements that say, a very small risk increase is independent of the plants' base-line risk, unless there are indications that a plants' risk is exceptionally high, and the same criteria can be used for all licensees, one size fits all.

So, if I have even an operating plant, that for some reason, I have made several modifications to, based on a very progressive risk assessment program, and my core damage frequency for the operating plant is rather small, because one size fits all and it doesn't make any difference what my

base-line risk is, I can accept a 10 to the minus increase in risk, even for an operating plant, which doesn't quite seem to be a risk-informed frame work.

CHAIRMAN SHACK: Risk-informed, not risk-based.

MEMBER STETKAR: Well, I have real problems with this -- a specific number applies equally well to everybody, kind of approach.

I mean, if that is a Commission directive and a Commission policy, then we don't need to worry about risk metrics for new reactors and it's not clear, what this whole risk-informed frame work, for example under 174, means.

MR. DINSMORE: This is Steven Dinsmore. I do have a little bit of an answer for new reactors, on this one.

New reactors added this requirement, that there's not a -- I can't remember the words, because I'm not -- it's in my slide, somewhere.

But new reactors added this requirement, that for applicants representing certified design, we added the criteria that changes will not result in a significant decrease in the level of safety otherwise provided.

So, for new reactors, I'm unsure if you're

-- if you are opining that these things are too big or too small.

MEMBER STETKAR: You know, honestly, Steve, I don't have any -- other than the 14 days, in the rule, I couldn't find any words in the rule, itself, that I had problems with.

I had a question about why that paragraph was put -- was called out specifically for new reactors, because the other paragraphs in that same section of the rule seem to apply the same -- you know, consistent, sort of back-stops. It's the --

MR. DINSMORE: Well, exactly, to address your issue --

MEMBER STETKAR: Right.

MR. DINSMORE: -- about the new reactors, that's very small.

MEMBER STETKAR: The concern that I have is that people will read the rule and they will read the published supplementary information as a technical basis for interpretation of the rule, and the supplementary information has all of these numbers floating around in it, and the interpretation that the concept of a very small or minimal increase in the risk is independent of the plants' base-line risk, that it's an absolute -- you know, it is implicitly a

Commission determination of an absolute value, rather than a relative value.

So, it's in the supplemental information, where all of the numbers are specified, and trying to define one size fits all for existing reactors and new reactors, in a very explicit numerical sense.

MR. DINSMORE: Well, the very small was provided in the Commission SRM.

MEMBER STETKAR: The numbers or the --

MR. DINSMORE: No, the word `very small', but other than that --

MEMBER STETKAR: Very small, I have no problem with --

MR. DINSMORE: But it has a --

MEMBER STETKAR: -- very small, because --

MR. DINSMORE: -- specific meaning.

MEMBER STETKAR: Because if I'm an applicant, I have to justify to you, what is very small.

MR. DINSMORE: Well, but we need to tell them what we've -- normally, we would indicate to them, well --

MEMBER STETKAR: We've got Reg Guide 1.174 to do that.

MR. DINSMORE: Right, and there's a number

in there for very small. Minimal --

MEMBER STETKAR: For existing plants, that's right.

MR. DINSMORE: For existing plants, yes, and then this addition here, about if you've got a new reactor, you also can't substantially decrease the level of safety inherent in the design.

That was, to partly address your concern, that they might have really, really small CDFs, and that this very small could be huge.

So, that was put in there to at least give us a way to address that, but the minimal is a fixed number, is -- the minimal is simply a guideline for when they need to make a submittal or not.

MEMBER STETKAR: Okay, so, I'm a new reactor that has a total core damage frequency from everything, that's five times 10 to the minus eight, and because this change results in an increase of 10 to the minus seven, that's minimal and I don't even have to submit?

MR. DINSMORE: Well, I'd have to look at how -- where the -- the acceptance criteria on this, added criteria, and that the changes will not result in a significant decrease in the level of safety.

That might not be applicable to self-

approval, in which case, you -- that would be something we'd have to look at.

MEMBER STETKAR: That comes under, I believe, the submittals that require approval, I think. I'd have to go through that.

MR. DINSMORE: I seem to remember, that's where it comes in, but --

MEMBER STETKAR: So, implicitly, the 10 to the minus seven would apply, I mean, if somebody said, "It's 10 to the minus seven, I don't need to submit this for approval," --

MR. DINSMORE: Okay, we can check and see where the minimal --

MR. DUDLEY: If a new reactor applied for a self-approval process, it seems like we could, at that point, design into the self-approval process, a screen or a --

MEMBER STETKAR: Well, except for the fact, the rule sort of specifies the rules for that self-approval process, already. I mean, it seems a bit sticky.

MR. DUDLEY: I guess it could be.

CHAIRMAN SHACK: I mean, it seems, you do have an out, but you've also got stuff built into the rule, and it's not clear that the two aren't --

MR. DUDLEY: Yes, it's --

CHAIRMAN SHACK: -- contradictory.

MR. DUDLEY: We have applies to the self-approval process.

CHAIRMAN SHACK: Right, right.

MR. DUDLEY: I guess, you're right.

MEMBER STETKAR: But that's -- yes, I mean, in principle, I could see somebody getting into trouble because they have made a determination that they don't need to -- that they can self-approve a change, because it's, you know, 6.999 times 10 to the minus eighth, and they come in for another change, for approval, and you say, "Oh, ghee, you know, 2.03 times 10 to the minus seven is not acceptable," because that's not a very small -- or it's not a --

MR. DUDLEY: Minimal.

MEMBER STETKAR: -- significant -- that is a significant decrease in the level of safety.

MR. DINSMORE: I agree in principle, that could happen, yes. Well, we'll -- we can go back, and again, this is -- you're helping us, like, identify --

MEMBER STETKAR: It's most -- most of the problems are -- when I start thinking about this, philosophical stuff, keep the specific numbers out of

any discussion of anything, is the new reactors, and not necessarily in the words of the rule, other than the 14 days.

The words of the rule, I could think about new reactors and they're appropriately vague. They say significant decreases, very small, things like that, which can be left to interpretation. I mean, regulatory guidance, you know.

But if people will read this and take the supplementary information as explicit interpretation of the Commissions' technical basis for what's in the rule, and use that, you know, in the sense of regulatory guidance, then it gets real troublesome, when you look at new reactors.

And so, you might -- we'll probably discuss that in the --

MEMBER ARMIJO: Well, but are --

MEMBER STETKAR: There might be a way out, in terms of being less specific --

MEMBER ARMIJO: It sounds to me --

MEMBER STETKAR: -- in the supplemental information --

MEMBER ARMIJO: -- John, are you saying that the risk metrics issue for new reactors ought to be settled first, before you --

MEMBER STETKAR: Well, but the practice --

MEMBER ARMIJO: -- but putting in numbers, in this rule?

MEMBER STETKAR: In principle, yes, I am, but in practice, it won't. I think there's a lot of reason to get this rule finished and published, for many reasons that will affect --

MEMBER ARMIJO: But that's not the -- but it's --

MEMBER STETKAR: -- but other than that --

MEMBER ARMIJO: That was there --

MEMBER CORRADINI: I think -- I thought Sam's question was, is if this did not apply to new reactors, then you would rather have the risk metrics for new reactors settled, before it applies.

MEMBER STETKAR: If it either didn't apply for new reactors, or if it applied for new reactors and the explanatory information was less numerically precise, such that regulatory guidance for operating reactors would interpret what is very small, minimal, acceptable, when people do their submittals, and regulatory guidance to be developed at some future date, when the risk metrics stuff is sorted out for the new reactors, would then apply for the new reactors, which you know, obviously, none of the new

reactors currently in the DCD or COL phase have indicated that they're going to apply this.

So, you know, we're -- in practical terms, we're talking about a few years in the future, where any new plant licensee might --

MR. DUDLEY: We'll try to get a new reactor spokesperson that can perhaps, address that.

MEMBER STETKAR: Yes.

MEMBER ARMIJO: But when this is issued, this is mandatory for new reactors, isn't it, or is it still optional?

MEMBER STETKAR: No, it's optional. This is optional. So, you know, the way I see it, Sam, is none of the current new reactor designs, either in the DCD or anything that we've seen from the COL, have indicated that they might adopt this.

This one design that has indicated, they might adopt risk-informed tech spec's, but even that's --

MEMBER ARMIJO: Not likely to use it.

MEMBER STETKAR: -- even that's a bit questionable, right now.

So, the way that this would play out is that, you know, a COL would be issued and at that point, a particular licensee could decide to adopt

this, but in practice, that's years in the future.

Hopefully, the risk metrics issue would be a little bit more clear by then.

MEMBER ARMIJO: But let's say, they were -- the risk metrics issue was resolved, but they're still in compatibility, a de facto in compatibility, in an existing rule.

Somebody could go back and say, "I'm going to use the 14 day rule," and even though you were really tough on the risk metrics, this is a -- it's a way out, and that's your issue.

MEMBER STETKAR: It's my issue.

MEMBER ARMIJO: My question is, should -- seeing that possibility, shouldn't we sort of put things in order for new reactors, risk metrics first, and adoption of this rule for new reactors, issuing --

MEMBER STETKAR: I mean, that's --

MEMBER ARMIJO: You know, it's a new reactors question.

CHAIRMAN SHACK: I mean, that is a question for the staff. I mean, is it important to have -- I mean, the new reactors is sort of a new addition to this rule. Is it important to have that, as a piece of the rule now?

MEMBER CORRADINI: Right, that's kind of

the question I was thinking, how important is it to have it at this point?

MEMBER STETKAR: The problem is, it would require -- as the rule is written right now, would require quite a bit of editing to pull that out. In terms of career builders, it depends on the staff.

MR. DUDLEY: We're already covered with ours, it doesn't matter.

MR. COLLINS: There were some -- we've had -- we've been debating the issue of whether or not this rule should be applied to new reactors, over the past month or so, internally, and the staff is kind of split, on whether it should or not.

So, I'm not surprised that we're hearing this debate.

There's also the perspective of, if you look at passive plants, the rule doesn't do much for passive plants. I mean, a single failure doesn't help a passive plant.

CHAIRMAN SHACK: I can only think of one new reactors that would probably be really interested in this.

MR. COLLINS: Yes, it's hard to imagine --

CHAIRMAN SHACK: Well, yes.

CHAIRMAN SHACK: Two.

MR. DUDLEY: Turning to the risk acceptance criteria, for self-approved changes, the risk increase has to be no more than minimal. Minimal is an order of magnitude lower than very small, 10 to the minus seven CDF or 10 to the minus eight, and for self-approved changes, the change process in Section 50.59 would have to be satisfied, also, for the licensee to make this change on his own.

And for all risk-informed changes, they would all -- whether submitted or self-approved, the changes would have to meet the -- the defense-in-depth criteria would have to be adequate, defense-in-depth would have to be maintained. Safety margins would still have to be adequate and a monitoring program would need to be implemented to make sure that over time, that PRA stay consistent with the actual conditions in the plant.

Here are the operational requirements for a facility who has been approved to implement 50.46a.

First of all, all future plant changes that are made at that plant, whether enabled by 50.46a or not, will have to be reviewed to make sure they don't invalidate the applicability of the two generic studies.

We saw no way around that. So, the

licensee's change process will have to have a step in it, that causes them to check this evaluation.

The licensee should maintain the sufficiently sensitive leak detection. This is for all piping larger than the TBS, and there is also an operational restriction in 50.46a.

If the licensee is operating in some equipment configuration, where breaks larger than the TBS cannot be shown to be mitigated and meet the acceptance criteria, operation in that condition is limited to a short time. A short time, as we discussed earlier, is either less than or equal to 14 days, every 12-month period or some other alternative period approved by the NRC.

Throughout the life of the plant, the licensee must keep its PRA methods to be of sufficient scope and quality, and the licensee has to periodically confirm that the cumulative risk increase under 50.46a does not exceed very small, and he would do this by updating the PRA at a frequency no less than at least once every four years.

MEMBER STETKAR: Rich, and this will probably go to Steve, the once every four years, is there other guidance for periodicity of PRA updates, and in particular, I'm thinking about new reactors.

I couldn't find it, but I ran out of steam. I know they have to update it, but --

MR. DINSMORE: Yes, sir, it comes from new reactors, exactly, 50.70 --

MEMBER STETKAR: Four years is consistent with them?

MR. DINSMORE: Four years is consistent.

MEMBER STETKAR: Okay, I seem to remember three years, but I couldn't find it on the --

PARTICIPANT: That's the basis to put it in the --

MEMBER STETKAR: That's fine, as long as it's consistent.

MEMBER CORRADINI: Is the update in the rule or in the guidance?

MR. DINSMORE: The update is in the rule.

MEMBER STETKAR: The update is in the rule, the number rule.

MR. DINSMORE: Four years is in the rule, yes.

MEMBER STETKAR: Okay.

MEMBER ABDEL-KHALIK: Presumably, people would want to take advantage of this rule, if there was a benefit in it for them, and the question is, have you sort of done an inventory, to see how many

plants are large break limited?

PARTICIPANT: Do you want to guess at that?

MR. DUDLEY: I think the answer is, no, we haven't done a review.

MR. LANDRY: We haven't -- this is Ralph Landry, from the staff.

We have not done a formal inventory, but informally, if a -- that's just looking at PWRs, if a plant does share LOCA analyze to large break, and they're able to fill the down-comer, on the degraded ECC, according to the current regulation, adding additional water from this version of the regulation, would do them no good. Any additional water would just go right out the break.

So, the only plants that could benefit from this, as far as ECC relief, would be those which cannot fill the down-comer on the present degraded configuration, or degraded requirement for the configuration on the ECC.

As a rough guess, I'd say that would be less than half.

MR. DUDLEY: Approximately half, yes.

MR. LANDRY: Yes, so, we're not talking about everybody is just going to come in and grab a whole lot of margin, by switching over, because right

now, some can't -- really, realistic analysis, can't gain much.

MEMBER ABDEL-KHALIK: Well, I'm just concerned that we're going to be flooded with power upgrade requests.

MR. LANDRY: Well, we talked about this back and forth, quite a bit, a couple of times, with this rule, in front of the Committee, and if a plant has already converted from Appendix K to the best estimate or realistic LOCA, now, they've taken away a lot of that margin, that's in Appendix K, and then they went to add -- and it pushed that limit, also.

Now, they want to add a power upgrade, on top of it, and if you look at Appendix -- at 50.46a, and having all ECC available, as the way to get that margin back, so that they can have power upgrade, what I just said previously, if they can fill their down-comer's on the degraded ECC, they don't get relief from this, because the extra water doesn't do any good.

So, they can't look at this as a way to justify power upgrade.

MEMBER ABDEL-KHALIK: Yes, I understand the mechanics of the process. I'm just --

MR. LANDRY: I know, we're going --

MEMBER ABDEL-KHALIK: I want to see where --

MR. LANDRY: -- back and forth on this and --

MEMBER ABDEL-KHALIK: -- what the impact of this rule will be.

MR. DUDLEY: Okay, next, Steven Downy will talk about applying 50.46a to new reactor design. So, we'll probably just continue that discussion, since we've already started it.

MR. DOWNEY: Good morning, everybody. Once again, I'm Steve Downy. I'm staff on the Office of New Reactors and I'll be providing an overview of the application of the 50.46a rule to new reactor designs, which will include the history of new reactors in the rule and a summary of the changes.

Now, in the earlier days of the rule making activities, new reactors were essentially excluded from the original rule.

As documented in the staff requirements, memoranda for SECY 04-0037, the staff was directed to consider how future plants would be covered by the rule. However, the rule making for future plants was to be pursued on a separate and slower path from that of existing plants.

Now, the Commissions' position didn't change during the development of the original proposed rule, however, it was decided that the issue of whether or not the rule should be available to new reactors was one that warranted some public comment, and public comment was solicited to that issue in the Federal Register notice on the original proposed rule, which was published in November 2005.

So, in 2006, we received a number of public comments on the applicability to new reactor designs, and all the commenters agreed that the rule should be applicable. Two comments, that I'll share with you, that were of particular interest to the staff, were provided by Framatome and the Westinghouse Owners Group (WOG).

Framatome commented that the 50.46a rule should be available to nuclear power plants, licensed after the publication of the rule, that are of similar design to the current generation of operating PWRs and BWRs.

They also stated that advanced LWR designs, previously certified under design certification review, and in the pre-review process, all fit into this category and can realize the benefits of the 50.46a rule.

However, for the rule to apply to a new design, the NRC must first make a determination that the design is similar to currently operating LWRs.

The Westinghouse Owners Group stated that future PWRs and BWRs operating with pressures and temperatures, and materials that are similar to operating LWRs should be able to implement the 50.46a rule, because there is no technical reason that new plants should not have to meet outdated rules, to which current operating plants can opt out.

So, taking into account these comments, the staff eventually agreed and began internal discussions to identify potential issues in applying to rule to new plants, as we've had some today.

Some of those issues include how to incorporate evolutionary and -- versus advanced plants into the rule, and how the rule would apply to each, and also, defining similarity of new plants to the current operating fleet. Next slide.

From that discussion, which we stated on the last bullet, the rule -- the supplemental proposed rule was modified to include new reactor designs.

Now, from the time of the supplement proposed rule to the current final rule, there were no significant public comments. The staff did make some

changes to the applicability statements, to make sure they were correct and also, to clarify interaction of the 50.59 process and the 52.98 finality requirements.

Now, finally, to summarize the changes of the rule, and the applicability to new reactors, as described in the final rule, it was decided that a new plant can voluntarily implement the 50.46a rule, if they first determined that they were similar in design and operation to the current operating fleet.

In addition to determining similarity, they would have to propose a transition break size and provide a justification for that transition break size.

In addressing similarity to the current operating plants, the new plant, applicant, licensee, etcetera, would have to address design, construction and fabrication, operational factors that include, but are not limited to piping, piping materials of construction, service and operation of programs, piping design, control of age-related degradation and also, they would have to identify the plant specific attributes that may increase LOCA frequencies compared to those of NUREG 1829, once all that -- in addition to the information required in the rule for current operating plants.

Once they've submitted all of their information, the NRC would do a design specific review. These were, of course, the transition break size and everything, as proposed on a plant specific basis, and the staff would approve similarity and would approve the proposed transition break size, and that's it. Any questions?

MEMBER ARMIJO: Let me ask a question about the similarity for the new plants, that we're currently looking at, the ESBWR, the passive plants.

Would they meet the similarity test? Has the staff considered that already and said, "Yes, they apply."

MR. DOWNEY: Well, the staff --

MEMBER ARMIJO: I'm not sure they get any benefit out of it, but --

MR. DOWNEY: Yes, that's --

MR. DUDLEY: Well, if you'd benefit, they wouldn't apply.

MEMBER ARMIJO: No, I meant -- I'm just asking the question, let's assume that there might be some benefit. I don't think there is, but have they already said, "Hey, look, the guys are already going through the certification process," they would fit, they'd be acceptable.

MR. DOWNEY: Well, we didn't make the decision for the -- I guess, that they're already similar, but we did look in -- we did have a lot of discussions on the issue of whether or not the rule would benefit those passive designs.

But even saying that, the rule is still voluntary. So, we don't want to determine whether or not the licensee would benefit, for the licensee.

MEMBER ARMIJO: Sure, understood.

MR. DOWNEY: And still, they were able to come in and apply for the rule.

MEMBER ARMIJO: But there is nothing that would -- that you currently see, would prevent, let's say, an ESBWR or an AP-1000, from --

MR. DOWNEY: No, the short answer.

MR. COLLINS: Yes, this is Tim Collins. I think we've kind of left the door open. If these advanced plants want to try to convince us that they're similar, we're willing to listen to their arguments. We haven't made a decision that they're similar. We haven't made a decision that dissimilar, at this point in time.

MEMBER ARMIJO: Okay.

MR. COLLINS: We've kind of put some words in the FRN, to leave that --

MEMBER RAY: But their base-line risk is dissimilar, right? I mean, that's the whole -- and I guess, isn't that your point, John, that you're taking something with a dissimilar base-line risk and you're allowing changes, or you're allowing the criteria to apply, that are the same are you apply to existing plants?

MEMBER STETKAR: Yes, I mean, my problem is with the numbers, it's not with the philosophy. Well, and there's another way to --

MEMBER RAY: That's what I'm trying to say --

MEMBER STETKAR: But in terms of -- if, you know -- my -- some of the new plant designs, like AP1000, want to take credit for this.

A note slide 17, Westinghouse Owners Group apparently was interested in making sure that there was applicability to new reactors.

So, I suspect they're interested in AP1000.

MEMBER RAY: But isn't this the conversation we had earlier, in which this issue of whether or not a change in risk should be independent of what the base-line --

MEMBER STETKAR: That's a metric. It has

-- it's a different issue, compared to whether or not the basic principles of this rule would apply to a new --

MEMBER RAY: I'm trying to talk about the metric. Isn't that --

CHAIRMAN SHACK: Yes, well, but there is the separate issue of whether the argument over the frequency or large break LOCAs --

MEMBER RAY: Right.

CHAIRMAN SHACK: -- is going to change. You know, that's the material, the pressure, the environment.

MEMBER RAY: Seismic qualification --

CHAIRMAN SHACK: Those probably -- the answer, to me, seems pretty much, yes. You know, the real issue here, and I'm sure that Framatome and WOG weren't thinking about it at the time, is whether the metrics are going to change, but I --

I mean, again, you would have to go through with a review, just to make sure that there was nothing in the materials --

MEMBER STETKAR: You know, I think the take-away from this might be to read through the rule, you know, the supplemental information and the guidance, I think, needs to be very carefully thought

about, and to read through the rule itself, pretty carefully, to see if there are any traps in the wording of the rule or specific numbers that are in the rule, that might cause significant problems, when you're taking about that -- those metrics, measuring the change in risk and the acceptability of that change, for those new reactors.

MEMBER RAY: Yes, that's exactly what I'm talking about. That is the issue that you're talking about, isn't it? I'm just trying to make sure I understand it.

MEMBER STETKAR: Yes.

MEMBER RAY: Yes, because we had this debate. I was strongly of the opinion, something with a low risk that was licensed that way shouldn't be permitted to make a big change --

MEMBER STETKAR: Right, that's --

MEMBER RAY: -- because other plants did.

MEMBER STETKAR: That's part of the philosophical issue of all of the risk metrics for new reactors, which hasn't been resolved.

I mean, you know, it's -- everything is on the table there.

MEMBER RAY: We have a position, we have a resolved position, in that context, which was?

MEMBER STETKAR: We wrote a letter.

MEMBER RAY: All right, fair enough.

MEMBER STETKAR: We wrote a letter.

MEMBER RAY: But in any event, I just want to be clear. I have a resolved position, in my own mind, which is, you license one thing, you keep it that way, you don't make it something else.

MEMBER STETKAR: We wrote a letter. That's probably a different topic.

CHAIRMAN SHACK: Joe, do you have heartburn with the 14 days --

MEMBER STETKAR: Yes.

CHAIRMAN SHACK: -- for current reactors?

MEMBER STETKAR: In principle, I do, you know, as a philosophical issue.

CHAIRMAN SHACK: In principle?

MEMBER STETKAR: As a philosophical issue, I do.

CHAIRMAN SHACK: But as a practical matter?

MEMBER STETKAR: I'd have to think about that, in practice, Bill, because it's in this -- you're evening up a margin, a fairly -- you know, about half the margin from minimal to very small, if you want to think of it that way, and depending on, you know, if, in the limit, people leave the stuff out

for 14 days, that would imply to achieve the not very small change, you need to have pretty doggone reliable equipment.

Now, if -- you know, if the risk assessment and the reliability programs can show that, but that also would be a very plant -- it could be a very, very plant specific type of reliability.

You might need a reliability of .999 for component, you know, `x' at Plant A, but only .997, for example, at Plant B, same equipment, only because of this 14 day/one size fits all.

CHAIRMAN SHACK: Now, of course, coming back to this, you know, what non-safety equipment would you consider, you know, it --

MEMBER STETKAR: Well, it could even be safety equipment.

CHAIRMAN SHACK: Yes.

MEMBER STETKAR: And if they could justify taking it -- you know, somebody mentioned taking accumulators out of service, if you could justify it, but the --

CHAIRMAN SHACK: Yes, but all I'm saying is that you need all of this for everything, up to the TBS, and that's not going to leave a whole lot of equipment.

Now, I could see this, as we go towards the GSI and the 30 day cooling, where in fact, you might want to bring non-safety systems in that aren't being considered at all now, in 50.46 space, but could come in, in the long-term cooling.

I mean, that's where I would see non-safety systems, as probably entering the picture, at least for PWRs, would be trying to resolve a 191 kind of concern. If you were ever going to apply this to --

MEMBER STETKAR: Yes, that could -- yes, yes.

CHAIRMAN SHACK: -- to one hand -- well, I think that's the only way you're going to ever get around 191, with this kind of rule, is to bring in some sort of non-safety type of argument, and there, it would be.

MEMBER ABDEL-KHALIK: But you might want to be -- you might be able to designate one train of LPSI, for example, is non-safety related.

MEMBER STETKAR: Probably not LPSI, but you've still got to meet single failure for small LOCAs. You want to think -- maybe LOCA -- you know, you want to think LOCA, and as Bill said, long-term core cooling under 191 type stuff, perhaps.

But you know, I was thinking, you know, accumulators, or you know, low pressure pump trains in a plant that has pretty high capacity, medium pressure pumps, PWRs, for example, you know, like a -- I don't want to say plant maintenance, but certain plant designs, I could see --

MEMBER ABDEL-KHALIK: Possibilities.

MEMBER STETKAR: -- possibilities for that traditional safety related equipment to be designated non-safety or --

MEMBER ABDEL-KHALIK: But unless there is sort of a big difference between that time period, 14 days, and the time that people are currently allowed --

MEMBER STETKAR: Well, people are not ■-

MEMBER ABDEL-KHALIK: -- to have this --

MEMBER STETKAR: You see, the different -- philosophically, is, people are never allowed to remove complete mitigation capability from service.

MEMBER ABDEL-KHALIK: Right.

MEMBER STETKAR: And this allows you to take out complete mitigation capability, for 14 days.

This would be the equivalent, on an existing plant, of removing all of your high pressure injection systems and low pressure injection systems

from service, for 14 days, yes.

So, it's different. You need to think about it in that context, that --

MEMBER ABDEL-KHALIK: But a subset of that is required to meet breaks, to satisfy requirements for break less than the transition --

MEMBER STETKAR: Yes, I mean, it's -- so, it's trying to find out --

MEMBER ABDEL-KHALIK: It's a whole other ■-

MEMBER STETKAR: If we suppose individual plants, what they're going to try to do and can take credit for.

CHAIRMAN SHACK: I don't think there's going to be a whole lot of flexibility. You know, it's certainly possible on a plant-by-plant basis, but it's --

MEMBER STETKAR: The problem is --

CHAIRMAN SHACK: The break size was six inches --

MEMBER ABDEL-KHALIK: Then it would have made --

CHAIRMAN SHACK: -- it would have made a difference, but where it's currently sitting now ■-

MEMBER STETKAR: I just have -- you know, you asked the original question, for existing plants,

philosophically, I have a problem with it, because it's the specific number, one size fits all, sort of, approach.

In practice, you know, I don't know whether it would --

MR. COLLINS: And part of it is coming up with that number, as well. I mean, we interacted with the industry on this.

Originally, it was zero, but then all of the sudden, we find out we got a pump that doesn't work. What do we do at this point, right?

And so, it was an argument back and forth. They initially said, "Well, give us 30 days," and we thought, "Well, what do you need 30 days for," I mean, you've got to be able to fix anything in what amount, and we kind of settled on seven first, and then, well, 14, if it's a real tough problem.

MEMBER STETKAR: Well, but I'm looking for the -- okay, but that's sort of the ad hoc negotiations that we had, you know, 40 years ago in licensing, and we sort of know more now.

You know, I could take a number, like 72 hours would miraculously give me 1E to the minus seven, which is minimal, if I presume a 1E to the minus five, which seems to be the nominal frequency

that people are assigning for this.

So, why not 72 hours, if you're saying, minimal? You know, that's a number that's sort of prevalent in standard technical specifications for, you know, a lot of things, where you get down to margins for single failures, for example.

So, I'm looking for, you know, if 14 days, if there is a distinct, technical rational behind it, what is it, and if there isn't one, you know, that applies --

MR. COLLINS: It's a combination of practical and technical, if you will.

CHAIRMAN SHACK: I mean, there is no quod erat demonstrandum here, that's for sure.

MR. COLLINS: That's true.

MEMBER STETKAR: But is it -- you know, it's not an unreasonable number, based on risk considerations and --

MEMBER STETKAR: It's between minimal and very small.

CHAIRMAN SHACK: And you know, I think there is no way that -- TBS has been chosen, 10 to the minus five is a fairly conservative estimate, of the break frequency.

MEMBER STETKAR: Probably until you get

into when were -- seismic stuff, and then I would argue that this whole analysis is -- I'm not necessarily going to presume fragilities of equipment or structures, but we'll take more about seismic, I think.

CHAIRMAN SHACK: Yes, seismic is not going to go away. We're waiting for Rob.

Let's see, where are we at in schedule? Ten o'clock, right? Let's take a break until 10:25 a.m.

(Whereupon, the above-entitled matter went off the record at approximately 10:10 a.m. and resumed at approximately 10:30 a.m.)

CHAIRMAN SHACK: Let's come back into session. It is back to you, Rob. They've been pushing everything off, until you got here.

MR. TREGONING: I'll answer all the hard questions. I am Rob Tregoning, from staff. We'll be talking about the transition break size and plant specific demonstration of applicability, of that transition break size.

So, we're going to be dealing with the rule, but I'm going to step back a little bit, especially in the beginning, and talk about the technical basis.

I know I've presented this many, many times, in front of this Committee, but I think it's always good to have a refresher, especially if there is any new members that haven't heard this a plethora of times. So, I do want to give a brief overview.

So, if I outline the presentation, there is really -- there is really three distinct parts. I'll be providing a brief summary of the research conducted, which supported the development of the TBS. So, that's the first part.

The second part is going to focus on this regulatory guide that's been developed and is actually out as a draft now, for public comment, and I'm going to talk about the motivations and objectives behind that Reg Guide, talk about the scope, philosophy and frame work, and then touch very briefly on the principle consideration to that draft.

We don't have much time today, to get into -- in a lot of detail, all the technical aspects of the Reg Guide, but I do want to touch on the main themes and concepts and evaluations that are part of that Reg Guide, and then if we want to get into more detail, that's certainly something we can do. They'll be certainly more opportunities for that, at other meetings, and then finally, I want to provide the

status and schedule for the Reg Guide.

So, that's part two of the talk, and then part three, I'm going to go back and focus on the rule, and actually public comments that we got back, related to these areas, both on TBS selection and the plant specific demonstration of applicability to TBS. I wanted to cover the bases first, so that when we get to the public comments, everyone -- you all will be equally informed, as to the rationale and justification behind that responses that we gave for those public comments, because they're based on, again, a lot of the developmental work that I'll talk about early in the presentation.

So, let me, again, part one, a little brief overview on the technical basis supporting the transition break size. There were two NUREGS, as I'm sure you're aware, NUREG 1829 and 1903 that were developed as part of this technical basis.

And the development resulted from Commission direction that we got back in 2002. It said the staff should provide a comprehensive LOCA failure analysis that's realistically conservative, which was, of course, the buzz word back in those days, with appropriate margins for uncertainty, and we were further directed to use expert elicitation to

converge service data and PFM results.

So, we went off and did this study and the study has broader applicability, at least certainly in my opinion, both these studies have broader applicability than 50.46a, but within 50.46a, they have specific applications.

NUREG 1829 was used to provide part of the technical basis for selecting the transition break size, and then 1903, once that transition break size was selected, was more of a confirmatory study, which said, "Okay, let me look at risk associated with seismically induced breaks greater than the TBS, and make sure that that risk is less than the risk that was used as the basis for selecting the TBS to begin with."

So, what we wanted was, we wanted to ensure that the seismic contribution to risk associated with the greater, or at least the frequency of greater than TBS events, was, you know, less than and significantly less, I'll say about an order of magnitude less, inherent risk in just a TBS occurring, or greater than TBS break occurring, due to normal operations.

So, I just have a slide or so each, on 1829 and then one on 1903.

As I mentioned previously, we used elicitation, expert elicitation, to estimate generic, and I want to emphasize the word `generic', PWR and BWR passive system LOCA frequencies, that were mainly associated with material degradation.

So, the fact that they were generic really called us, or required us to develop this Reg Guide analysis that I'm going to be talking about later.

The way the elicitation worked is, we had about, I think it was 12 panelists. They provided quantitative estimates, supported by qualitative rationale, and we did the elicitation's all individually, and they were broken up. We just didn't ask them for LOCA frequencies, we had several underlying technical issues that we wanted them to address and then by accumulating or summating all these individual issues, we arrived at LOCA frequencies that were developed for each individual expert, which we then combined, to get our final estimation.

As you might expect, we had generally, very good agreement among the experts on qualitative LOCA contributing factors, but there was large individual uncertainty and panel variability in the quantitative estimates.

Of course, there's on surprise here. We're trying to estimate things that hadn't happened by and large. Certainly, the small break LOCAs, we had some operating experience for, but as we got into medium and larger break LOCAs, these are things that haven't happened.

So, it's not surprising there would be individual uncertainty, and panel variability that was large, when providing estimates for those types of events.

As I mentioned we determined group, or developed group results, by aggregating the individual panels estimates, and we reflected the uncertainty in the individual estimates, in the 5th and 95th percentiles, about their median estimates, and then we reflected the panel variability and confidence bounds about each of those percentiles.

NUREG 1829, which again, we discussed here, many, many times, was published in April 2008.

Now, 1903, NUREG 1903, as I mentioned, this was a confirmatory seismic -- study, to look at the effects of seismically induced loads, and the likelihood of those contributing to LOCAs.

That was a multi-prong study. We looked at prior PRAs, the IEEEs. We looked at seismic

studies. We looked at earthquake experience, both U.S. and internationally, to provide really, a baseline and a way to benchmark the analysis that we were doing.

So, we tried to accumulate all the Op-E that we could find, as well as all the PRA insights we could get, related to seismic events, and then what we did, we actually did a direct analysis of piping failure, associated with rare seismic events. We wanted to focus on the rare events, these 10 to the minus 5th and 10 to the minus 6th, per year events, because that was the risk metric that we had based the TBS on to begin with.

So, what we wanted to demonstrate, or what we wanted to explore, was how robust those systems were to these types of rare earthquakes.

So, these are much bigger earthquake, obviously, than an SSC type of an event that would be required, as part of the design basis analysis.

And again, we were focusing, we wanted to look at beyond TBS events. So, we really only focused on piping systems larger, with diameters larger than the TBS, because the TBS is in the 14 to 28 inch range. That made our study a lot easier, than if it were in the four to six inch range. So, it really

helped define the scope in that way.

The other thing we looked at is, we did a much more smaller study and scope, to look at large component support failures that may lead to piping failure, and these are what are called indirect piping failures, or indirectly induced seismic events.

The results we got in a nutshell, could be categorized for three different types of failures, unflawed piping. So, if you had piping that was pristine and not degraded and didn't contain flaws, based on, again, not just the studies that we did, not just the direct analysis, but also, much of the operating experience that we had with some of these bigger earthquakes. The failure frequency for those pipes are expected to much lower than 10 to the minus 5th. So, there's really no issue with unflawed piping.

The challenges, if any, start to become when you start to postulate degradation or flaws in piping, and the thing that we did was -- in this study, is, we said, "All right, what type of critical flaw do I need to get my failure probability up to about 10 to the minus six?"

Okay, so, I still want to make sure that I stay below the risk metrics that was used to

determine the TBS, and what you found, even there, for these big pipes, is that you need pretty big flaws and I think, pretty big is ■- is, I think, generous.

In reality, I think you need very large flaws, in order to cause failure within these systems, and by very large flaws, I'm -- you know, I'm thinking long circumferential flaws that span about 80 percent of the pipe diameter and go anywhere from 25 to 30 percent deep.

So, these are very large continuous flaws, and they would be -- we have no service experience with finding anything that big in operating plants or, you know.

We've had flaws that are big in plants that -- that were in production. It had been uncovered, either during hydro-tests or other pre in-service inspection. I'm thinking of Duane Arnold, specifically, approached those sizes, but nothing -- nothing in an operating --

MEMBER ARMIJO: Fabrication flaws.

MR. TREGONING: Fabrication type flaws, yes, but we've never found anything even remotely that big.

CHAIRMAN SHACK: And Duane Arnold safe end was that.

MR. TREGONING: Right.

MEMBER CORRADINI: What did you say, Bill?

CHAIRMAN SHACK: Duane Arnold safe end would have met that criteria.

MR. TREGONING: That was the only -- right, and that's what I'm specifically talking about, that's the only flaw that I'm familiar with.

CHAIRMAN SHACK: That's an operating plant.

MR. TREGONING: That's an operating plant, but that flaw was found --

CHAIRMAN SHACK: It's a stress corrosion crack.

MR. TREGONING: No, Duane -- I'm thinking --

CHAIRMAN SHACK: In the safe end.

MR. TREGONING: I'm thinking of the -- I'm thinking the other pre-service -- that was a stress corrosion crack on top of the fabrication flaw. So, but you're right, that's the only flaw that even approaches that.

Indirect failures, like I mentioned, we did a much smaller study. We only looked at two cases. We looked at a Westinghouse and a CE plant, and for those two cases, they had a mean piping failure probability of approximately 10 to the minus

six per year. So, they also met our metrics.

CHAIRMAN SHACK: Now, EPRI did three cases.

MR. TREGONING: They did three -- all of three more cases.

CHAIRMAN SHACK: And they got six times 10 to the minus 6th, which starts to --

MR. TREGONING: For their biggest case.

CHAIRMAN SHACK: For their biggest. Well, if I get --

MEMBER ARMIJO: What was that event that would break --

CHAIRMAN SHACK: That's a pipe failure for an indirect --

MR. TREGONING: For the biggest area.

MEMBER ARMIJO: Something that will break some big, heavy component --

CHAIRMAN SHACK: Right.

MEMBER ARMIJO: -- and then it --

CHAIRMAN SHACK: Breaks the pipe.

MR. TREGONING: Usually, it's --

MEMBER ARMIJO: They're either --

MR. TREGONING: Usually, it's a component support.

CHAIRMAN SHACK: Yes.

MR. TREGONING: That's the usual --

CHAIRMAN SHACK: Steam generator support or something.

MR. TREGONING: The support breaks and it loads the piping, and then it causes the piping to fail.

So, you're right, it's a very limited study. I think there is good -- the fact that the NRC sponsored study and the EPRI sponsored study are in the same ballpark, gives us some comfort in that.

But there's certainly a realization that these type of indirect failure studies are incredibly plant specific and we've only -- and they're certainly going to be subject to a fair bit of uncertainty, and we've only looked at a fairly small number of cases.

I think because of that, when we talk about the rule, that's led to some of the limitations that we've imposed within the rule itself.

MEMBER STETKAR: Let me ask about that. The rule requires that when I apply this methodology, I must confirm that my seismic induced piping failure, your direct failures, are bounded by the results of NUREG 1903, is that right?

MR. TREGONING: Not necessarily bounded, but represented within the range of the results, provided in 1903.

MEMBER CORRADINI: Can you say that again? I'm sorry.

MR. TREGONING: Not necessarily -- you know, 1903 didn't provide just one result. It analyzed 26 different plants. So, there's a plethora of results, and it needs to be contained within that range of acceptable results, or meet the acceptable -- the acceptance criteria for, you know, the failure metric, you know, demonstrate, essentially, that your 10 to the minus six failure frequency, due to direct LOCA failure.

MEMBER STETKAR: Okay, but that could be large early release frequency also, from that seismic event.

MR. TREGONING: If you assume everything is one, you know, conditional events, or one for core damage and then one for LERF, sure.

MEMBER STETKAR: It's, if I break that big piping -- well, if it's flawed, maybe some of my other equipment will survive, but it's survivability for that size of acceleration is pretty small.

MR. TREGONING: A big earthquake, yes.

MEMBER STETKAR: That's a big earthquake. Let me ask you about the indirect failures, though.

If I'm going to apply 50.46a, as I

understand it, the rule does not require me to confirm the frequency of indirect failures, is that correct?

MR. TREGONING: That's correct.

MEMBER STETKAR: Why, if it's very, very plant specific and it might be much larger than the direct failures?

MR. TREGONING: Right, because we don't allow any changes to the seismic design basis within the rule, as a result, for any -- for any of the supporting components, and that's one of the reasons why that's explicitly in there.

MEMBER STETKAR: I understand that, and I think from the opposite direction. Here is the thought process.

Given the design of the plant, the piping systems, the structures, the supports and everything in the plant, I need to look at the design of my plant and confirm that there is nothing in the design of my piping that would make me more vulnerable to a higher frequency, lower acceleration seismic event, right, given the design?

MR. TREGONING: As part of their design basis requirements, they have to do that, correct.

MEMBER STETKAR: No, it's for this analysis, I need to look at the design of my piping

systems, for the direct failures, and confirm that there is nothing in my plant specific design that would make me more vulnerable to a higher frequency, lower acceleration earthquake, that would damage the large piping, is that right?

MR. TREGONING: That's correct.

MEMBER STETKAR: Okay.

MR. TREGONING: That is correct.

MEMBER STETKAR: Why am I not required to look at anything else in the structural part of my plant, and also confirm that?

MR. TREGONING: Because we're not allowing any changes or --

MEMBER STETKAR: I know, but my current design is not sufficient to meet a 10 to the minus -- you know, a five times 10 to the minus five earthquake. It is a --

MR. TREGONING: It's not your current design.

MEMBER STETKAR: -- to meet a 10 to the minus four.

MR. TREGONING: It's your current design, postulated that it's degraded, because you're --

MEMBER STETKAR: Not for structures.

MR. TREGONING: You're postulating --

MEMBER STETKAR: Indirect failures, indirect failures now, I'm talking about indirect failures.

MR. TREGONING: Indirect failures, you're right, you don't have to postulate.

MEMBER STETKAR: Right, but why am I not required to look at my current design of structures, components, supports and confirm that I am not vulnerable to a higher frequency, lower acceleration earthquake that would result in something failing, and then breaking a large pipe?

MR. TREGONING: Right, because we're not allowing changes to those support systems.

MEMBER STETKAR: My current design is based on a safe shut-down earthquake, which is a much higher frequency, much smaller acceleration earthquake.

MR. TREGONING: That's right, but the --

MEMBER STETKAR: Let's pick a .35g earthquake at 10 to minus four per year, and suppose a huge support fails, it is very likely to fail, at a .75g earthquake, at let's, four or five times 10 to the minus five per year.

I'm not required to go look for that. I meet my current design, seismic design, I'm fine, and yet, I'm not required to go look -- I'm required for

the piping, to go look to see if have some miraculously weak piping, but I'm not required to go look for that structure.

In other words, in principle, the requirement, if I had a pipe that was guaranteed to fail at .75g, at a frequency of five times 10 to the minus five, I would have to identify that, to comply with the rule, because I need to do a plant specific analysis, to show that my piping failure frequency is within the range. But I'm not required to do anything, for structures.

MR. TREGONING: But if -- Steve, did you want to say something, before I go on? You look like you wanted to.

MR. DINSMORE: Yes, maybe I could at least refine the difference, a little bit.

If you're -- you have big structural weaknesses and the whole plant was going to get into a lot of problems with a certain size earthquake, we wouldn't be interested -- well, we wouldn't deal with that here, because there wouldn't be any change in the risk, from any changes that you might make that are enabled by the rule.

If you were looking at one tank that might fall down and break a pipe, at a low frequency

earthquake, then, yes, then that's not currently covered. But it's a smalls subset of the potential weaknesses.

MEMBER STETKAR: I'm not going to try to presume every -- you know, I don't know about the design of every single plant out there. So, I'm not going to try to presume what might cause what failures, under what particular acceleration.

It's just curious to me that you're requiring a licensee to look at pipe, to make that confirmation, that in deed, they don't have any plant specific piping system vulnerabilities and you're not requiring them to do that same assessment for any of the structures.

Regardless of what the real seismic is, regardless -- because that's a different question. This is just a question of what vulnerabilities do I have at my particular plant, to seismic failures to give me information, whether I am within the basic constraints of those two NUREGs?

MR. TREGONING: But as part of that piping system, I mean, part of that analysis and part of the requirements to keep an updated PRA, right, they, through their inspection and analysis, determine degradation in their structural's. They would have to

reflect that.

MEMBER STETKAR: This is not -- nothing is degraded. I design the support, to meet a safe shut-down earthquake, with a little bit of margin.

MR. TREGONING: Right.

MEMBER STETKAR: And now, we're talking about earthquakes with accelerations that are far beyond the safe shut-down earthquake, two or three times.

MR. TREGONING: Yes.

MEMBER STETKAR: But still, at frequencies that are probably equal to or greater than 10 to the minus 5th per year.

So, I'm not looking at a degraded structure. I've been maintaining this structure. I designed it. I check it. It is a perfect structure, as far as I can tell from my licensing basis.

MR. TREGONING: You said there's a gap.

MEMBER STETKAR: But it's going to fail.

MR. TREGONING: Because it --

MEMBER STETKAR: At a frequency of higher than 10 to the minus five per year.

MR. TREGONING: But that risk is there now. They have that risk now, and we're not allowing changes related to that component of the risk, in this

rule. That risk of failure is there now.

MEMBER RAY: Well, yes, but you're designing for a large break LOCA now, aren't you?

MEMBER STETKAR: Yes.

MEMBER RAY: What we're talking about is changing that -- let's take reactor pump motor. It's a pretty damn big thing, sits on top of the reactor coolant pump valve, and it's held by --

MEMBER STETKAR: Stuff.

MEMBER RAY: -- snubbers that are embedded in the concrete, very much like what John said.

There's no way in the world those things are going to not fail, at some thing not terribly higher than the SSC. Those embedment's will pull right out.

And so, not looking at that, at all, in a PRA sense, seems weird.

MR. DINSMORE: May I propose, at least, that there might be some slight mitigation factor in the -- when -- in the rule, it says the licensee shall perform an evaluation to determine the effect of all plant facility changes and shall not implement any facility changes that would invalidate the evaluation performed pursuant to C.1.i, demonstrating the applicability of the licensee's facility of the

generic results in the two NUREGs.

So, what that means is, every time they make a change a the plant, they have to make sure that that change is not going to --

MEMBER STETKAR: But I'm not making a change. I'm not making a change.

MR. DINSMORE: Until they make a change, this rule doesn't --

MEMBER STETKAR: But I guess, maybe I -- maybe we're not -- I've been listening to John talk about this, but I guess, where -- I don't think -- there is some lapse of communication.

I think the way I view what John is asking is, is that if I have one earthquake level, that the whole system has been analyzed at, and it's perfectly fine, and now, there's another, lower frequency, but higher magnitude event, that it wasn't designed to, there is a gap there and indirect supports could cause an effect, and by changing -- by adopting this rule, you've opened up a risk that you haven't evaluated. That's what I think he said.

The fact that the risk hasn't changed, we haven't -- these numbers that are up here, are not risk numbers, they are frequency of pipe failure numbers, without any consideration of mitigation

systems.

MR. TREGONING: That's correct.

MEMBER STETKAR: The fact of the matter is, you have a 10 to the minus six earthquake, the mitigation, that is -- earthquakes, in this range of frequency, are part of your risk, already.

So, this argument that, I'm requiring somebody to look at the piping, but not at the structures, because, well, the structures are part of your risk already, well, the piping is part of your risk already. You just don't know what that risk is.

So, I don't -- and I have this argument with the fact that well, the structural failures are part of your risk already, because the pipe -- piping failures at the type of acceleration, are part of your risk already, and yet, you're requiring me, as an applicant, to look carefully at my piping, to make sure that it -- I do not have any plant specific vulnerabilities. I mean, that's the way I look at that requirement.

MR. TREGONING: Well, again, the thing I would argue is, right now, they're not required to go beyond their design basis, anyway.

So, if they had that earthquake that was just beyond their design basis now, they're not

required --

MEMBER STETKAR: That's right, but if I make the decision, if I'm an applicant that it's beneficial for me to adopt 50.46a, I have to follow a certain set of requirements to identify whether or not my particular plant is -- falls within the range of results from these two NUREGs, and there seems to be a gap.

I'm not required to look at those indirect failures, and I don't know why. I don't know why I'm not required to do that.

MEMBER RAY: And moreover --

MEMBER STETKAR: I can always decide that this is too much work for me to do and there's not enough benefit, and you know, I'm not going to do it, but as long as I decide that I'm going to do it, I don't understand why I'm not required to look at those indirect failures.

MR. TREGONING: Well, and the other thing with the piping too, the piping is expected to be -- you know, the piping fragility is certainly, over time, proven to be very robust, but the piping is subject to more harsher environment, so one would expect that that's going to -- if you're going to have degradation, it would likely show up in the piping --

MEMBER STETKAR: Corrosion happens.

MR. TREGONING: Corrosion happens, but again, the environments are much more severe, that the piping has to --

MEMBER RAY: Well, if that's our rationale, you know, I don't want to prolong this, but -- no, it's not right.

Look at 25 year old concrete embedment's, some time, and you know, they aren't the way they were to begin with, but the rad coolant pipe is pretty much the way it was.

So, I mean, you just have to -- I think the main point is, indirect failures, to exclude them, in a probabilistic sense like this, when they may, in fact, contribute to the failure frequency at much lower loadings, and therefore, higher probabilities, than the pipe itself would fail, seems, like I said, weird. I can't think of any other word.

MEMBER CORRADINI: Back to that technical term again.

MEMBER RAY: Yes.

MEMBER ABDEL-KHALIK: It's not an issue of evaluating a change. It's just an issue of determining whether or not --

MEMBER STETKAR: Well, we're not talking

about --

MEMBER ABDEL-KHALIK: -- a potential applicant is allowed to take advantage of this rule.

MEMBER STETKAR: The rule says that the applicant must demonstrate that there was, within the -- I don't have the words in front of me, here, but essentially, within the bounds, and I know it's a poor word, within the ranges of the results from these two NUREGs, with a notable exception, and that notable exception is these indirect failures, which at least the EPRI snapshot from admittedly, only three plants, showed that the indirect failures might not be significant, and in fact, they might be more significant than the direct failures.

I guess that limited -- that limited snapshot, with those results, especially because it was an industry analysis, might not give me a lot of confidence that there aren't other vulnerabilities on a plant specific basis.

MR. TREGONING: Well, I understand your point, but like I said, those vulnerabilities are there now, by and large.

CHAIRMAN SHACK: But you're not going to allow them to make changes, if they can't demonstrate that the failure rate is less than 10 to the minus

five.

So, whether they're there in the piping or in the indirect failure, you wouldn't let them make the change -- you know, he's got an indirect failure greater than 10 to the minus five, you're going to let him go off and do a power upgrade?

MR. TREGONING: No.

CHAIRMAN SHACK: But what in the rule stops him? He's not going to look at it. He doesn't have to demonstrate that his indirect failures are within the range, even if he's not going to make any chance -- change to his supports.

I mean, what he's going to come in and do with this rule is, upgrade his power. He's not going to change his supports. He's not going to change snubbers.

MR. TREGONING: If he came in on the power upgrades now, that's not an analysis that he's required to do.

CHAIRMAN SHACK: No, but you wouldn't let him make the power upgrade, because he's got to go through a 50.46.

MR. TREGONING: Right.

CHAIRMAN SHACK: And take the whole, large break.

MR. TREGONING: Again, if he didn't have to invoke 50.46, again, that issue potentially exists now, with any risk-informed change that somebody would want to come in and make.

CHAIRMAN SHACK: Well, the 50.46 --

MEMBER RAY: That's not a logical rebuttal of the point. The point is, you're using 50.46a, to do something. It's not argument to say, "Well, if you don't use 50.46a, then this vulnerability might still exist," you know.

CHAIRMAN SHACK: You made a huge effort to determine the pipe size at which we would get a 10 to the minus five failure, and yet, we seem somehow, reluctant to go off and look at the supports, to give us the same confidence.

MR. DINSMORE: This is Steven Dinsmore from the staff. Is there a methodology in these reports to look at indirect failures, like there was to look at -- I mean, you came up with a number. You must have had some methodology.

MR. TREGONING: Yes, 1903 used an approach, but it was basically -- it was based on earlier Lawrence Livermore studies.

So, it really was more of a, I'll say a Bayesian method, where they looked at the prior

studies and tried to update them, based on the latest seismic hazard information that they had, and it wasn't a true Bayesian analysis, but it's not like they redid those Lawrence Livermore studies. It was more of an update on the studies.

CHAIRMAN SHACK: Okay, so, they took the results from Lawrence Livermore and just used a new seismic hazard?

MR. TREGONING: By and large.

CHAIRMAN SHACK: Yes, okay, well, but even so, I mean, you still come up --

MR. TREGONING: By and large.

CHAIRMAN SHACK: -- with a number, as I said, you know, six times 10 to the minus six, when I've only looked at three plants --

MEMBER STETKAR: Well, and the assertion that it's very, very -- that, coupled with the fact that the assertion is, it's very, very plant specific.

CHAIRMAN SHACK: Right. I mean, I suppose we could look at the whole sample. We've got five plants of the highest of which is six times 10 to the minus six, and then we're going to draw a conclusion that everybody is below 10 to the minus five, and I'll bet if I looked at the scatter of results, I'd have a very hard time justifying that assumption.

MEMBER STETKAR: Also, were those studies done with the 2008 USGS seismic hazards?

CHAIRMAN SHACK: The EPRI ones were.

MR. TREGONING: Yes, the EPRI ones were, not the NRC ones.

MEMBER STETKAR: Not the NRC ones?

MR. TREGONING: NRC used the --

MEMBER STETKAR: Lawrence Livermore.

MR. TREGONING: Yes, the Lawrence Livermore.

MEMBER STETKAR: Okay, yes.

MR. TREGONING: That date back to the mid 90's, early 2000's, at this point, because that's all that we had publically available at the time.

So, we recognized that those were being updated, but we used what we had.

MEMBER STETKAR: I just didn't know whether the EPRI stuff has used that.

MR. TREGONING: Yes.

MEMBER STETKAR: I mean, that's good, in a sense that at least, they had the seismic hazard part of it, in those three plants.

MEMBER ABDEL-KHALIK: Was that viewed? Was this particular requirement viewed as a road block towards people sort of, exploring whether or not, take

advantage of this new rule?

MR. TREGONING: I don't know that I'd characterize it as a road block, but I think -- I think some of my own -- I'll just -- my own interpretation in this is, there is indirect failure analyses that you do, you know.

It's an incredibly challenging analysis and I don't even put a lot of credence on the numbers that were obtained, either from the NRC sponsored study or the EPRI studies, because I think there is a lot of uncertainty associated with that analysis.

I think there's much more certainty associated the flaw piping analysis and even the LOCA initiatives -- the LOCA initiating event frequencies, developed in 1829.

MEMBER RAY: I agree with you 100 percent.

MR. TREGONING: There's more of a basis on that.

MEMBER RAY: Those are the indirect -- the indirect failures are very hard to do, and there's a lot of uncertainty associated with them, but that's the reason why I'm concerned, is, colleagues will know -- I've said, before you ever start talking, you know.

MR. COLLINS: I think part of the reasoning was, though, if the contribution to the risk, whether

this rule is used or not, is no different, would you hold up going forward with this rule --

MEMBER STETKAR: Well, but it is different, because right now --

MEMBER ARMIJO: The benefit would only -- and you're only evaluating part of the risk, and I think that's really --

MR. COLLINS: They still need to --

MEMBER STETKAR: In principle, right now, you're covered by the requirement that the safety related systems must meet the design basis double-ended guillotine break, somewhat silent for the survivability for these earthquakes, but at least you have equipment installed --

MR. COLLINS: That qualification doesn't change, based on what the break size --

CHAIRMAN SHACK: I agree, you won't change the CDF --

MEMBER ARMIJO: But put that up to the --

CHAIRMAN SHACK: You won't change the CDF from this, but you would allow the guy to upgrade the power, which in fact, upgrades the risk.

You know, the frequency won't change, but perhaps, the remove system, mitigation systems for two weeks out of a year --

MR. COLLINS: Well, be careful, now, the seismically qualified systems are the safety rate systems, and you can't take them out anymore after this rule, than you could before.

You limit it by breaks below the TBS. Their availability is limited by the current tech spec requirement for breaks below the TBS.

CHAIRMAN SHACK: I mean, I will agree that you won't increase the CDF, but you will increase the risk, because you're allowed --

MR. COLLINS: But that's the fact that you have higher source --

CHAIRMAN SHACK: Higher source --

MEMBER RAY: I thought we said an accumulator, for example, could be taken out of service. That was an example given.

MEMBER STETKAR: I mean, in principle, somebody could take an accumulator out of service, in principle, if the accumulators are only required for beyond TBS, which is a safety --

MEMBER RAY: As long as they can satisfy --

MEMBER STETKAR: As long as they can satisfy all the --

MEMBER RAY: Because I had leaking check valves all the time. My accumulators are out of

service all the time.

MEMBER STETKAR: That's the thing I think about is --

MEMBER RAY: It's a big problem.

MEMBER STETKAR: -- you know, an example that I can throw up is, an existing safety related system that, I could have, you know, relaxation. Other ones, it's a little more difficult.

MR. DINSMORE: So, if I may, sitting back here, kind of not in the heat of the thing, but so, you guys are agreeable that the seismic study and the internal events, the study that the -- the checking they have to do, is reasonable for those two things? It's simply that the indirect failures, there was no -- there is no requirement in there for them to go check the indirect failures in a similar way, or not --

MEMBER STETKAR: I think that's right, Steve. I think the requirements on the -- if you want to make a change, you have to demonstrate that the delta risk -- there, you have to quantify it -- the CDF, you know, you have to know what the number is.

But this just says, "If I adopt -- if I make the decision to transition to 50.46a, there are certain things that I need to do, during that

transition process."

One is the piping analysis --

CHAIRMAN SHACK: But even the delta risk, he's not going to change his supports. I mean, you know, if he thinks his fragility of his supports now is -- you know, whatever it is, he's not going to change that.

MEMBER STETKAR: Whey do I have to look at the piping, then?

You know, my question is, everything I hear is, why do I have to look at my piping --

CHAIRMAN SHACK: No, what I'm arguing is that the risk analysis isn't going to capture anything in the support.

MEMBER STETKAR: Sure, theoretically, it is, if you do a seismic risk assessment. You have a fragility, for all of those equipments.

CHAIRMAN SHACK: Yes, but if you really believe that fragility, we could convolve that fragility right now, with the risk and we'd find that frequency.

MEMBER STETKAR: Yes, you could.

CHAIRMAN SHACK: You know. So, you know, the --

MEMBER CORRADINI: Was that hand gesture in

agreement?

MEMBER STETKAR: Yes, it was.

CHAIRMAN SHACK: Now, the thing is that we don't look at those fragilities, probably as hard as we would, if we were now using them as the basis for this rule, but that's still --

MEMBER CORRADINI: But you're in agreement with -- I mean, what Bill is saying, I mean, I guess that's -- I was just listening to you guys go back and forth.

What Bill is saying, though, is, you're not in disagreement. It's increasing the risk, it's not increasing the CDF.

By allowing this -- what we'll call this window, if somebody were to upgrade, you're increasing the risk, you're not increasing the CDF.

MEMBER STETKAR: If you're thinking about a power upgrade as --

CHAIRMAN SHACK: Now, John has some other things in mind.

MEMBER STETKAR: There are other things that could -- I'm not going to presuppose what a particular licensee --

MEMBER CORRADINI: Could do.

MEMBER STETKAR: -- at a particular

facility, with a particular seismic hazard and particular, you know, structural and piping fragilities might want to do, under this rule.

MEMBER CORRADINI: Right.

MEMBER STETKAR: I'm not going to try to presuppose that. The rule should apply to anything that I might want to think, that I might want to do, including power upgrades or, you know, relaxing criteria for systems or -- you know, I don't know.

MEMBER RAY: But let me, just give one piece of experience here.

Indirect failures, like you said, is a big deal. I've upgraded a seismic of an older plant, and man, you're walking into a mine field there.

But never the less, it's relevant to what we're saying, and therefore, I don't think it can be ignored, just because it's a big deal.

MEMBER STETKAR: The whole predication of this is that the frequency of a break beyond the transition break size is something less than 10 to the minus 5th per year, from all causes, together, right? That's sort of the fundamental basis of this.

If frequency of a break that's smaller than the transition break size -- I'm sorry, is larger than the transition break size, occurs more

frequently, due to some causes, then for my particular plant, I need to increase my transition break size, don't I, which can have implications.

MEMBER RAY: But you can't use the rule.

MEMBER STETKAR: Can't use the rule, or I have to justify one --

MEMBER RAY: One or the other.

MEMBER STETKAR: -- the plant specific -- you know, maybe I can still do what I want to do, with a larger transition break size --

MEMBER RAY: Or beef-up the --

MEMBER STETKAR: So, that I can get my transition break size to --

MEMBER RAY: Put a heavier snubber in or add a snubber, or something.

CHAIRMAN SHACK: I mean, it's the inconsistency, to go through the extended analysis to verify that the piping is okay, and yet, somehow, you know, bless the indirect failure, when every bit of evidence we have is that the indirect failure comes a whole lot closer to 10 to the minus five, than the direct failure does, even if we don't believe the numbers. I mean, we have to live with the numbers we've got.

I mean, if I look at unflawed piping, you

know, those numbers are --

MEMBER RAY: Yes, of course.

CHAIRMAN SHACK: -- pretty big, pretty small. The exponent is big, but --

MEMBER ARMIJO: Sort of like your dentist telling you your teeth are fine, but your gums have to go.

MEMBER CORRADINI: That's actually not so far off the mark, for what it's worth.

MEMBER ARMIJO: It just seems like, this rule could provide some benefit, but all the contributors to the risk aren't really being evaluated, just the piping, and if the support - failures of these supports are the same magnitude or larger, they should be evaluated, and I think that's really all I'm hearing.

MEMBER RAY: Yes, and that's not a change in criteria.

MEMBER ARMIJO: No, it's not a change in criteria.

MEMBER RAY: I don't see that as a barrier that we --

CHAIRMAN SHACK: No, I mean, the rule can go forward, all -- you know, the guidance just says that you verify the applicability of the unflawed,

flawed and indirect failures.

MEMBER RAY: Right, yes.

MEMBER STETKAR: I mean, somebody might -- you know, if someone finds a vulnerability, then they can come back and possibly make arguments, about --

MEMBER ARMIJO: Or change it.

MEMBER STETKAR: Or change it, you know, depending on what it is. Changing it might be expensive and difficult. But there's uncertainties in all of this, you know, the uncertainty is in the seismic hazards are huge, probably much larger, compared to the uncertainties in the fragilities of anything that you can come up with in a plant.

MR. TREGONING: I don't know, the fragility uncertainties can be fairly large, especially if you try to account for degradation. You have a lot of uncertainty, and that's really -- and when you get to numbers these low, that's what drives the analysis, it's the amount of uncertainty that you have.

So, I wouldn't try to minimize the uncertainty that you have there.

MEMBER STETKAR: I'll still say, in terms of frequency of failure, from things I've seen, the uncertainties in the fragilities may be large, but not

large, compared to the uncertainties in the seismic hazard -- the frequency of the seismic hazard.

I mean, just saying that you have a 10 to the minus five frequency of a, pick a number, you know, .75, .8, .9g earthquake, the uncertainty might be over three orders of magnitude, you know.

CHAIRMAN SHACK: When I put all the -- my frequency, I'm going to get both uncertainties.

MEMBER STETKAR: That's right, right.

MR. TREGONING: Put them all together.

MEMBER STETKAR: But the incremental effect, from the fragility, is a small effect on the overall uncertainty, than just saying, "I have large uncertainties on the fragility," that's true, you know, in the sense of the way most people think about uncertainty.

But in terms of its incremental contribution to the overall uncertainty on that, on that failure frequency, it's relatively small, compared to the seismic hazard.

PARTICIPANT: Typically.

MEMBER STETKAR: Fragilities vary between zero and one.

MR. TREGONING: Yes.

MEMBER STETKAR: So, you know, so, it can't

vary over, you know, several orders of magnitude.

MR. TREGONING: Yes, but -- I agree, but that's a big range --

MEMBER STETKAR: Zero is, but typical fragility analyses don't --

MR. TREGONING: Zero to one, that can be a big range.

MEMBER STETKAR: Yes, zero to -- it can, but people don't --

MR. COLLINS: Is the situation, though -- we talked about, there wouldn't be a change in CDF, there would only be a change in risk if there was a change in consequence, say, from a power upgrade.

CHAIRMAN SHACK: No, no, in John's example, you know, if you were allowed to take equipment out of service --

MEMBER STETKAR: I'm not going to presuppose what a particular applicant is going to do.

CHAIRMAN SHACK: I'm guessing, you know, in my head, I see the most likely event here, to be power upgrades, but that's not the only possible range of events, and in that case, the CDF might change.

MEMBER RAY: No, let me give you a different example. I had accumulators at my plant, doggone check valves would leak all the time, and

sometimes, we'd get in the LCO and have to shut down and go in and fix the check valves.

Well, depending on what the outcome is here, it would affect that. Now, it may not mean I could ignore the accumulators forever, but I --

MEMBER STETKAR: Well, I could take them out for a couple of weeks, or the --

MEMBER RAY: Yes.

MEMBER STETKAR: Maybe, even with a couple of them out for a couple of weeks --

MEMBER RAY: For as long as I could, yes, that's for sure, not 72 hours, which is what I had to live with.

CHAIRMAN SHACK: No, but could you handle the TBS, this size TBS without accumulators at your plant?

MEMBER RAY: No, hell no.

CHAIRMAN SHACK: Right, so it --

MR. TREGONING: But nothing would change.

CHAIRMAN SHACK: But nothing would change.

MR. TREGONING: You still have 72 hours.

CHAIRMAN SHACK: You still have --

MEMBER CORRADINI: He answered the question. I think he answered the question with the double-ended guillotine. Ask the question again.

CHAIRMAN SHACK: He's ask of the TBS.

MEMBER RAY: Oh, yes, of course.

CHAIRMAN SHACK: For the single, yes.

MEMBER RAY: Yes, it has high pressure and low pressure safety injection concepts, absolutely.

MEMBER STETKAR: A lot of plants, I mean, even realistic analyses with PRAs, until you get to the --

CHAIRMAN SHACK: No, no, design basis analyses.

MEMBER RAY: Which could be the --

CHAIRMAN SHACK: The design basis, well, 95/95, it's different than --

MEMBER STETKAR: You can get well up into the break sizes, before you actually need the accumulators.

MEMBER RAY: Oh, yes.

MEMBER STETKAR: The accumulators help, but before you actually need them.

MEMBER RAY: Right, I misunderstood.

MEMBER ARMIJO: Did we miss this issue, in our previous reviews, the indirect failures?

MEMBER CORRADINI: It's been so long ago, I have no remembering.

MEMBER ARMIJO: I don't remember it being

discussed.

MEMBER STETKAR: Don't look at me, I have complete ignorance, because I wasn't around.

MEMBER ARMIJO: Well, I was around, but I remember the --

MEMBER RAY: I wasn't either, but I'm telling you, it's the one thing that's always been in my mind, on this discussion is not the pipe. My God, that's not what you're worried about.

MR. TREGONING: There's been no changes here, with respect to this, but you know, we haven't had a substantive discussion on the Reg Guide.

Again, these are mainly the conclusions of 1903. So, and we have had discussions on 1903, but that's not what we're talking about. We're not talking about issues with the 1903 analysis. We're talking about --

CHAIRMAN SHACK: Well, 1903 looks more favorable towards indirect failures, than the EPRI study.

MR. TREGONING: Well, again, because I think primarily, because they use the old hazard, the older hazard that you had mentioned.

CHAIRMAN SHACK: Right, but you know, then we still -- we make the statement that this is highly

plant specific and yet, --

MEMBER RAY: We don't do it.

CHAIRMAN SHACK: -- it goes off. I mean, the argument in the statement of considerations say, because of the relative capacities expected of seismic event, of sufficient magnitude to cause consequential failure within the primary system, would also induce failure of components in multiple trains of mitigation systems, or even induce multiple RCS pipe breaks.

Consequently, the risk contribution from seismically induced indirect failures is expected to depend more heavily on the relevant fragilities of plant components and systems, than the size of the TBS.

Therefore, the NRC believes that adjustments to the TBS for seismically induced indirect LOCAs is also not warranted, and you know, that's the argument that's presented in the statement of considerations, for what it's worth.

MEMBER STETKAR: I mean, the same could be said for the things that failed the piping, probably even more so. So, it's not that --

CHAIRMAN SHACK: I mean, that's --

MEMBER STETKAR: -- that I need to look at the piping or not the structures.

CHAIRMAN SHACK: I mean, that's the contrast, really, is the difference between the scrutiny that we give to the piping, and the pass, that we seem to give to the indirect failures.

MR. TREGONING: Would you like to discuss further?

CHAIRMAN SHACK: Yes, I think we've just about hit the end of this one.

MEMBER CORRADINI: Yes, it's going to come up again.

MR. TREGONING: I'll try to accelerate, at this point, and see if we can get back on schedule.

So, we've already talked a lot about the Reg Guide, so, maybe I can go through this pretty quickly.

The Reg Guide was based, at least the initial development, on Commission direction, which was also consistent with ACRS recommendations that we should develop regulatory guidance to provide methods for establishing if TBS was applicable to individual plants.

And even though we only got explicit direction on 1829, we interpreted that that guidance also extends to the seismic evaluation, as well.

So, when we looked at the regulatory

guide, we considered issues and implications with generic aspects of both NUREGs, the assumptions, the approach, the analyses, and we wanted to make sure that those generic aspects were applicable and maintained to individual plants.

So, that was really something going into the Reg Guide development, that we wanted to ensure that we met.

So, we determined -- we looked at several areas that may be affected by plant specific factors, not 1829 applicability. We looked at safety culture, current or continued operation, this would be operation with -- as the plant is currently configured, and then changes in plant operation that might affect LOCA frequencies, and then for 1903 applicability, as we're already discussed, we looked at risks associated with direct and indirect piping failures.

And the things that are covered in the Reg Guide, as we've already touched on, are current operation, changes in plant operation and then, the direct piping failure risk. So, that's what I'll talk a little bit about, as we go forward.

So, the philosophy and framework behind the regulatory guide is, an applicant would be

required only to address breaks larger than the proposed TBS, and these would be in the primary piping and then pressure boundary structural components, and the reason for this is, breaks below the TBS are still covered by the original design basis, so, there's no rule changes amenable to those breaks. So, that's why there's only a requirement to look at large break sizes.

What we tried to do as much as we could was to use information submitted that was relevant, under other programs, where possible, to provide justification of applicability.

So, we looked a processes that we had. We looked at the power upgrade process, the license renewal process and the leak before break submittals, and looked at what information was required for those, in these areas, and to see how much synergism we could get out of the information that would already be supplied as part of these analyses.

So, the part of the Reg Guide which looks at addressing NUREG 1829 applicability is intended to be largely a qualitative analysis, and what the applicant is required to do is to consider plant specific effect of variables that affect LOCA frequencies, and what are those things?

Well, they are the materials. They're the load. They're the environment. They are the mitigation plans and inspection procedures that they have in place for these systems, and they have to demonstrate both the adequacy of their current plant conditions and the insignificance of any proposed plant changes.

So, they have to ensure that any plant changes that they make, won't affect those variables, which affect LOCAs.

With respect to the guidance for addressing 1903 applicability, that's a multi-pronged, multi-option guidance. We try to provide options as much as we can, to maximize the applicability of that 1903 analysis, because even the direct piping failure analysis is not a trivial analysis.

So, we wanted to make sure that we had guidance and plans in place, that they could use the results of those analysis, if it were applicable, and they could demonstrate that.

If they can't, then we are -- there is also guidance in the Reg Guide for how you would actually conduct an analysis similar to what was done in 1903, at least for direct piping failures.

CHAIRMAN SHACK: I mean, I guess if I was

allocating after -- you know, the chances of finding a crack that big, in PWR piping, you know, indirect failures just seem so much more likely.

MR. TREGONING: Well, again, the nominal argument is that the flaws will be that big, but you also have to consider -- I mean, cast austenitic submitted components might actually fall below those limits, and they have, of course, a high degree of uncertainty, in terms of inspection challenges.

So, that's something that we want to ensure. We're also a bit concerned about continued embrittlement or maybe even thermal embrittlement of certain welds, sub-arch and shield metal arc welds.

So, there are aging considerations that we want to make sure are maintained, and if the demonstration shows that when you've accounted for these aging considerations, that you still need these large flaws to lead to failure, then you know, yes, they're certainly not a concern at that point, with the piping fragilities, under a seismic event.

But we are concerned that some situations you may reach, where you're down to maybe, you know, a 10 percent through-thickness flaw or maybe even less than that, then you start getting into more inspection challenges, and those are the types of situations that

we want to avoid, if possible.

So, the way the Reg Guide is laid out, if they demonstrate that they're over and above this 30 percent through flaw, they don't have to do anything further. As they get less than that, they have to meet higher criteria and demonstrate that they have plans in place to assure that they can find those flaws.

So, if they can't demonstrate the 30 percent flaw, then they have to compare the flaw that they have in a best estimate analysis with an ASME type flaw, that they would use during a -- that they would find and have to judge acceptability on, based on a standard ASME analysis, which looks at much lower loadings, but has more conservative assumptions in the analysis, and what you're doing there is comparing flaw sizes, and if the ASME flaw comes out being smaller, that's a flaw that they have to show they can inspect to, anyway.

If they fall below that ASME, then they would have to demonstrate as per the Reg Guide, that they have inspection capabilities in place that can reliably and accurately detect flaws that large, and then that, in and of itself, that starts to -- so, the hurdles start to become higher, as the smaller that

flaw gets, because demonstrating reliability and accuracy of your ISI methods has always been a challenge, because you have to deal with probability of detection arguments.

So, as the flaws get lower, the bar gets higher.

MEMBER STETKAR: That might be the deal breaker for, you know, adoption of 50.46a.

MR. TREGONING: Sure.

MEMBER STETKAR: For an applicant. It's voluntary.

MR. TREGONING: It's voluntary, that's correct. So, getting back now to general applicability, basically, what a plant has to do is demonstrate that they are consistent with their license basis, and I'd like to use the word `following best industry practice', in terms of mitigating degradation.

So, the first criteria, of course, that they have to demonstrate for PWSCC, that their aging management program is acceptable, and it's following all the NRC approved requirements.

Next, they have to look at their aging management programs and plans, and here, we've got different options.

I mean, if they are a plant that's come in and been approved for license renewal, obviously, we've given some -- we've already reviewed and looked at and approved those plans. So, we want to give them some benefit, for that approval.

So, really, all that's required is that they have to look at those AMP's and see if there are any deviations, but -- in how they're currently implementing those AMP's and what was enforced, or what was approved, sorry.

MEMBER ARMIJO: Do you provide any credit for the BWR guys that are using hydrogen water chemistry and noble metal chemical editions, as mitigation for IGSCC?

MR. TREGONING: Sure, I mean, that's part of --

MEMBER ARMIJO: Is that part of the base case, that it's --

MR. TREGONING: That would be part of the base case. I mean, that's expected.

MEMBER ARMIJO: Okay.

MR. TREGONING: When we developed LOCA frequencies for BWRs, those were the expected conditions that we --

MEMBER ARMIJO: Okay.

MR. TREGONING: -- that we considered. So, yes, that, in my mind, I mean, you know, there is mitigation that's required for IGSCC. The plants essentially have to come in, in BWR, and demonstrate that they're following best practices.

Now, they don't all have to use the same mitigation methods.

MEMBER ARMIJO: No, I understand that.

MR. TREGONING: Because we allow a variety of methods to be used.

So, certainly, there is, not only is there credit, but there is an expectation --

MEMBER ARMIJO: Okay.

MR. TREGONING: -- that they would demonstrate applicability with.

MEMBER STETKAR: Kind of a leading question, because we're going to be looking at changes to the GALL report, in -- I don't remember what the schedule -- October or November, but we haven't seen them yet, and we haven't seen the -- you know, we've looked at the draft Reg Guide enough to say that we're not going to formally review it until the public comments come back.

So, for all practical purposes, we don't know what's in the Reg Guide and we don't know what's

in the GALL report.

Is there anything that you know of, in the changes to the GALL report, that would affect anything in the Reg Guide, or is it general enough that it doesn't affect anything?

MR. TREGONING: You know, I think it's -- it's general enough that there's nothing obvious, a priority that jumps out --

MEMBER STETKAR: Especially on corrosion and stuff like that, you know, the piping system and stuff like that.

MR. TREGONING: Yes, I mean, the thing that you always struggle with, with license renewal, and I don't want to get into a license renewal discussion --

MEMBER STETKAR: I'm just curious, since you referenced the GALL report, and I know that Rev 2 or whatever it is that's coming up, that -- did you have that benefit of that information when you wrote the Reg Guide?

MR. TREGONING: You know, we certainly knew some of the things that were being updated, in the GALL report.

I think, you know, the main thing that's continuing to be a challenge is -- I don't know that -- I don't think it has a huge effect, with respect to

the Reg Guide, but I know in -- with respect to the GALL update, is evaluation of environmentally assisted fatigue.

That's an area that, you know, in terms of assessing degradation, that you know, we have some plants that haven't had to consider it at all, and we have other plants that have to consider it significantly, and there is just very inconsistent, based on when plants have come in for their approval, what guidance we had in place, and that's the challenge, when you get into license renewal, and trying to assess these issues, is the fact that, you know, the guidance has been evolving and every plant has -- it's very specific, in terms of what their basis is that they've been approved for, for license renewal.

MEMBER STETKAR: Does the Reg Guide refer specifically to the GALL report and Rev 1, or Rev 2 -- I guess, we're on Rev 1 now, right?

MR. TREGONING: Yes.

MEMBER STETKAR: I don't remember, whatever it is, does it refer to a specific revision of the GALL report?

MR. TREGONING: It does not.

MEMBER STETKAR: Okay, just refers to the

NUREG, in general.

MR. TREGONING: Yes, just in general, that these are best practices and the assumption would be that they're following those.

And then if they haven't gotten approval, but they've applied, the same philosophy would apply, that they'd have to look at any deviations from what our acceptance criteria is and the standard review plan.

Now, if they haven't been approved at all, or if they haven't applied at all for license renewal, they would perform an alternative evaluation, which would essentially require them to outline and document and assess their aging management programs, and how well they would mitigate degradation of aging mechanism, and again, the focus there, those mechanisms that are outlined in the GALL report, I mean, mechanisms that are certainly well known, and they would be ones that would be applicable, only to the primary loop piping or the primary boundary structural components.

With respect to the plant specific attributes that would have to be considered, again, we tried to model the Reg Guide quite a bit over the analysis that's done for LBB submittals, and really,

what they're doing there is they're looking and trying to evaluate any plant specific effects, related to variables that would affect LOCAs.

So, and primarily, these are things like materials, loading conditions and environments, and geometries and configurations.

So, really, this part of the analysis would just have them look at their plant and make sure there's nothing unique that would cause them to stand out from other plants, that might invalidate these generic LOCA frequencies.

The new piece, something we've never done, at least in my mind, for evaluations like these in the past, is, they have to look at the effects of plant changes and ensure that the original technical basis is not invalidated by those changes.

Again, I don't think -- I'm not aware of any other case where we've required them to make sure that those basis as applicable, as they continue to make changes under the rule.

A lot of this aspect of these analyses are modeled after the power upgrade review standard, as well as the LBB SRP. So, again, we've used guidance there.

There is two steps in the analysis

process. Again, these are for non-seismic. They look at the effects of direct primary loop piping failures and they evaluate the effects on -- of indirect primary loop piping failures.

So, and there is various options that they can use, to do these analysis, some, more complicated than the others, depending on what prior analyses in these areas that they may have.

If there are prior analyses, for instance, for indirect failures, that are still sufficient and are not affected by the plant changes, we would consider it acceptable, just to justify or to demonstrate why they remain acceptable or sufficient, and they wouldn't have to do a new analysis.

But if they're not able to make that case, then they would have to address the impact of the changes on, you know, things like dynamic effects and then, missile protection for the pipes. So, classic indirect failure modes, and then at the end of the day, make an argument or a determination, if those changes would result in increases in the LOCA frequencies.

We've talked a lot about this, and I think your views have been made very clear. So, I just want to briefly step through what we're requiring for

direct piping failures.

So, again, this requires a plant specific analysis of hypothetically flawed components, in the primary loop. Again, there is options to try to maximize the use and applicability of the 1903 analysis and results, and here, I use the word that I cautioned you against using, demonstrate that that analysis is bounding, but really, more accurately, within the range of results of 1903, and if they can't do that, we still -- there are still options that they can use, aspects of that analysis, within a plant specific evaluation.

And then there is very specific analysis steps that model the analysis that was done in 1903, if a plant -- if an applicant actually had to run through the analysis for their plant, if they couldn't demonstrate that the 1903 results were in and of themselves, directly applicable.

So, where are we at with the regulatory guide itself? We came to you in March, prior to public comment, and you did agree to waive review until after the public comment period.

We published 1216 for public comment on June 28th. We were configured within the public comment period for about two weeks, when the industry

asked if they could extend the public comment period, which we agreed to do. That's been extended until November 25th.

We're actually having a public meeting on the draft guide. I can take the tentative off now. It will be a public meeting on the 30th. The purpose of that meeting is to clarify any positions or any guidance that's included in the draft guide, to try to inform, better inform the public comment period, plus, address any questions that the stakeholders might have, at that time.

So, the key milestones, at least at this point, within 2011, we're hoping to address the public comments within about a couple of month time frame, and we're hoping to finalize DG-1216, based on public comment, some time in January, at least in an interim.

We would be proposing to come to the ACRS in February or March time frame, after we've addressed the public comments, and then, the plan would be, at least the current plan, would be to publish that guidance six months, within six months after the final rule, as given to the Commission, and the idea would be to publish the regulatory guide, commensurate with the publication of the rule itself.

Now, the other thing we're looking at

doing here is initiating, and something we'll be discussing in the pilot, in the public meeting, as well, is initiating a pilot study to actually evaluate the Reg Guide through several, at least one or maybe more, pilot plant applications.

So, that's something that we'll also be talking about at this September 30th meeting, and the hope would be, if we get some plants to volunteer, that we would initiate that pilot study some time around January, and that when we come to brief the ACRS, we would not only discuss the public comments, but then also, our plans related to the pilot study.

So, long term milestones, estimating one to two years to complete the pilot study and that the Reg Guide would be revised within a relatively short time after completing the pilot study, and then published accordingly.

So, that's it, with respect to the regulatory guide, and then I briefly wanted to touch on then, comments we got back on the rule, both related to transition break size and then, the applicability guidance.

So, with respect to the transition break size, just a little bit more overview, just to remind you what that is, for the BWRs, the TBS has been set

a cross-sectional flow area of the larger of either the feed-water or the RHR piping that's inside primary containment.

And for PWRs, it's the cross-sectional flow area, the largest piping attached to the RCS main loop. So, that's what the TBS is now, in the proposed final rule.

Comments we got back, we got comments -- we got one set of comments related to the PWRs, and the BWRs. Of course, they've largely said the same thing, that in their opinion, the TBS was conservative, overly conservative and in fact, those were words that were used for the BWR case, and that there was a recommendation that an absolute size be set for 16-inch schedule 80 pipe.

MEMBER ARMIJO: Were there any particular pipe that they were -- was that the RHR, is it about a 16-incher?

MR. TREGONING: Yes, that was --

MEMBER ARMIJO: But not the feed-water, so they were kind of --

MR. TREGONING: Not the feed-water, so, but again, they recommended this pipe diameter, but they didn't provide any supporting rationale or basis, as to why that pipe size and schedule is appropriate as

the TBS.

So, you know, there was nothing really for us to evaluate.

MEMBER ARMIJO: So, they challenged the results of the expert elicitation, as being --

MR. TREGONING: No, they didn't challenge the results of the expert elicitation. They challenged the TBS selection, as being too conservative, and being not --

MEMBER ARMIJO: Well, that's --

MR. TREGONING: If anything, they would question that the TBS is too conservative to be a 10 to the minus 5th per year event. They didn't explicitly say that, but that was implicitly, what they were challenging, by saying it's too conservative.

MEMBER ARMIJO: But they didn't provide a document or any analysis --

MR. TREGONING: No, there was no -- they just provided why a 16-inch schedule 80 pipe would be a more acceptable transition break size.

MEMBER ARMIJO: Well, that's probably because it's of the same size of your --

MR. TREGONING: Yes, then I would give more benefit --

MEMBER ARMIJO: Well, it's about the same size, the largest PWR pipe, right? That's probably not the best logic.

MR. TREGONING: But smaller than the current TBS. For PWR -- and again, this was a comment that we'd actually received, when we went out for the prior rule, as well. So, this wasn't any new comment.

Same with PWRs, this was a comment that we heard in the past, and the recommendation there was, to have separate transition break sizes, one for the hot-leg and one for the cold-leg, and it would effectively be the largest attached pipe, for either of those systems.

Again, while that was the recommendation, again, there was no basis document or any real basis rationale that was provided to support that recommendation, and when we did the elicitation, this was something when we were determining the TBS, we actually -- staff actually debated this quite a bit.

And the bottom line is that we couldn't find, even though qualitatively, one would expect a difference in the break frequencies, as a function of temperature for many of these mechanisms, especially SCC type of mechanisms, there really wasn't enough of a quantitative or a qualitative basis, within the

elicitation, to support that rationale, and recognizing that we're not dealing with just frequency contributions, due to a complete pipe failure, but also, partial pipe breaks, as well, of these bigger pipe systems.

That was one of the -- that was really, a primary driving force behind considering just one TBS, and not separate break sizes, depending on if you were trying to analyze hot-leg or cold-leg breaks.

So, as a result of either of those comments, we really made no change to the TBS, nor any changes to the rules, for either the B's or P's.

MEMBER ARMIJO: On the BWR public comment, was that from the owners group or --

MR. TREGONING: Yes, that was BWRs owners group, I believe.

MEMBER ARMIJO: Yes, not GE or --

MR. TREGONING: No, I know it wasn't GE. I believe it was BWR owners group. PWR comment, I think we got that comment from several people. It was, you know, it was one of those, almost like a spam comment. We got it from NEI and then we also got it from a few individual licensees. It was clear that there had been some collaboration on their public comments, and that was based on the language.

Clearly, there was clearly, some plagiarism at work.

MEMBER ARMIJO: Collaboration.

MR. TREGONING: Collaboration, let's call it collaboration. If I were a professor, you know, I would maybe say plagiarism, but --

Okay, now, I want to discuss plant specific -- or comments that we got, related to the applicability guidance -- the applicability requirements within the rule.

There were two comments that were provided. The first comment said that plant specific assessments of the effective seismically-induced break should not required at all.

So, maybe in line with your argument, if you're not requiring them for indirect, why are we doing them for direct? That's what this commenter, I think, would probably agree with, that rationale, and they cited the EPRI studies that demonstrated the negative contribution of indirect seismically-induced risk, and again, we got a similar comment here, on the initial proposed rule.

MEMBER STETKAR: Just being a risk assessment guy, I hate the use of the word `risk' as a surrogate for pipe break frequency.

MR. TREGONING: Right, they specifically

said LOCA risk.

MEMBER STETKAR: LOCA risk, all right.

MR. TREGONING: I'm not paraphrasing. That was the language --

MEMBER STETKAR: Okay, I understand that.

MR. TREGONING: I understand your --

MEMBER STETKAR: That statement might actually be true.

MR. TREGONING: Right, right.

CHAIRMAN SHACK: So, that's actually NEI's argument

MEMBER STETKAR: I understand that.

CHAIRMAN SHACK: The change in risk should be the primary method.

MEMBER STETKAR: Yes, I understand that.

MR. TREGONING: Right. Now, our response, and we've had a lot of discussion about the response here, so, or at least, related aspects.

We disagree that plant specific assessment should not be required and then, again, these are all bullets that are based on the new -- the 1903 analysis, and really, it's this last bullet that -- that we want to make sure would be verified with any plant specific analysis, because again, we didn't look at all the plants and we recognize that based on the

information that we had in the 1903 analysis, we didn't have the latest information, especially with respect to seismicity, and the continued modification of the seismic hazard estimates.

So, we want to make sure in this analysis, that that plant information hasn't changed, either. So, that's another reason for that, and again, like I said before, we want to make sure that those plant specific results falls within the bounds, or the range of that 1903 analysis, and again, at least this part is consistent with what ACRS comments have been made in the past, as well as Commission direction.

So, this slide, I'm sure we've discussed this a lot already. We actually agreed with the commenter, that -- in fact, the Reg Guide itself does not require assessment of indirect LOCAs, and we've talked about that quite a bit already, understand the disagreement right now, that ACRS has expressed in this position.

MEMBER STETKAR: ACRS hasn't expressed it, yet.

MR. TREGONING: Well, this Subcommittee has expressed it.

MEMBER ARMIJO: Subcommittee.

MR. TREGONING: Sorry, I don't mean to

postulate, at this point.

MEMBER STETKAR: Yes, please. Individuals have been overruled in the past, at the Committee level.

MR. TREGONING: We've heard the concerns expressed today. But again, our basis was, events typically causing these potential failures, especially due to these larger earthquakes. The expectation, based on comparison of fragilities, as well as operating experiences are also going to fail the other ECCS mitigation systems, as well.

So, with these large earthquakes, if you fail the piping and/or the support, you're probably going to be failing lots of other systems, as well.

MEMBER RAY: Disagree.

MR. TREGONING: And yes.

MEMBER STETKAR: Don't look at me. I don't know.

MEMBER RAY: I just disagree with the use of the word `probably', which implies more than, I think, is justified.

MR. TREGONING: Well, again, that's based on information that we've seen, and again, not just in risk studies, but operating experience, when they've done walk-down for plants, in terms of determining

what's failed under these relatively large earthquakes.

If they wanted to make -- I guess, the one thing we didn't talk about, if a licensee wanted to make changes that would affect something related to their seismic design basis, they would have to justify those proposed changes, using a plant specific analysis, all right.

MEMBER STETKAR: That's right.

MR. TREGONING: So, in that case, they would have to do an analysis.

MEMBER STETKAR: If they want to make changes.

MR. TREGONING: If they want to make changes.

MEMBER STETKAR: If they never --

MR. TREGONING: Changes, that would affect their seismic design basis.

MEMBER STETKAR: Yes, that's right, and that's clear, in there, that's right.

MR. TREGONING: Right.

MEMBER STETKAR: But if they don't want to make any changes that affect the seismic design basis --

MR. TREGONING: Then that's correct, a

correct understanding.

MEMBER STETKAR: Off the table.

MR. TREGONING: That's correct, understanding, that's currently how the Reg Guide is structured, that's correct.

MEMBER STETKAR: As is the statement of considerations for the rule and the rule, itself.

MR. TREGONING: As a result of this comment, again, we made not changes to the rule, itself.

The second comment, the expectation for the re-evaluation of the applicability of the TBS after plant changes embeds the continuous process in the rule. That was a comment.

The implementation costs and associated reporting requirements have the potential to limit industry-wide implementation of 50.46a. That was another part of this comment, and then also, this commenter believes that a simplified method to ensure the applicability needs, needs to be developed.

And then finally, in line with this first comment, recommending that some limitation on continuously assuring applicability needs to be developed, as well.

So, basically, the concern is, this

continual loop, that every time you have to make a plant change, you have to demonstrate that your TBS isn't affected.

Okay, we largely agreed with the commenter here. We certainly recognize the need to develop simplified guidance. You may argue how simplified the Reg Guide process -- Reg Guide is, or not. I think it's a -- while it tries to build on past submittals, I think for plants that are up to date and have come in for license approval and can demonstrate that their plant is within the bounds of the 1903 analysis, I think it is a relatively simplified analysis, that needs to be done.

But plants that don't meet those criteria, I think it's a fairly complex analysis that would need to be done. So, I think it really will depend on the plant and the status of that plant.

But at least, there is guidance that we've proposed out there, for demonstrating applicability.

We also agree that the demonstration costs may prevent wide implementation of 50.46a. We've discussed this before, it's a voluntary rule. There is also hope that by putting out this Reg Guide, that it will allow plants to more accurately assess what their implementation costs would be, because they have

guidance conceptually, that they could follow and they can make a better assessment of what those costs are.

Also, one of the reasons, or at least part of the reasons for doing this pilot study, to evaluate guidance, first of all, we want to evaluate technically, how acceptable the Reg Guide is and if there is any other holes that we may be missing in it, but also, we think through the pilot study, it will provide a basis for potential applicants to get a better handle on what their implementation costs are, associated with coming into the rule.

And demonstrating applicability is just one of the implementation costs associated. Whether it's the biggest implementation cost or not, I don't know, at this point. It's certainly not in -- it's potentially, not an insignificant cost. So, that's why this pilot plant study is being considered, to try to get an assessment of what those costs may be.

MEMBER STETKAR: Rob, this says `will solicit interest'. Do you have any informal communications from anyone who has expressed any interest?

MR. TREGONING: Yes.

MEMBER STETKAR: Don't name anybody, but there is --

MR. TREGONING: No plant has come forward and said, "We would like to be part of this study." So, we haven't had that level of commitment.

MEMBER STETKAR: Okay, okay.

MR. TREGONING: The only thing I can say is, there's been general discussions with the industry, and they're generally in agreement that a pilot plant study would be a good idea, but no one has agreed to be part of that study.

MEMBER STETKAR: Okay, okay.

MR. TREGONING: I think the expectation would be, if the pilot -- if we don't get interest in a pilot plant study, that would -- to me, that would infer that there is not interest in this rule.

MEMBER STETKAR: That's why I asked, yes.

MR. TREGONING: So, and my expectation would be, plants that step forward for a pilot plant, probably are very interested in applying for the rule.

So, it will be -- hopefully, in the September meeting, we'll get more information on that.

MEMBER STETKAR: Okay.

MR. TREGONING: Or if we don't, and I don't expect a firm commitment resulting from that meeting.

MEMBER STETKAR: It's just general, I was just curious about general interest, with some level

of specificity, rather than --

MR. TREGONING: There's general interest right now, with no level of specificity.

MEMBER STETKAR: Yes, that's what I --

MR. TREGONING: I think it would be safe to say, but I hope as a result from the September meeting, that we at least develop a time frame and a frame work for getting more specific commitments, and when those might occur, if they occur.

And then the aspect of the comment that talks about the continual process, I mean, yes, it's a continual change process, and that's something that's -- would be a new addition, but we believe that it's an important addition, to make sure that the initial evaluation that's done is not invalidated by plant changes.

In reality, I think many of the plant changes that we're talking about will be no, never mind. If they want to take an accumulator out of service, that has no effect on LOCA frequencies.

But if they want to do a power upgrade, that potentially has an effect on LOCA frequencies, and those are the things that we want to make sure that we cover, because this is a broad, enabling rule.

So, many of the system mitigation types of

changes, this is a "No, never mind." There's more fundamental changes that we want to make sure, are captured and not invalidated.

MEMBER STETKAR: Or upgrades or changes to aging management programs for structural supports, or that type of thing.

MR. TREGONING: That would be the type of thing you're trying to capture, and that's all I had. We've got time for more discussion, if we want to go back and talk indirect failures some more.

Any other questions that any of the Committee members have?

(No response.)

MR. TREGONING: And again, you're certainly going to hear more about this Reg Guide, because we'll be looking to schedule something, and again, the expectation I would have is, we would have a meeting just on the regulatory guide, at the Subcommittee level, where we more fully discuss, of course, depending on what you want to hear, we'd more fully discuss the contents, the technical contents of that regulatory guide, and then we would certainly go into public comments that we received, as well as any plans that have been developed, or at least discussed, with respect to a pilot plant study, at that time.

So, when the time comes, we'll be amenable to coming in and for as long as, I'm assuming it would be the Subcommittee, as well, and we will discuss, as long as you would like, this Reg Guide and delve into as much depth as you would like to, because we've had a lot of discussion about the technical basis documents. We've only had, I would say, cursory discussions about the Reg Guide, up to this point. That's all I had.

CHAIRMAN SHACK: Okay, we're back on schedule. Time to break for lunch, and we will return at one o'clock.

(Whereupon the above-entitled matter went off the record at approximately 12:00 p.m. and resumed at approximately 1:05 p.m.)

CHAIRMAN SHACK: We'll come back into session. Tim, I guess it's up to you now, with thermal-hydraulic analyses.

MR. COLLINS: All right, I will discuss the comments that we received on -- that are related to thermal-hydraulic analysis.

We received basically, six comments in this area, and I'll go through each one of them.

First comment I want to discuss, a commenter noted that the rule was changed since the

previous version, to require NRC review and approval of the analysis methods that are used for the breaks larger than the TBS. The previous rule did not require prior staff review and approval, and the commenter recommended that the models ought to be available for inspection, but that NRC review and approval for beyond design basis events should not be required.

And the commenter believes that would be more consistent with the classification of the events as being beyond design basis, and that NRC resources could be lightened, they need to be lightened for NRC resources, if prior approval was not required.

MEMBER ABDEL-KHALIK: That was probably not the main motivation for this comment, though, but it was the comment.

MR. COLLINS: It was the comment, and the commenter also recommended, however, that the licensees or vendor should have the option of requesting NRC approval, even though it wouldn't be required.

(Off the record comments.)

Our response to this comment, we didn't make any change to the rule, in response to this comment. We had received a comment from the ACRS, a

couple of years, back in, I think it was November 2006, I think, in your letter, which recommended that we do prior review and approval and that it would provide more confidence in the analysis results for the breaks larger than the TBS, and we also considered the resource question that the commenter had raised, and we noted that the models that are currently used, would take almost no modification to use for 50.46a, the removal of the single failure requirement, the removal of the off-site power, or allowing off-site power, simple inputs to the existing codes.

So, unless somebody was going to make changes to the analysis models, which were relatively different than that, which would probably introduce more uncertainty in the analysis, we thought it was worth while to spend the resources to see just what was being introduced by those changes. So, we didn't make any change to the rule.

The next comment, the commenter noted that the supplement rule requires that evaluation models larger than the TBS must utilize comparisons to applicable experimental data.

This is the same comment we received on an earlier version of the rule. The commenter indicated that other approaches, such as comparison of results

to other codes or to textbook results should provide sufficient justification, and then he noted that there's a sufficient justification clause in the rule, and he pointed to that, saying that since it's a low risk, that should be sufficient justification for these types of events.

Again, we didn't make a change to the rule. We noted that the large break LOCA models were largely developed using empirical correlations, and we recognized, you know, the lower risk significance, but -- and we think that the extent and the rigor of the comparisons to data may vary with model importance. We still think that you need to validate that data, using experiments.

And this comment, the commenter noted that the rule requires the capability to provide on-site power, via manual actions, if non-safety equipment is credited, and the commenter noted that he thought this was contrary to the notion that beyond design basis LOCAs could be analyzed without assuming a loss of off-site power.

And the commenter also noted that it placed additional burden on the licensee, if the non-safety equipment had to be credited, and would likely require additional analysis.

Again, we didn't make any change to the rule. We think that the commenter may have misunderstood the requirement. His credit is allowed in the analysis for off-site power, all right.

You don't have to include the timing of the manual actions, to add on-site power, in your actual mitigation analysis.

Therefore, there wouldn't be any impact on operational set points, or any parameters. It's really a severe accident mitigation feature, defense-in-depth is your accident mitigation, and we didn't see that a burden was very likely to be impose on any licensee, unless they made a very significant change to either their core design or their ECCS configuration, and in the event that they did that, we thought it was worth while for them to take the additional step to provide off-site power, as a defense-in-depth measure, or on-site, provide on-site power. So, we left this in the rule.

The fourth comment, we had put a question out in the supplementary rule, and we asked whether or not we should even leave this coolable geometry in the rule, which would allow licensees to specify their own metrics for coolable geometry, of should we just say, "No, you always have to use a pre-specified metric,

such as peak temperature or oxidation, like is used today," and the reason we put this question out was because we're having such hard time trying to get the current 50.46b criteria settled, that it just doesn't make sense to now, try and do a further refinement of the criteria for breaks larger than the TBS?

We received comments on both sides of the fence on this one. The industry comments basically said, "Well, it will still allow some greater flexibility for compliance and it could potentially reduce the scope and cost," and they said it would increase the likelihood that licensees may find implementation benefits.

The opposing comments stated that the existing criteria themselves are not conservative, and even the models are not conservative. Well, that goes for the comments, now, and how we handled these.

Most of our evaluation of these comments had to do with the one that opposed keeping a coolable geometry.

We were in agreement, basically, with the industry, it might provide them some flexibility and, you know, if they want to try to use it, that's fine.

But for the basis for the comments that opposed retaining the criteria, they raised questions

about the adequacy of the current acceptance criteria and the current evaluation models.

Okay, these same concerns were submitted to this staff in a petition for rule making and are being handled under that process. But we also noted that coolable geometry is, really, it's a high level criteria, almost performance based type of criteria, and you still need more specific metrics to demonstrate that you satisfy that coolable geometry criteria.

So, even if the petition for rule making, if that evaluation should conclude that the current criteria are not conservative and it should conclude that the current evaluation models are not conservative, we would to fix the rules -- to fix the models and the existing criteria, but it wouldn't preclude the use of the coolable geometry criteria, okay.

CHAIRMAN SHACK: I did have one -- why not just simply refer to 50.46b, rather than build in the 2,217 percent into this portion of the rule, since you may well end up changing 50.46b?

MR. COLLINS: Did you submit comment six? I think that's exactly what the comment said.

MEMBER CORRADINI: That's exactly what I

just whispered to him, I said, "That sounded like your comment."

MR. COLLINS: The exact comment was submitted to us.

CHAIRMAN SHACK: Okay.

MR. COLLINS: I think it's comment five.

CHAIRMAN SHACK: It's coming?

MR. COLLINS: Here we go, comment five, yes.

MEMBER CORRADINI: So, that's yours?

MR. COLLINS: Well, it's exactly the same as the comment just made.

A commenter said, "You know, why don't we just reference 50.46b, for breaks larger than the TBS -- or for breaks less than the TBS," rather than carry this stuff over into the new regulation, and that it would be administratively cleaner, and that it would be a lot easier if we subsequently changed the 50.46b criteria, and we won't have to change 50.46a, okay.

And our response to that was, "Well, it's certainly feasible," but we thought, you know, we also like all-inclusive rules, because we think they provide a clearer view of the totality of the requirements, and when you start referring, in part, one regulation inside of another regulation, you think

there is just as much of a chance that somebody is going to misinterpret what the totality of the requirements are. So, we figure we could have really gone either way, but we left it the way it was.

MEMBER CORRADINI: But you could have also done an `or'. You could have done, quoting this `or' go to -- it was just a comment.

MR. COLLINS:

MEMBER CORRADINI: But you could get an inconsistency, the way you've left it, though, is that a fair way of putting it?

If you change --

CHAIRMAN SHACK: It would summarize two rules.

MR. COLLINS: Yes, right, when we subsequently change it, we'll have to xerox the --

MEMBER CORRADINI: Okay.

MR. COLLINS: -- cut and paste, and put in the revised 50.46b into --

CHAIRMAN SHACK: I mean, if that was all it was, that would be easy. You know, but a rule change is still --

MEMBER RAY: A big deal.

MR. DUDLEY: Well, we'll do it when we revise 50.46b.

MR. COLLINS: Right, we're going to have to it --

CHAIRMAN SHACK: There should be a conforming change submitted with that.

MR. COLLINS: We could have done it either way. The last TH comments was that commenter said that the rule should not be promulgated until after the ECCS acceptance criteria in 50.46b are modified, to account for the new experimental data cladding ductility.

And noted again, that this is necessary because the current criteria are not conservative and the models are not conservative, and that if a licensee comes in with a change under 50.46a, it's likely to -- could involve a power upgrade, could be more challenging to the fuel.

This again, was a comment that was raised by ACRS, in their November 16th letter, in 2006. It was a -- actually, the letter comment -- mentioned, "We shouldn't do it," and at the same time explained an alternative that will allow us to do it, okay.

It went to the Commission, anyway, the issue went to the Commission, and the Commission determined that there was no need to hold up this rule making until 50.46b was completed, and the basis was

basically that all the data that's going to be used for the 50.46b rule making could be used in the review of a 50.46a submittal, to assure that there's enough safety margin in whatever gets approved by the staff. So, we didn't make a change to the rule again, based on the previous Commission guidance, and that's it, for the comments on thermal-hydraulic analysis.

MEMBER RAY: So, the issue of holding up 50.46a, in order to clear up the -- 50.46b has already been addressed by the Commission, and they say, "Don't hold it up."

MR. COLLINS: They said, "Don't hold it up." As a matter of fact, I think we recommended holding it up.

MEMBER ARMIJO: We did, yes.

MR. COLLINS: Yes.

MEMBER RAY: Kind of makes sense.

MR. COLLINS: In the Commission paper, in response to the comments of the November 6th letter, and we recommended that it -- we said it seemed to be more logical for us to hold this, put this in abeyance until 50.46b was done, and the Commission came back and said, "No."

MEMBER RAY: Okay.

MR. COLLINS: So, that was it.

MEMBER RAY: We don't have to worry about that.

MR. COLLINS: Any questions?

CHAIRMAN SHACK: Onto PRA, I guess.

MR. COLLINS: PRA?

CHAIRMAN SHACK: Yes, PRA.

MR. COLLINS: Great.

MR. DINSMORE: Hello, my name is Stephen Dinsmore. I'm a senior reliability and risk analyst in the PRA Licensing Branch in the Division of Risk Assessment, in NRR, and I'm going to talk to you mostly about the responses to the public comments relating to PRA. Since we talked a lot about this, this morning, it should go blazingly fast, if I can find my presentation.

MEMBER ARMIJO: Blazingly fast, I like that.

MR. DINSMORE: Let's see, this is just a quick comment overview. There were two major comments, well, major comments means, it was a comment that requested a substantive change in the rule.

There were two of them that did result in substantive changes, had to do with the 14 days and the LRF. There were two others that resulted in minor changes to the rules, and those had to do with minimal

and PRI update.

There were two comments that resulted in no change -- or these two major comments that resulted in no changes, which was the very small and accumulative, and then there was a bunch of minor -- well, several minor comments that either resulted in no changes or editorial changes.

Comment one, we talked about this, this morning. This is about the prescriptive restriction that you can't operate on a configuration, demonstrate -- not demonstrated to meet the acceptance criteria, for more than 14 days in any 12 month period.

The comments were that it's unnecessary because a per year limit is complex and contrary to how current tech spec's are defined. Traditionally conservative ECCS analyses means that the double-ended guillotine break LOCAs could still really be mitigated.

And then the final comment was, current risk-informed monitoring process, the maintenance rule and risk-informed tech spec's should be relied upon without unique control mechanisms. We'll go through those, kind of one at a time.

The per year limit is complex and contrary to how current tech spec's are defined. We agree that

it is complex. There are some tech spec's that have a cumulative limit. The most simpler ones are the ones that have a cumulative limit of radiation dose per year, at the boundary.

We found -- we saw another one that had another limit, but we couldn't re-find it. So, I'm not -- so, they're definitely unusual. They are -- they do exist, and we use them if we think they're necessary, and so, in this case, we kind of -- we thought it was necessary.

MEMBER ABDEL-KHALIK: And this limit would be, sort of like a running total, keeping track, since the last time that this was invoked, or what?

MR. DINSMORE: The limit would be --

MEMBER ABDEL-KHALIK: The annual limit?

MR. DINSMORE: Well, what they usually use in the tech spec's is calendar year.

MEMBER ABDEL-KHALIK: Calendar year?

MR. DINSMORE: And what we said is a 12 month period. So, I --

MEMBER STETKAR: This would be a running total, is what it would be?

MR. DINSMORE: Yes, a running total.

MEMBER ABDEL-KHALIK: Right.

MR. DINSMORE: Yes.

CHAIRMAN SHACK: Cumulative over a 12 year --

MEMBER STETKAR: Yes, but it continues?

MR. DINSMORE: Yes.

MEMBER STETKAR: It's not January 1st --

MR. DINSMORE: Right.

MEMBER STETKAR: -- through December 31st. It's in a running 12 month period.

MR. DINSMORE: Yes, that's the way --

MEMBER STETKAR: Which is appropriate, if you're thinking about, on availability.

MEMBER ABDEL-KHALIK: Right.

MR. DINSMORE: The next comment, traditionally conservative ECCS analysis means that the double-ended guillotine break LOCA could still be mitigated. We disagree because we need an acceptable TH analysis to demonstrate success.

And then this one, the current risk-informed monitoring process is, the maintenance rule and the risk-informed tech spec should be relied upon without unique control mechanism.

We disagreed with that, because the current processes deal with degraded mitigated functions, one LPSI train instead of two, but not with loss of functions.

The current tech spec's, usually, if you lose function, you get about an hour to shut down.

However, a couple of months ago -- we put -- we actually approved a WCAP related to tech spec initiative six, which does deal with loss of function. But this -- it's different then the current processes, in that they haven't really yet been implemented.

Some of the differences are, they usually start with a time, 24 hours or 72 hours, that they need, and then they'll do a risk calculation to demonstrate that getting that time is not subject to excessive risk.

So, they don't start with risk and find out how much time they get. They take the time they need and they find out how much risk it is.

Then the other one that might be more difficult for these guys, you can't voluntarily enter these things. These things, if you enter one involuntarily, you have the time, but you're not suppose to voluntarily enter them.

So, but the general idea was, "Well, okay, now, we've started down the path that we're going to learn how to deal with loss of functions in a risk-informed world," so, we went back and we changed the rule, and I'm actually glad we did, for a number of

reasons, and this isn't exact paraphrase, but it's pretty close.

For LOCAs larger than TBS, operation of plant operating configuration not demonstrated to meet the acceptance criteria may not exceed a short time. So, that's the requirement, a short time, and a short time is either a total of 14 days in any 12 month period, or an alternative proposed by the licensee and approved by the NRC.

Now, the SLC write-up you had kind of confused us a little bit, whether the alternative could be 10 days per year or 20 days per year, but it's meant to be 14 days per year or something else, and the new one will have that text fixed, and then there's other bookkeeping things we stuck in there.

They've got to submit a description of the risk-informed evaluation, if they want to do an alternative, and then we got acceptance criteria for that evaluation. Must be that any alternative that may be proposed is consistent with the mitigative capability available, configuration specific risks, philosophy of defense-and-depth and adequate safety margins, which we plucked those things out of the tech spec initiative six SE.

So, again, we started moving down the path

of dealing with this. We changed the rule, so that we could eventually deal with it.

Now, the 14 days, we didn't want to just say `a short time' and put a period there, because, again, we didn't know how to do that, and if you have an alternative in here that's clean and crisp --

MEMBER ABDEL-KHALIK: Seventy-two hours.

MR. DINSMORE: Well, we did come up --

MEMBER STETKAR: Seventy-two hours, I can calculate a number that --

MR. DINSMORE: Right.

MEMBER STETKAR: -- justifies 72 hours and then, let me go in and fight for something more.

MR. DINSMORE: You're right.

MEMBER STETKAR: Which the current rule let's me go in and fight for 30 days.

MR. DINSMORE: Right.

MEMBER ABDEL-KHALIK: Or be always happy whether it's 14 days or --

MEMBER STETKAR: Or 12 years, or whatever.

MEMBER RAY: Yes, I can say, if somebody lives under tech spec's, that 14 days is viewed as really, not very important. Seventy-two hours is the norm, for diesels.

MEMBER STETKAR: But all I'm saying is that

numerically, if I step back and if I presume that the frequency of these events is 10 to the minus five per year, which we're hearing from seismic, from all of that sort of stuff, and I take a four percent unavailability, which is 14 days in a 12 month period, and I do the multiplication, I get four times 10 to the minus seven core damage frequency.

MEMBER RAY: I'm taking --

MEMBER STETKAR: If I take 72 hours, I get one times 10 to the minus seven, which, according to the verbiage in here, is considered minimal.

MEMBER ABDEL-KHALIK: Right, right.

MEMBER STETKAR: You know, it's not 27 ½ hours, it's not two hours, it's not zero, and specifying -- you know, throwing something in there that specifies 72 hours, get people's attention, and you allow them to justify on a plant specific basis, something that would be longer, right, as this does.

MR. DINSMORE: Yes, we --

MEMBER STETKAR: Longer then 14 days.

MR. DINSMORE: Again, since we never really was -- we never really worried much about the 14 days, we hadn't thought of it. But actually, that's -- you would prefer that solution, than us to just kind of indicate in the SOC that, "Well, we know that 14 hours

is set at four times 10 to the minus seven," which is still acceptable.

MEMBER STETKAR: Your know, it's -- I'm not going to try to specify things, because I might even have a problem with the 10 to the minus seven, you know, for new reactors, which is a different issue.

But even for existing -- for operating plants, it's not clear. You have to be careful. I don't want to specify what I think might satisfy me, because I'm an individual. I'm not the Subcommittee. I'm not the ACRS.

MR. DINSMORE: Well, we've noted the concerns expressed today and we understand them and we will --

CHAIRMAN SHACK: Yes, I mean, in the 2009 Federal Register notice, you actually came up with the four days, based on the 10 to the minus seven. You came up with 18 days, based on the Reg Guide 1.117 --

MR. DINSMORE: That's correct.

CHAIRMAN SHACK: -- and presumably --

MR. DINSMORE: Well, we selected some --

CHAIRMAN SHACK: -- winged it in between, to come up with 14 days.

MR. DINSMORE: Well, the advantage of putting stuff like this in the rule is that it no

longer really comes arbitrary, because it's been discussed at public forums. It's been through the public comment, it's been --

So, even though it is a selection, it becomes a selection, as opposed to, if you just put short time and then try to put in some SC somewhere that it's -- so, okay.

All right, so, we recognize your comments on this.

MEMBER STETKAR: And again, bigger, much more significant comment, in the context of new reactors, certainly, than on the current operating fleet, but a philosophical issue for even the current fleet.

CHAIRMAN SHACK: But even the new reactors one is a -- sort of philosophical one, because, you know, they're very up front in the statement of considerations, that if you change the metrics for new reactors, they're going to have to come back in here and change this.

MEMBER STETKAR: Well, I want to talk about that. All of that discussion, we've been having side discussions through lunch on this, and I haven't studied all of the words.

I read through the statement of

considerations. All of that discussion is within the context of concerns about LRF and CDF versus LERF and CDF.

The revised wording that we just received, might change that, a little bit, but when I read through it, it seemed to, at least in the version that we had, it seemed to focus on metrics, in the sense of a measure of merit, you know, as LERF versus LRF, versus perhaps, some other philosophical measure of merit, like a quantitative health objective or, you know, early fatalities or something.

They didn't seem to address this particular numerical values.

MR. DINSMORE: Well, there is actually tucked away, in many -- one of these mini-paragraphs, something about, if we use LFR, which would be -- might be a full decade lower than increases in LERF, that we might use a factor of 10 lower.

It's certainly not in the 14 days, because I don't think it was ever really discussed within the --

MEMBER STETKAR: Not on the 14 days.

MR. DINSMORE: Yes, it's been kind of discussed with this, but you're probably right, that it was mainly, "Well, we're going to use the new LRF,"

and --

MEMBER STETKAR: I read through that stuff and I thought about it, and at least my impression, might not have been the intended use of the words. My impression was discussions over LRF versus LERF and somehow, within that context, about how well can we use -- it's hooked into thermal hydraulic models, how well can we calculate LRF versus LERF, and things like that, as a measure of merit, but not the measure of that measure of merit, the significance of that, you know, the numerical values.

Now, I might have misinterpreted the intent of the words, and where they are, but --

MR. DINSMORE: Well, we certainly are now, very aware of that problem, and it kind of permeates through it, and we'll work on that.

MEMBER ABDEL-KHALIK: You know, aside from the relationship between this time duration and the associated estimated value of additional risk, this number has to be a reasonable number, right?

I mean, whether it's an old plant or a new plant, it seems to me that specifying anything less than, you know, 72 hours as being acceptable, would be unreasonable.

MEMBER STETKAR: You mean, reasonable for

people to do -- for people to -

MEMBER ABDEL-KHALIK: Reasonable for people to ■-

MEMBER STETKAR: Oh, fix the problem, oh, yes.

MEMBER ABDEL-KHALIK: Right.

MEMBER STETKAR: No, I'm certainly not lobbying for zero, at all.

MEMBER ABDEL-KHALIK: Right.

MEMBER STETKAR: On the other hand, I think that if a specific value is included in the rule, rather than left to determination, you know, on a plant specific basis, according to some regulatory guidance, I think that the justification for that specific value should be well thought out and reasonably consistent across the board from the currently operating reactors, three new reactors, given our understanding of what the core damage frequencies and risk estimates might be, from those new reactors.

MEMBER ABDEL-KHALIK: Well, that was the point I was trying to make, that you may not be able to justify even 72 hours, but you would --

MEMBER STETKAR: You might not to -- philosophically, I don't like seeing numbers and

rules, but --

MEMBER ABDEL-KHALIK: Well, you've got to have a reasonable number, to allow people to do repairs.

So, if you're going to specify a number at all --

MEMBER STETKAR: If you're going to specify a number, it's a difficult thing to do.

MEMBER ABDEL-KHALIK: Right.

MEMBER STETKAR: It is. This is --

MEMBER ABDEL-KHALIK: But I would be happy -- I'd take 72 hour time, if you had to specify a time. That would be okay for both current and new reactors, based on --

MEMBER STETKAR: Just as long as --

MEMBER ABDEL-KHALIK: -- how long they take to respond.

MEMBER STETKAR: -- that that core damage frequency alone might be higher than the sum total of the core damage frequency from everything else, during all modes of operation, that's qualified --

CHAIRMAN SHACK: We can always count on seismic.

MEMBER RAY: As long as I'm here, you can, yes.

MR. DINSMORE: But these are similar reactors. I mean, these aren't really, completely different --

MEMBER STETKAR: We've already established that, for example, some of the passive plant designs, which qualify as a similar reactor, you know, in terms of pressures, materials, structural design, things like that.

So, that was a question this morning, that the passive designs would apply as a similar reactor.

MEMBER ARMIJO: I didn't get that. I didn't get that.

MEMBER ABDEL-KHALIK: But the implied assumption, in your argument, John, that in all cases, for new reactors, that a failure of one of these pipes would lead to core damage, but that's not necessarily true.

MEMBER STETKAR: That's not necessarily true. That's why -- but this is a risk-informed design specific or plant specific analysis.

Now, I'm not saying that --

MEMBER ABDEL-KHALIK: So, specifying, you know, three days, 72 hours, doesn't necessarily --

MEMBER STETKAR: But particularly new reactors, it might be 45 days, if you can do the

analysis to justify that 45 days is appropriate.

MEMBER ABDEL-KHALIK: Right.

MR. COLLINS: Now, there's also -- be careful now, there's also the Commission direction, that you're suppose to be able to mitigate these events.

PARTICIPANT: Be able to mitigate it, right.

MR. COLLINS: You can't just -- you know, I mean, if you just did a risk analysis, you could probably walk away from this, if it was just -- if you are doing a risk based regulation, you might be able to just walk away from large break all together.

So, at some point, we have to put a back-stop, as to how much time you're going to give them to cover, reasonably.

MEMBER ABDEL-KHALIK: Well, I'm arguing the other side, actually, that you know, specifying a time, like four days, doesn't automatically imply that you're giving them a green light to increase core damage frequency by one times 10 to the minus seven, because even if you have an event of this type, that doesn't automatically mean that you're going to get core damage.

PARTICIPANT: At all.

MR. DINSMORE: But it would permit them to operate in a configuration --

MEMBER STETKAR: Without doing an evaluation to show what the risk contribution from that is, right?

MEMBER RAY: John, let me interject something.

MEMBER STETKAR: Okay.

MEMBER RAY: Because I said something earlier that was really not applicable, I think.

This 14 days is in a 12 month period and it's for any reason that would put you outside the acceptance criteria, right?

MR. DINSMORE: Outside the ability to demonstrate that you can mitigate the LOCA, yes.

MEMBER RAY: Not demonstrate and meet the acceptance criteria.

So, if I'm an inspector, I'm going to say, "Well, of all these things that represent the configuration that does demonstrate it," any time that anything isn't available, or doesn't comply with that, because of its unavailability, that counts against your 14 days, which is not the same as the -- what I was saying before, which was the 72 hours that people think of as diesel generators and stuff like that.

MEMBER CORRADINI: I didn't understand what you just said, Harold. I apologize.

MEMBER RAY: In the configuration -- the 14 days is in a 12 month period, and it applies to the entire plant operating configuration that you're talking about.

MEMBER STETKAR: Right.

MEMBER RAY: And of that, there are many pieces, not just a diesel generator, not just this, not just --

MEMBER CORRADINI: Any one of those things could very well be --

MEMBER RAY: Yes, so, I mis-characterized what I said. That -- I'd have to think about it more, to decide if 14 days cumulative for --

MEMBER STETKAR: Everything.

MEMBER RAY: -- everything that's involved in the configuration --

PARTICIPANT: More restrictive than your 72 hours.

MEMBER RAY: I have no idea what that means, John, that's my point.

MEMBER STETKAR: Well, but in principle, if you needed four accumulators to mitigate this event, in a deterministic sense, you could have an

accumulator out for 14 days, the implication being that if you had a large LOCA during that period, you would melt the core.

MEMBER RAY: I'm assuming that there are 20 things that are required to --

MEMBER STETKAR: Mitigate.

MEMBER RAY: -- to represent the configuration, plant operating configuration.

MEMBER STETKAR: Is failure, in your sense, is failure an `or' or an `and' gate? You need failure of all 20 of those?

MEMBER RAY: No, I'm just reading the words --

MEMBER STETKAR: Or any one of those?

MEMBER RAY: Like a lawyer, I told you I was, with reading.

MEMBER CORRADINI: That's what I was going to figure you were trying to --

MEMBER RAY: It just says, "Operation in a plant operating configuration, not demonstrated to meet the acceptance criteria."

Well, I guess I would say, are you talking about just one of many plant operating configurations, not demonstrating to meet the acceptance criteria, or are you talking about any plant operating

configuration, not demonstrated to meet the acceptance criteria, because if it's the latter, then any one of many things can put me outside that configuration.

MR. COLLINS: That's correct.

MEMBER RAY: If you're talking about a plant configuration, which is one of many, now, you're only just talking about that one, which is what he was talking about.

MEMBER ABDEL-KHALIK: Rather than the cumulative total.

MEMBER RAY: Right, so, I would say again, putting my lawyer hat on, which I've had to do many times in my life, that's an ambiguous statement, because I don't know what you're talking about, just one configuration of many, or you're talking about anything that's not the configuration demonstrated to meet the acceptance criteria.

MEMBER ABDEL-KHALIK: But let me just expand on Harold's comment. The example that was given by John, that you can isolate an accumulator for 14 days, does that mean that nothing else is allowed to go wrong for the next --

MR. COLLINS: That is exactly what that means, yes.

MEMBER RAY: It's not what it says, but

that's what it means, and I thought that's what you meant.

MR. COLLINS: I think it does say that. It encompasses that, and it's --

MEMBER ABDEL-KHALIK: It's the difference between `a' and `any', in the first line.

MEMBER RAY: Yes.

MEMBER ABDEL-KHALIK: That's where the difference is.

MEMBER RAY: Well, what Said and I are trying to point out to you is, somebody could really read that to mean, you're talking about a configuration of a number, and you're just speaking of that one, a plant configuration not demonstrated to meet.

MR. COLLINS: I mean, it would be clear, if it said, operation of any plant configuration.

MEMBER RAY: Right, can't meet -- can't cumulate to more than 14 days. That's what I think you mean. That's not the way I was thinking about it originally.

MR. COLLINS: I don't know if --

MEMBER RAY: Hang on, John.

MR. COLLINS: I'm just not sure if that one just would do the opposite of what you're intending.

MEMBER ABDEL-KHALIK: Yes, you could read it either way.

MR. COLLINS: Yes, I think if I put an `any' in there, that might specify any particular one, as opposed to this, which I think --

MEMBER RAY: Okay, all right, I hear you.

MR. COLLINS: Okay?

MEMBER ABDEL-KHALIK: I mean, you can replace `an' --

CHAIRMAN SHACK: The `a' is called an indefinite article for a reason, right?

MEMBER ABDEL-KHALIK: If you replace the `a' with `all' --

CHAIRMAN SHACK: No.

MEMBER CORRADINI: I'm not sure what you meant now. I thought all that you meant --

MEMBER STETKAR: That's what I wanted to ask the PRA guy.

MR. COLLINS: Say, you needed five pieces of equipment to mitigate an event, a break larger than the TBS. If any one of those pieces is out, you can -- that counts against your 14 days.

If all five of them are out at the same time, that only counts once. Right?

MEMBER RAY: Yes, it does, but on the other

hand, if each of them was one for three days, and that exceeds your 14?

MR. COLLINS: Yes.

MEMBER RAY: We all agree on what you're trying to do, okay.

MR. COLLINS: Okay.

MEMBER RAY: And just we ought to make sure, everybody agrees, but the --

MEMBER STETKAR: I think the intent is to -- right now, in practice, it says you're allowed to operate the plant four percent of the time, my interpretation, anyway, you're allowed to operate the plant four percent of the time, when you cannot mitigate this LOCA.

MR. COLLINS: That's correct.

MEMBER STETKAR: So, it's that 96 percent of the time --

MEMBER RAY: When the configuration isn't --

MEMBER STETKAR: Ninety-six percent of the time in the year, as long as all the equipment works perfectly, you can mitigate the LOCA. Four percent of the time, you're allowed to be in a plant operating configuration, where you cannot mitigate this LOCA, for whatever reason.

CHAIRMAN SHACK: Okay, we all agree that that's the intent. The question is, whether the language says that, and I think the `a' article is the one you want, but --

06 I, certainly, reading the words, came away with my four percent, in the interpretation.

MEMBER RAY: I originally interrupted because that wasn't what I had attributed this to mean.

I thought we were talking about any component for 14 days, any one of the five components, for 14 days. That's not what we're talking about. So, I withdraw my comparison to the 72 hours, because I don't think that applies.

MR. COLLINS: But it does --

MEMBER RAY: Because that applies only to each --

MR. COLLINS: Yes, each of the components.

MEMBER STETKAR: But remember, under your 72 hours, you're not removing sufficient capability to mitigate the accident. You're only reducing the margin.

MEMBER RAY: I'm not clear --

MEMBER STETKAR: It's a different concept.

MEMBER RAY: It may be, but when it comes

to things being broken and fixing them, it's applicable, from an operator stand point.

MEMBER STETKAR: Sure, that's right. That's right, you put yourself in an LCL, you want to make sure it's --

MEMBER RAY: If you tell me it's for 14 days, for a single component, well, I'll talk to you next week, when we're all back here together, and you'll decide what to do.

06 You've operated a plant --

MEMBER RAY: Right, but I mean, 72 hours, we better do it before we go home today.

MEMBER CORRADINI: But can I just clarify it, since I thought I got it, but now, I'm not sure I've --

MEMBER RAY: You're not as confused as you imagine.

MEMBER CORRADINI: So, to take it, as it is with the current rule, and use the accumulator example, you have a three-day window.

MEMBER RAY: Yes.

MEMBER CORRADINI: Okay, so, we're changing -- now, I'm going to say this, it's probably wrong, we're changing the probability of a core damage from one 10 to the minus seven, to four 10 to the minus

seven.

I have the same frequency of a large break. I've allowed three days to be out of compliance --

MEMBER STETKAR: Well, I've got to ask you a question.

MEMBER CORRADINI: And I've expanded three days, 3.5 days --

MEMBER STETKAR: Well, except for the fact that this is cumulative and the way that that 72 hours is currently applied is on approval -- on a per-event basis.

In principle, people, don't do this, but in principle, they could take it out for 72 hours, put it in for 10 minutes, take it out for 72 hours.

MEMBER RAY: Right, they're going to break for 10 minutes or 10 days, but then --

MEMBER STETKAR: Or 10 days, yes.

MEMBER RAY: But also, my -- wait a minute, there is also the fact that there may be other components than the accumulator, which have to be added, in this model, and not in the tech spec model.

MEMBER CORRADINI: Correct.

MEMBER RAY: All right, that's a big difference to me.

MEMBER CORRADINI: No, I understand that, but the only reason I'm doing that is, that in some sense, this argues against John's original characterization of this, because this could be potentially much more restrictive --

MEMBER ABDEL-KHALIK: Yes, that's what I got.

MEMBER RAY: Depending on the number of components you've got.

MEMBER ABDEL-KHALIK: But then it just depends. I mean, it doesn't necessarily have to be restrictive, if you're talking about one component, taking it out of service for the entirety of the 14 days that you're allowed.

MEMBER CORRADINI: But I mean --

MEMBER RAY: Well, but then, you'd be stuck for a year or something.

MEMBER CORRADINI: Right.

MEMBER RAY: I mean, that's a bad position to be in.

CHAIRMAN SHACK: You're losing your power upgrade for a year? That would smart.

MR. DINSMORE: Well, actually, the second phrase -- adding that second phrase would allow them to come with emergency request and not have to get an

exemption.

MEMBER STETKAR: That's right, the second bullet there allows people to come in and either extend the 14 days to 30 days on a plant specific, you know, risk-informed plant specific basis, or come in, as you said, under emergency request for, you know.

MEMBER ABDEL-KHALIK: So, having the second bullet, really allows you to be -- to tighten the requirement on the first one.

MEMBER STETKAR: No, if you're an operator, you're going to come in and say, "Oh, ghee," --

MEMBER ABDEL-KHALIK: I mean the regulator, not the --

MEMBER STETKAR: Not if the -- the rule says --

MEMBER RAY: The key is proposed alternative site.

MEMBER STETKAR: The quote from the rule says --

MEMBER RAY: You're not going to propose --

MEMBER STETKAR: -- a short time is either a total of 14 days in a 12 month period, or an alternative proposed by the licensee and approved by the NRC.

MEMBER ABDEL-KHALIK: Right, right.

MEMBER STETKAR: If I'm a licensee, I'm not going to propose 72 hours.

MEMBER ABDEL-KHALIK: I fully agree, but the rule can say 72 hours, and somebody can come back and say, "I want 14 days, I want a month, I want two months."

MEMBER STETKAR: That's true.

MEMBER ABDEL-KHALIK: And if they can demonstrate that that's acceptable, then, more power to them.

MEMBER CORRADINI: Maybe we went over this earlier, I guess I -- if you did, I missed the answer. How did you arrive at 14 days?

MR. DINSMORE: There is an SRC --

MEMBER CORRADINI: Did you answer that?

MEMBER STETKAR: Yes, we did.

MEMBER CORRADINI: Okay, I'm sorry.

MEMBER STETKAR: He'll explain.

CHAIRMAN SHACK: It's not the clearest explanation in the world, but it's -- there is an explanation.

MEMBER CORRADINI: Okay, fine.

CHAIRMAN SHACK: I mean, I'm not even sure how you're going to come up with an acceptance criteria for the second bullet.

I mean, if you had a real criteria, you'd have built it into the -- into the rule.

MR. DINSMORE: Yes, sir, well, that's why we didn't want to just say that and go ahead and start getting submittals and trying to figure it out.

MEMBER CORRADINI: So, you want to keep it big enough that they be afraid to ask?

MR. DINSMORE: No, we wanted to keep a nice, crisp alternative and then provide them with this --

CHAIRMAN SHACK: And then you can argue over the alternative.

MEMBER CORRADINI: A vague exit clause.

MR. DINSMORE: Okay, we'll go onto the next slide.

Large release frequency, the comment was large release frequency should not be in the rule. New reactors should use the same criteria as 1.174.

We agree, the LRF concept shouldn't be in the rule, because it's still being evaluated and it would be premature to use it in the rule. The rule was changed to -- we deleted large release frequency and we just left the same criteria, small and minimal -- I'm sorry, very small risk increases for new and operating reactors.

But we did add this extra thing from the new reactors guidance documents, and I checked earlier and Mr. Stetkar is right, that it does apply to every, to the minimal and to the changes they request, but we've added the criteria and the changes will not otherwise result in the significant decrease in the level of safety, otherwise provided by the certified design.

So, they got to meet -- the way the rule is now written, they have to meet very small, if they do it on their own, they have to meet minimal, and they would always have to satisfy this criteria.

What this means in practice, again, is a little uncertain, but --

MEMBER STETKAR: Again, I come back to -- I could -- except for the 14 days, I couldn't find anything in the language of the rule, that caused me problems thinking about either currently operating plants or new reactors, because the words in the rule, things like significant decrease in the level of safety, is appropriately vague and will be sorted out, eventually, when the risk metrics issues are resolved.

It's in the statement of considerations, where the specific numbers are in there, and where people then can start inferring what is small enough

or not big enough or something like that.

MR. DINSMORE: Yes, we'll revisit that.

MEMBER STETKAR: And this one is pretty clear. It says even for a self-approved changed, I have to be able to demonstrate that I have not significantly decreased my level of safety, whatever that means.

MR. DINSMORE: And the SOC actually says, well, that if we want new criteria, we might change the rule later on. It's tucked away in there.

MEMBER STETKAR: But again, that's in the context of LRF and LERF, isn't it?

MR. DINSMORE: Yes, well, yes. Moving on, comment PRA-3, minimal comments were that it's not used in Reg Guide 1.174. If it is used, it should be defined in the rule, which is kind of contrary to what we think, too.

It appears to have a very small -- it appears to have the same value as very small. The responses are, "Well, we agree that it's not in 1.174," but Reg Guide 1.174 does not address self-approval. If it is used in the rule, it should be defined.

We disagree. The rules often use descriptive criteria with quantitative guidance

document for a number of good reasons. Minimal is defined in the SOC to be 10 to the minus seven and 10 to the minus eight. When I wrote this slide, I wasn't thinking about the new reactors. So, we didn't change the rule.

The definition of the values are consistent with -- well, the definition of values for minimal are consistent with the self-approval guidelines in Reg Guide 1.205, which is the self-approval for making changes to your fire protection program.

However, the comment, minimal, appears to have the same value as very small. We agree that some confusion was possible, because the minimal criteria in the rule included the phrase `minimal compared to the overall plant risk'.

The SOC was talking about, well, it's 10 percent of what we'd normally permit and then later, it said it's 10 to the minus seven, but if you take 10 percent of small, you're down to very small.

So, anyway, so, the use of that phrase, `minimal compared to the overall plant risk' implied that there could be different values for minimal, which I guess, you kind of want.

MEMBER STETKAR: I believe that there are.

CHAIRMAN SHACK: But that's a discussion for another day.

MEMBER STETKAR: No, no, even for currently operating plants, there are differences on a plant specific basis, of what is a itsy-bitsy teeny-weeny, to use a contribution to overall plant risk.

MEMBER CORRADINI: Well, there is another --

MEMBER STETKAR: You know, so, you know, this notion that what is small, is small enough on an absolute numerical sense, applying to everyone, does philosophically apply to both new and existing, currently operating reactors.

MR. DINSMORE: Well, minimal, initially -- many years ago, came up, because licensees were saying, "Well, there will be changes that will not change risk, and you're telling us we have to make a submittal, we have to do a risk evaluation," and the big example that was used a lot was that you slow up your value opening time.

And so, we said, "Well, no, that's probably not right," and so, there came this thing, minimal, and then -- but once it was there, it had to get a number, and ACRS, actually, we took it out of the last one and -- the last one that came through

just said, "Well, you're going to have to submit the changes that you would normally submit," and ACRS reacted very badly to that and so, they said, "Well, you need a risk-informed criteria."

So, we put minimal back in, and --

MEMBER STETKAR: Why, again, I was thinking about something else. Why the second bullet? Why was the rule changed to remove the phrase `compared to overall plant risk', which implies a plant specific comparative analysis, rather than --

MR. DINSMORE: A part of the -- very small is the same number for all plants, and again, this was -- well, if it's going to say `compared to overall plant risk', it makes it look like -- it makes it look like there are different values, and again, I wasn't aware that there was some thought, there should be different values.

We didn't think it would improve the situation, and it just made life confusing and people could come in and start arguing, "Well, my minimal should be this, instead of that, because it's compared to my overall plant risk."

And so, we're proposing to take it out --

MEMBER STETKAR: But again, this is --

CHAIRMAN SHACK: In 1.174, the lines are

flat.

MEMBER STETKAR: Yes, I know that.

CHAIRMAN SHACK: You may not like it, but they are flat.

MEMBER CORRADINI: I think he doesn't like it. I think we're clear on that point.

MEMBER STETKAR: But I will also come back to the fact that this is a voluntary submittal, that's done on a plant specific basis.

We're not going to have the PWR Owners Group come in and do this for every generic PWR, in the country.

So, as long as I'm making a plant specific submittal, a risk-informed plant specific submittal, why can't I not demonstrate what is very small or minimal, from my plant, using the available guidance in 1.174 as justification, or whatever?

You know, why --

CHAIRMAN SHACK: That would lead you to the same values.

MEMBER STETKAR: Fine, fine, for a currently operating plant. Why?

CHAIRMAN SHACK: Okay.

MEMBER STETKAR: My concern is having a specific numerical value wired in there, with the

implication that it applies to every single operating reactor, regardless of its vintage, or perhaps, a currently operating plant --

CHAIRMAN SHACK: Oh, I see.

MEMBER STETKAR: -- that has been substantially back-fit, such that its risk -- suppose somebody spent $100 million, and reduced their plant specific risk, down to 10 to the minus six, five, you know, seven, something like that.

MEMBER ABDEL-KHALIK: So, your objection is that -- to minimal equals 10 to the minus seven?

MEMBER STETKAR: Exactly, and that --

MEMBER ABDEL-KHALIK: Applied to current operating reactors?

MEMBER STETKAR: Applied to any reactor.

MEMBER ABDEL-KHALIK: Any reactor?

MEMBER CORRADINI: Then, I guess I'd have a problem with what you're saying. I can understand it applying to new reactors, because that leads us to your whole generic philosophical argument.

But to current reactors, isn't it pretty well defined and clear, and why start mudding the waters?

MEMBER STETKAR: If I'm a currently operating reactor, it should be very easy then, for me

to demonstrate that what I'm doing satisfies all of the current regulatory guidance, without a specific numerical in there.

There are things I can point to, as a currently operating reactor.

CHAIRMAN SHACK: Well, at the moment, there is not going to be -- there's only minimal, and the only thing that's questioned is whether it should be compared to overall plant risk or not, and they're taking it out, which --

MEMBER STETKAR: They're taking it out.

CHAIRMAN SHACK: -- I like, and you don't.

MEMBER STETKAR: And leaving minimal.

CHAIRMAN SHACK: You know, perhaps, we need to revise 1.174, to be consistent with the new -- whatever we -- you know, since old reactors do, in fact, have variable risk, that's a different question.

MEMBER STETKAR: That's a different question. I would expect when the new reactor risk metrics issue is sorted out, I wouldn't be surprised if there were some changes to 1.174, you know, once you merge those things together, because somehow, there has to be a continuum, you know, that applies to -- I'm not aware of all the reactors in the U.S., but I know some foreign reactors that have done

substantial modifications to an old plant design, such that their core damage frequencies are rather low, you know, even though you might put it in the currently operating reactors category, and certainly, what's small for them, very small or minimal, is much different than another plant that hasn't done any modifications.

There are certainly currently operating plants that have a lot more installed equipment, and even in the United States, where there is, in deed, a substantial variability in core damage frequency, compared to other plants.

MR. DINSMORE: We are, again, just going to take out that phrase, because we thought it was making life more confusing than it needed to be.

CHAIRMAN SHACK: There will not be universal agreement.

MEMBER CORRADINI: And when you leave the room, there will be a fight developing.

MEMBER STETKAR: This is a Subcommittee meeting and you get to hear individual members' opinions. You know, eventually, a Committee letter will be written, when you hear the --

MEMBER ABDEL-KHALIK: I think if you say that the rule will not apply to new reactors, then

removing this statement would have no consequence.

MEMBER CORRADINI: I guess I'm --

MEMBER STETKAR: You know, this philosophy, and there's practicality, and I'm, right now, expounding on philosophy.

MEMBER CORRADINI: We sense that.

MEMBER STETKAR: Practicality for new reactors is actually, a real concern.

MR. DINSMORE: I guess I'll move on.

CHAIRMAN SHACK: We've exhausted this one.

MR. DINSMORE: Comment, the next comment, periodicity of two refueling outages should not be in the rule, maintenance and upgrading according to the ANS/ASME standards should be acquired instead.

This was kind of an odd comment, because actually, they were talking about this part in the rule that requires you to periodically re-assess your change in risk, and they didn't seem to be -- we didn't get any comments saying, "You shouldn't do that," unless you interpreted that last comment to be, just take that whole requirement out, and rely on the ANS/ASME standard, which they might have meant.

But anyway, we disagreed that -- that should be ANS/ASME standard describes how a PRA is to -- we disagree that we should just rely on that in the

rule, because the ANS/ASME standard just describes how a PRA is to be maintained and updated. The rule requirement is on how a properly maintained and upgraded PRA is to be used to support the risk-informed evaluations required by the rule.

We did, however, agree that when you've got similar guidance that's applicable, it should be applied whenever it's possible, and so, we went and realized that the 50.72 has a four-year PRA update. So, we changed it to refueling outages, just to go -- to be consistent with that.

Comment five, very small shouldn't be changed, departs from and conflicts with Reg Guide 1.174, acceptable increases should be small, and then we -- this isn't the same commenter, of course.

We got another comment, no increase should be allowed, because current ECCS analyses are non-conservative and under-estimate risk.

MEMBER ARMIJO: Well, I guess where that came from.

MR. DINSMORE: So, one at a time, very small departs from and conflicts with Reg Guide 1.174.

Well, we agree that it does depart, because it doesn't use all the options. We disagree that it really conflicts, because very small is in

there, and we would use all the guidelines associated with very small.

For example, we wouldn't really required you to give us a good estimate of the -- of your CDF and LERF.

Acceptable increases should be small. We disagreed because beyond disagreeing with the Commissions' direction to use very small, they provided no new information that would cause the staff to change the acceptance criteria. That's from the lawyers.

Yes, the Commission knew what small was and very small, and they chose to put very small in there, and there was simply, disagreement that it was the right thing to do.

Then the one, no increases should be allowed, we disagreed, because any problems with ECCS analysis should be resolved by changing the analysis, not by changing the acceptance criteria. I'm sorry, I just confused this.

Getting back to -- okay, I'm back to my right slide. So, we're going to leave small -- very small in there, and one of my favorite topics.

Cumulative change in risk evaluated -- the comments were that cumulative change in risk

evaluation is not needed, is not needed used in the other risk-informed applications.

We disagree that the cumulative change in risk evaluation is not needed to ensure that enable changes made over time do not result in a significant increased risk. We disagree that cumulative risk, sequential changes over time is not considered in every risk-informed application, although resolution is application specific.

Over the years, I've developed a list. If you guys would like to go through the list, I can do it, but we actually do deal with it, but it does change, depending on which application you're looking at.

MEMBER ARMIJO: But that's really, your standard practice, then? This is the normal process?

MR. DINSMORE: Yes, Reg Guide 1.174 has different direction in it, but the general direction is keep -- or take care of it.

06; It doesn't explicitly require you to total it up, right?

MR. DINSMORE: To calculate it, always, but it does take -- it says --

MEMBER STETKAR: It says you need to consider it, or something.

MR. DINSMORE: Watch it, take care of it.

CHAIRMAN SHACK: Consider it, I think is the word they use.

MR. DINSMORE: The rule has not changed. Actually, I'm kind of happy with this one too, because what we did is we took the wording from NFPA-805.

NFPA-805 has a very nice write-up on cumulative and why it's -- it should be addressed and we didn't -- no NRC people -- no PRA/NRC people wrote 805.

So, they came up with this all on their own. So, we took the wording right of NFPA-805. We had to tweak it a little, tiny bit, and put it in here, and we -- what we're planning on doing is, however we eventually deal with it in NFPA-805 applications, we'll simply use it -- deal with it the same way, here, and that's the plan.

We have not yet figured out how to do it in NFPA-805.

I'll keep going. Okay, this is my last slide, actually, so, I'm pretty far ahead of schedule.

There were a bunch of minor PRA comments, should not require risk-informed evaluations in all 50.59 changes. That was a very complicated area in the cross-references. Somebody figured it out and it

did imply that. So, we just corrected that.

Should not use -- should not require use of PRA that addresses all modes and initiators. This is a very common comment we get, on pretty much everything.

The response is, we disagree. There is no change. Normal risk-informed scope applies, if the contributor is not significant, it may be treated with qualitative arguments. No need for reporting self-approved changes, other than current 50.59 reports.

The response is that we disagree. We didn't change the rule, because some changes enabled by 50.46a will no longer affect the design basis. That might be the wrong word, and may not be reportable under 50.59. So, we didn't change the rule.

Existing functions will always be able to realistically mitigate a double-ended guillotine LOCA. This was similar to that other comment. We just said, no, you have to demonstrate it.

CHAIRMAN SHACK: Faith-based regulation.

MR. DINSMORE: The rule should be changed to clarify that changes to tech spec's must always be submitted. We agree, and we changed the rule to address that, and that was the major comments and how

we reacted to them and the changes we are proposing.

So, two rule changes, two minor rule changes and the rest, not. So, I'm actually 20 minutes early.

CHAIRMAN SHACK: You're ahead of schedule.

(Off the record comments.)

CHAIRMAN SHACK: Okay, well, if there are no further comments or questions for Mr. Dinsmore, we can move on.

MR. DUDLEY: Do you want to move on, or do you want to take a break?

CHAIRMAN SHACK: Why don't we just take, yes, we'll take a break and then we can come back and finish up.

MR. DUDLEY: I'm waiting for the leak detection staff member to come in. He should be here shortly.

CHAIRMAN SHACK: We'll take a break until 2:25 p.m.

(Whereupon, the above-entitled matter went off the record at approximately 2:10 p.m. and resumed at approximately 2:25 p.m.)

CHAIRMAN SHACK: Back to you for, I guess --

MEMBER STETKAR: Or just coming back to --

do you remember the Hawaiian Airline 737 flight, the photograph of the people sitting there with the wind -- it's a wonderful photograph of, you know, what can happen, in terms of structural failures.

CHAIRMAN SHACK: Codes that have far smaller margins than the ASME code.

MR. DUDLEY: Okay, I'm going to address two miscellaneous public comments that we got.

The first was a comment on the enhanced leak detection requirement that we have in the rule.

The commenter said we should not require enhanced leak detection for larger than TBS piping, because leak detection methods can't determine if leakage is from larger than TBS or smaller than TBS piping.

The commenter also said, existing leak detection requirements are adequate, and our response, though, it's unnecessary to differentiate between less than TBS leakage and greater than TBS leakage, as long as all the piping larger than the TBS is covered.

And we believe that enhanced leak detection can provide some additional protection against greater than TBS LOCAs and it would be appropriate because other requirements are reduced.

So, the leak detection requirement is

retained in the rule, but in the public meeting, when we discussed with the industry, this requirement, many of them thought they met the requirement or the language in the rule.

So, what we did is, we added -- it wasn't clear to us. So, we added a requirement that when a licensee initially applies to adopt 50.46a, that they demonstrate the enhanced capability in their initial application, and what we mean is that their capabilities are consistent with the program described in Reg Guide 1.45 Revision 1, which is May 2008.

Any questions on leak detection?

MEMBER ARMIJO: Physically, what do they have to do, to demonstrate enhanced leak detection capability?

MR. DUDLEY: Physically?

MEMBER ARMIJO: Yes, do they have to install new equipment, new sensors, change the location of leak detectors, or is it -- if they just comply with current regulations, they're okay?

MR. HARDIES: Bob Hardies. The new -- the enhanced leak detection, it's actually been implemented at all the PWRs, in response to the reactor vessel head issues, and it involved trending. It was a lot of programmatic work, which was trending,

you know, hour to hour, and then getting baselines and tracking differentials against baselines.

Then it was taking a more holistic approach to leakage, paying attention to humidity sensors and beyond just some frequencies, and radiation detectors and trending some of it.

I don't know that any additional equipment was --

MEMBER ARMIJO: Yes, that's what I'm trying to understand, this comment.

MR. HARDIES: But in some cases, you know, a plant might need to -- for example, no fuel failures and the radiation detection stuff falls out --

MEMBER ARMIJO: Yes, right, right.

MR. HARDIES: -- you may have to do something a little bit different, which may involve installation of new stuff, but I'm not aware that anyone hasn't installed new --

MEMBER ARMIJO: But basically, if you detect a leak that's greater than some level, you don't really care whether it comes from a big pipe or a small pipe or a valve --

CHAIRMAN SHACK: You need to do something.

MEMBER ARMIJO: You're going to do something about it, and so, I guess I thought leak

detection was adequately covered already, and so, I understand the term of enhanced, and maybe that's -- maybe the --

MR. DUDLEY: Well, I guess, my understanding was that the Reg Guide Revision 1 was not back-fitted. It wasn't back-fitted as a requirement, and therefore, it's voluntary.

MEMBER ARMIJO: Okay.

MR. DUDLEY: I believe it may be that PWRs haven't voluntarily implemented a lot of that.

MEMBER ARMIJO: Okay.

MR. DUDLEY: And if that's the case, then they would certainly meet the requirement for them, it wouldn't be enhanced at all. It would be what they have already.

MEMBER ARMIJO: Yes, right, okay.

MR. DUDLEY: And we'll determine that when we review their application and we'll make that decision.

And the last comment, we had some comments related to petitions for rule making that are either active before the NRC or that we've previously addressed, and the commenter said that PRM-50-93 and 50-84 show that there are deficiencies in the NRC's -- in the industry's ECCS evaluation models and the ECCS

acceptance criteria, and the commenter believes that all those deficiencies should be fixed, before the NRC would implement 50.46a, which would allow licensees to make changes to ECCS designs.

In our response, we think that 50.46a relates more to the size of pipe breaks and the assumed initial plant conditions, than it does -- relates to the actual -- ECCS model requirements themselves.

Basically, it deals with analysis inputs and not the models. So, we see them as separate issues and we'll pursue them as separate issues. We'll review these PRMs and we'll determine if ECCS models are deficient.

As a matter of fact, PRM-50-84, we've included a requirement in the 50.46b acceptance criteria, or at least, we're planning to include that, to require licensees to specifically address the accumulation of crud, on their facilities.

But what we'll do is, when those petitions for rule making are evaluated and when any related rule makings are completed, we will make sure that those requirement apply to both 50.46 and 50.46a licensees, and we made no changes to the final rule, and as I said, the rule making for -- to update the

50.46b acceptance criteria is in process. We're working on the proposed rule now. Are there any questions on this slide?

(No response.)

MR. DUDLEY: I guess this completes the staffs' presentation.

CHAIRMAN SHACK: Okay, you again, will be sending us a final language version next week?

MR. DUDLEY: Yes.

CHAIRMAN SHACK: Just so we can see what that looks like.

MR. DUDLEY: And I don't think there is -- I don't think that the changes will be substantial at all, but and the one that might have been, I think I've provided you already.

CHAIRMAN SHACK: Okay, any additional comments or questions, from members? Any feedback for me, on what you think are important issues? I think I know, but just in case I'm missing something.

MEMBER ARMIJO: I think we heard John's.

MEMBER STETKAR: Do you want me to reiterate them, just for --

CHAIRMAN SHACK: Yes.

MEMBER STETKAR: Okay, three. One is the 14 day explicit tech spec requirement that's in the

rule. Two is the --

CHAIRMAN SHACK: Now, you object to that both for old plants and new plants?

MEMBER STETKAR: Yes, philosophically, yes, and I don't want to try to get into pragmatism, at this point. Philosophically, I do.

The second is the explicit numerical criteria for very small and minimal increases in CDF and LERF, that are stated in the statement of considerations, as applying to every plant, both current operating plants and new reactors, and no problems with the wording in the rule, regarding that, it's just the statement of considerations, applying those numerical values, again, in some sense, philosophically consistent -- you know, across the board, but they are a particular concern for new reactors.

And the third is the -- in the requirements during transition, that the licensee would not be required to examine indirect seismically induced failures, as part of their evaluation of -- yes, seismic vulnerabilities.

So, those are sort of my three topics.

CHAIRMAN SHACK: Mike, any additional comments?

MEMBER CORRADINI: Well, this probably was said, since I was out of it, but I think applying it to new reactors now, I don't see the benefit in doing that, unless there is some regulatory benefit to do it now, that you can't add it later.

I just don't think this is ready for prime-time, for new reactors. That would be my major one.

I think, John, I heard two parts of one, and the last one, that I would agree with John, is that some of the details, the one in particular was the indirect failures, due to seismic, or seems to be gaps that could be filled by just changing the language for -- and they're specifically directing some additional requirements.

But I think the big one --

CHAIRMAN SHACK: Well, that's almost more a Reg Guide issue, in a sense. But you know, the Reg Guide --

MEMBER CORRADINI: I think it's in the rule. I think the indirect is in the rule. That was the only thing that -- I asked John about that --

MR. COLLINS: Direct is required in the rule, but indirect is not required in the rule.

MEMBER STETKAR: Indirect is not required

in the rule. But it says, in the statement of considerations --

MEMBER CORRADINI: That's what I thought.

MEMBER STETKAR: -- explicitly says that indirect is not required.

MR. COLLINS: Right.

MEMBER CORRADINI: So, this is a question, maybe before I give comments, but this is a question.

The statement of considerations is like background. So, it's not the rule.

So, to the extent that I guess, I look at it, I guess the 14 days is in the rule, and the indirect is -- in the rule, says you don't have to consider it. That's what -- those are the two that give me a bit of pause.

Other than that, I think that the other things can be manipulated to be consistent with the rule.

MEMBER STETKAR: But in practice, people do refer to -- we've had presentations about the --

MEMBER CORRADINI: Where the statement was --

MEMBER STETKAR: Right, people refer to the statement of considerations as characterized as a Commission interpretation.

MEMBER CORRADINI: But it has to be made consistent, but within the rule itself, I think indirect is allowed to be not considered, in the rule.

MEMBER ARMIJO: Absolutely, they don't have to do it.

09 The rule does not require indirect --

MEMBER CORRADINI: So, I guess besides that and the new reactors, the new reactors concern me the most, because I just don't see -- it causes more confusion, than I think it helps.

MEMBER ARMIJO: I don't think it's of value to put the new reactors in, until we've settled the risk metrics issue.

MEMBER CORRADINI: Right.

MEMBER STETKAR: But there again, reading things in the rule, with the exception of the rule not requiring the indirect, which is a current operating reactor issue, and the numerical implications of that 14 days, everything else, in terms of my concerns related to new reactors, are those numerical values in the statement of considerations.

I don't --

MEMBER CORRADINI: They're not in the rule. They're in the statements or in the Reg Guide.

MEMBER STETKAR: Right, right, but I guess

the way I feel is that saying that the rule should not apply to new reactors, seems to me, a bit extreme, because given where the rule has progressed.

You know, the things that I'm talking about, I think need to be cleaned up for an existing -- to modify the language, existing and new reactors, with appropriate caveats in the statement of considerations, dealing with specific risk metrics, which are not in the rule.

Remember, those numbers are not in the rule.

MEMBER CORRADINI: So, you're saying something different. You're saying, if one were to deal with the 14 days and one were to deal with the indirect failures, due to seismic, and not say be silent on new reactors, but keep it relatively consistent and qualitative, it could stay as is. That's your --

MEMBER STETKAR: That's my personal interpretation, yes.

MEMBER CORRADINI: I just wanted to make sure I understood.

MEMBER STETKAR: I think saying that we should --

MEMBER CORRADINI: But see, if you go

forward with the new reactors, if you allow the rule to apply to the new reactors now, don't you -- aren't you going to get yourself all tied up in exactly the issues of risk metrics, now?

MEMBER ARMIJO: Yes.

MEMBER CORRADINI: That's the only thing --

MEMBER ARMIJO: You're kind of forcing it in.

MEMBER STETKAR: I don't believe in practice -- I will be pragmatic, that I don't believe any new -- I don't believe any design centers or COL applicants are going to adopt 50.46a at this point in the licensing process.

MEMBER CORRADINI: So, your point is, it's moot point, because nobody is going to deal with it?

MEMBER STETKAR: I am -- yes, that's my point, that ■-

MEMBER CORRADINI: I've never known you to be practical before.

MEMBER ARMIJO: But if that's the case, why don't we just put it in? Why don't we just leave it in abeyance for the time, the risk metrics --

MEMBER STETKAR: Well, the whole problem then is, you get into a situation where we, in principle, have different rules for new reactors

versus operating plants, that are --

MEMBER ARMIJO: That's exactly what we're going to do, particularly, when we get into the risk metrics. We're going to set --

MEMBER STETKAR: Not necessarily, because the risk metrics might be resolved through regulatory guidance.

You know, changing Reg Guide 1.174 or in the extreme, adopting a completing new regulatory guide for whatever a new reactor is, could resolve a lot of those numerical concerns about risk informed applications.

MEMBER CORRADINI: I don't think it's a clear-cut thing, thought, John. But just to fight back a bit, it seems to me, if you're unclear about where the risk metrics are going, and this gets promulgated with the new reactors in it, even though nobody is going to volunteer to do it, it will just create more confusion.

I'd rather just say that the new reactors --

MEMBER ARMIJO: That could be the story on operating plants.

MEMBER CORRADINI: Right, that would be, just deal with operating plants.

MEMBER ARMIJO: That would be a good job, and that would be enough, and if it turned out later, that there's a reason to extend it to new reactors, do it later, once you've solved the risk metrics.

MEMBER CORRADINI: I guess, I would agree with you, that you made a practical statement earlier, that except for --

MEMBER STETKAR: The staff has already --

MEMBER CORRADINI: -- except for one that you're -- you can think of and we saw it in the comments, none of the new reactor folks even chose to comment on it.

So, that would imply to me that they're not going to deal with it.

MEMBER STETKAR: I don't think they are, only because even a simple risk-informed application for risk-informed tech specs, has been back and forth across the board, whether or not one of the COL applicants is going to try to invoke that, and I don't know what the current thinking is, but I think it might be off the table right now, and that's somewhat more straight forward than this, in terms of trying to get through the licensing process.

MEMBER ARMIJO: But you know, that's an issue.

MEMBER STETKAR: Well, that another comment that --

CHAIRMAN SHACK: We don't to resolve the problem --

PARTICIPANT: You mean, we can't fight now? We have to fight later?

PARTICIPANT: We can fight any time. This is actually the first time we've had time to fight.

CHAIRMAN SHACK: I know, but we have to fight, all of this, together.

MEMBER STETKAR: Well, but just -- the staff has put an awful lot of effort into, I guess, trying to weave the new reactors into this, and to remove the new reactors, you know, do you need to then go out, again, for public comments on the rule? Is that a significant --

MR. DUDLEY: Not to go forward with the -- everything, but new reactors. But if you wanted to go forward with new reactors, I'm not sure to what extent --

MEMBER ARMIJO: You start modifying it, to adjust the new reactors part, as John wants, it's probably more work than to just say it's -- it's for operating plants, and limit it, at that point, for now.

MEMBER CORRADINI: I guess I wanted to understand your response.

So, your point was that if, God for bid, Heaven for bid, you actually agreed with us, and you -- some of us, and you pulled new reactors out of it, you wouldn't have to go back out for public comment.

MR. DUDLEY: No.

MEMBER CORRADINI: Okay.

MR. DUDLEY: Not for the part that we issue final.

MEMBER CORRADINI: Okay, and then, let's just go further. Let's say years pass, many years, and the new reactors that are built ■-

MEMBER ARMIJO: Are clamoring.

MEMBER CORRADINI: -- or clamoring to use this, would that be requiring a modification rule, which requires rule making, or is it -- process-wise, you start over, I assume.

MR. COLLINS: I think so.

MR. DUDLEY: Yes, I think so. It would be so old and stale, I think we'd just have to start over.

MEMBER CORRADINI: Okay.

MR. DUDLEY: With the proposed rule and -- right.

MEMBER CORRADINI: We have members of the public. I'm curious what they think.

DR. WALLIS: You don't want to hear what we think.

CHAIRMAN SHACK: Said?

MEMBER ABDEL-KHALIK: I really have no additional comments. I think the concerns have been raised already.

MEMBER ARMIJO: Yes, same thing, I think the real technical contribution we've made is this issue of indirect, indirect damage. Everything else is kind of programmatic.

MEMBER ARMIJO: Same thing.

CHAIRMAN SHACK: I guess, we can adjourn, all right.

MR. DUDLEY: Wait, our next -- we meet with the Committee, the full Committee, on October 7th. I think we have two hours, is that right?

CHAIRMAN SHACK: Yes.

MR. DUDLEY: Yes, and so, what -- can you -- what sort of presentation would you like? What should we focus on? I guess we would present for about an hour, right?

CHAIRMAN SHACK: Right. It would the overview, of course, that we had. I actually think,

since the indirect is going to be a major topic, any discussion that you could have, to strengthen your position, that you don't need to do the indirect, I think should be --

You know, so, to me, it -- I don't think there's a real disagreement on the new reactors. We could -- you know, we will discuss -- I think we all understand the problem of, you know, whether you're going to re-write the rule, if we change the thing, or if we leave them out now, you know, there are various ways to handle it.

I think everybody, staff, even the current -- they all recognize the problems with new reactors. The best way to handle it, you know, maybe someone -- I'm not so concerned about that, at the meeting, and I am -- the indirect, I think, would be a major change in the rule, and you know, a defense of the current position, or the best defense that you could mount, would be a contribution.

MR. DUDLEY: Best and final offer.

MEMBER STETKAR: Not on the rule, but I mean, you would have to pull back the draft Reg Guide that's out on the street. It's --

CHAIRMAN SHACK: Actually, I can't find -- you know, everybody says it's in the rule language.

I can't find it in the rule language.

MEMBER ARMIJO: Which one, the 14 days or --

CHAIRMAN SHACK: No, the indirect.

MEMBER ARMIJO: Maybe by inference --

MEMBER STETKAR: By inference, I think, because it's not specified --

CHAIRMAN SHACK: You know, it refers to 1903.

MEMBER STETKAR: Now, honestly, I couldn't find it in the rule language, that says you don't --

CHAIRMAN SHACK: Yes, I mean, I searched for every occurrence of seismic in the rule itself, and --

MEMBER STETKAR: And indirect.

CHAIRMAN SHACK: Well, I just looked for seismic, and then -- just in case it was mis-spelled, when they get to indirect.

MEMBER STETKAR: I couldn't find it either, Bill. I looked.

MR. COLLINS: Certainly, in the statement of considerations --

CHAIRMAN SHACK: The statement of comment -- or statement of consideration, certainly, yes, you know, there's a bold statement there, but the actual

rule, but again, because the statement of considerations is --

MEMBER ARMIJO: Is not the regulation.

MR. COLLINS: I guess, the reg, actually, we just say that you need to show the applicability of --

CHAIRMAN SHACK: Right.

MR. COLLINS: Yes, that's why we need to be clear about that, however it comes out, in the end.

CHAIRMAN SHACK: However it comes out, yes.

MR. COLLINS: Yes, we'll need to be clearer.

CHAIRMAN SHACK: But to me, that -- I think that is going to be the major technical issue, you know.

In retro -- if we look back at the November 16th letter, I think you've addressed all of the questions there. You know, we ask for an applicability to the specific plants.

And so, this indirect is essentially, a remnant of that, but the other -- all the other issues in that letter, I think, have basically been addressed. We can discuss among ourselves, whether we're happy with the address, but to me, the major remaining technical issue is the indirect.

Again, that probably should be clarified in the rule language, and any discussion of why that's acceptable, is probably --

MEMBER ABDEL-KHALIK: And of course, the 14 day thing.

CHAIRMAN SHACK: And the 14 days.

MEMBER ABDEL-KHALIK: Right, that automatically translates into a green light for changes that result in increase in core damage frequency of three times 10 to the minus seven, I think people will be pretty concerned about that, well, four times 10 to the minus seven, excuse me.

MEMBER ARMIJO: For operating plants?

MR. COLLINS: For 14 days, the concern is that we're specifying a specific number, or the concern is with 14 itself, or -- I'm a little confused as to exactly --

MEMBER ARMIJO: I thought John's issue was really, it was a big impact on the new plants, not necessarily --

MEMBER STETKAR: It's a big numerical impact --

MEMBER ARMIJO: -- on the existing plants, but operating plants.

MEMBER STETKAR: Philosophically, my

concern is putting in a number. You know, I don't care whether it's 14 days or 37 days or two days.

MR. COLLINS: But that goes across the board.

MEMBER STETKAR: That goes across the board. That's a philosophical. If I back -- if I step back from the philosophy, to the practical implication, certainly, for new plants, that could be a large numerical contribution to core damage frequency, that we are just blanket accepting, by that number.

For existing plants, it's between the minimal and very small, and then you come back to the justifications, what's the basis for that 14 days, that there is also, kind of a bit of a concern about the number for existing plants, because if the agency will accept carte blanche, anything that's less than minimal, a 72 hour number would give you minimal.

MEMBER ARMIJO: Numerically.

MEMBER STETKAR: Numerically, yes, right. A 72 hour would give you one to the minus seven, assuming that --

MEMBER CORRADINI: But the way they apply it, though, so, my only argument back to you there is, the way -- so, I guess I'd buy your argument to remove

a number, because if you went down to minimal, this way they apply it is more restrictive than they do in current plant -- in the current licensing approach.

So, to me, that's almost too restrictive, because the way they've applied the 72 hours would be accumulative any one of the plant configurations.

So, I'd rather have no number and make them justify the number that's appropriate for their plant, then to pick a smaller number.

MEMBER STETKAR: That's one philosophy, but the industry would like some guidance. You know, I'm sensitive to the fact that the industry would like some guidance, and you know, the notion that you put in a -- you know, a value of zero, obviously, is not appropriate.

A value that is perhaps, difficult, but not impossible to meet in practice, and that forces someone to do an analysis for their plant, to justify a longer value, might be okay, with some basis on -- you know, the reason we picked 72 is it's consistent with minimal, and if you want something more than that, you know, do the analysis.

CHAIRMAN SHACK: But again, that's minimal, in terms of the guidance you have for permanent changes in the licensing basis, you get a different

answer if you look for separate changes.

MEMBER STETKAR: Well, but I mean, this essentially is a permanent change in the license, something wired into the tech spec's.

CHAIRMAN SHACK: But you're not going to take the 14 days every 12 months. You know, I could assume that could vary, you know, all over the map.

MEMBER CORRADINI: So, I have a question. May I have a question?

CHAIRMAN SHACK: You know, it's an upper bound on it, but --

MEMBER CORRADINI: A clarification question?

CHAIRMAN SHACK: Well, I can see, that's going to be a discussion point.

MEMBER CORRADINI: A clarification for the staff, because you said something, maybe it shouldn't be in the presentation, but you said you're going to meet at the end of September with whom, about this, and -- I noted that you said you're going to meet with industry reps. I didn't understand.

Somewhere in your presentation, when you were talking to us, you indicated you were going to go back and speak with industry folks about --

MEMBER STETKAR: September 30th.

MEMBER CORRADINI: September 30th, and what's going to happen at that time?

MEMBER STETKAR: There is a public meeting.

MR. DUDLEY: Well, we had a public meeting. There is nothing on my slide that said September 30th.

MEMBER CORRADINI: Well, somebody said something. I noted that you were going to do something before the October meeting, and I thought -- maybe I --

(Off the record comments.)

MR. DUDLEY: Rob is going to have a public meeting on his Reg Guide, right, and that is September 30th.

MR. COLLINS: Yes, Rob is having a public meeting on the study guides, and that's September 30th.

MEMBER CORRADINI: Okay, all right, okay, and then I thought -- okay, so, my question goes to that.

In that discussion, didn't we ask you who is volunteering, at this point, other than warm fuzzies of the industry saying, "Yes, maybe, maybe," nobody is coming up, so, one might ask, since some of the public might ask, so, what's the point of this, if nobody is going to volunteer to do it?

Is this just an option that will never be exercised?

MEMBER ARMIJO: We don't know.

MR. COLLINS: The Commission, you know, the industry officially says, they all want this rule.

MEMBER CORRADINI: Officially?

MR. COLLINS: Yes, I mean, the comments letters came in, they all said, "We support this rule," I mean, NEI was in here, talking about GSI-191 the other day, and they said, "We certainly support, you know, 50.46a," we don't know if this necessarily helps this here, but you know.

MEMBER CORRADINI: Okay, because the reason I asked it is because I thought we asked Rob, and his answer back was, "Until I see a volunteer, I don't sense there is real," --

MR. COLLINS: I understand that, but officially, on paper, everything we get from any licensee, any comment we received from any industry organization, or any licensee has said, we're in support of this rule.

We have problems with different aspects of the rule, it being burdensome, but we're all in favor of going forward with this rule.

Now, if none of them decide to adopt it,

I mean, we can't know that.

MEMBER ARMIJO: Anything that's voluntary, I mean, it's their option, so, why would they oppose --

MR. COLLINS: It's a business decision for them, right.

MEMBER ARMIJO: Why would they oppose it?

MR. COLLINS: Right, sure.

MEMBER CORRADINI: I guess, that's the only reason I'm asking that is, that's why I have -- personally, I have no problem killing it for new plants, because I don't think it will be voluntarily adopted, but I wanted to understand, is there real demand from current plants, that's what I'm asking?

MR. COLLINS: You know, South Texas was the only ones that have -- that have given us a feeling that they're going to pick it up.

MEMBER CORRADINI: Okay.

MR. COLLINS: That's the only one, and they haven't told us they're going to do it either, but I mean, they're the mostly likely candidate.

MR. DINSMORE: Could I just make a couple of comments on this 14 days?

You know, if you think 14 days is giving them too much risk increase, if you take it out,

they're going to come in and say, "Well, tech spec 4B and such and such is increased to 10 to the minus five," and once I get over 10 to the minus five, all that means is I have to put some type of corrective action program that kind of, would make me not exceed that limit so often in the future.

They're going to -- you're not going to get 14 days. You're going to get 30 days, 60 days, back-stops.

MEMBER CORRADINI: Your point being that unless you draw the line somewhere, people are going to try to push it even more than what we would suspect, is that it?

MR. DINSMORE: Oh, yes, they'll come in and --

MEMBER STETKAR: Yes, well, they could do that, under this, right?

MEMBER CORRADINI: I don't think so, not if it says 14 days in the rule.

MR. DINSMORE: They could try, but they could try.

MR. DUDLEY: I realize they're not in the ballpark, I mean --

MR. DINSMORE: We could also say no, but you can have 14, whereas, if the 14 isn't in there,

and they come in and request 60 --

MEMBER STETKAR: Yes, but suppose, Steve, you put 20 -- you know, put in something ludicrous, six hours, all right --

MR. DINSMORE: Well, you know, but that's kind of --

MEMBER STETKAR: But then everybody will come in and try, and they're going to try, instead of -- they're not going to try to say, "I want 14 days," they're going to say, "Well, as long as I have to try, I'm going to try to go for, you know, six months," I mean, if I'm going to do the analysis, to try to relax something that's in there --

MEMBER CORRADINI: Putting his argument back to you would be, now, you're creating burden on the staff, to look at, instead of four cases, 40 cases, I mean, that's what I expect you're going to say back to them.

MR. DINSMORE: Well, I guess I wasn't quite sure what he was -- you're saying put in six hours --

MEMBER CORRADINI: No, no, he's saying putting in something small.

MEMBER STETKAR: If you put in something smaller, you're effectively --

MR. DINSMORE: Yes, nobody will -- then

you're probably right, it's not useable to them, so, they won't be able to use it, so then everybody will try this other stuff.

Whereas, 14 days might be sufficient for them to actually -- I mean, it was also selected as being enough time, that they might be able to actually use it.

MR. COLLINS: Right, they indicated -- I mean, the industry argued with us that they needed something like seven to 14 days, to typically solve most problems that they could have.

It's a consideration. I mean, because when -- we weren't -- we started with zero.

MR. DUDLEY: They even talked about online maintenance, you know, and taking equipment out for that purpose.

MR. COLLINS: I mean, we need to have something which represents the back-stop, because I mean, the Commission requirement is that they mitigate, right, not just that they meet the delta risk, right, it was that they mitigate this event.

So, you know, but there's got to be a back-stop somewhere. They don't have that capability to mitigate.

MR. DUDLEY: So, Bill, I would do the

overview, and maybe truncate, a shortened version of the history and then, just go through the overview. But I'm not sure what -- with respect to the 14 days, you would like from the staff, to present.

PARTICIPANT: I think you should defense it.

MR. DUDLEY: Okay, all right.

MEMBER STETKAR: Yes, I mean, I think if there's anything that you could --

MR. DUDLEY: A defense.

MEMBER STETKAR: Yes, a defense, mount a defense.

MR. DUDLEY: Okay.

MEMBER STETKAR: A technical basis, perhaps, a technical basis for that -- you know, why is it 14 and -- I mean, it's clear, it shouldn't be zero, you know. Why is it 14 and not seven and not 72 hours?

Seven, I think, is, you know, just differently arbitrary than 14, but 72 hours, for example, I can do a calculation -- it's differently arbitrary.

But 72 hours, for example, I can tie to your minimal and very small type numbers.

MR. DINSMORE: Which are themselves,

somewhat arbitrary, but --

MEMBER STETKAR: Right, which I think -- but given the fact that they're in there --

CHAIRMAN SHACK: Again, John, we are trying to be risk-informed, not necessarily risk based.

MEMBER STETKAR: As am I, and I would be perfectly happy to entertain an applicant coming in and saying, "I did a risk-informed evaluation and believe that I can justify keeping these things out for 45 days. Here is my analysis."

MR. COLLINS: And we'd say, "Absolutely not." We don't believe that that's guiding -- providing mitigation capability.

MEMBER CORRADINI: Say it again, I'm sorry.

MR. COLLINS: If somebody comes in and said, "You know, we could keep it out for 45 days, 60 days, 100 days, whatever," and the risk numbers are real small, we would not accept that because the Commission has directed that mitigation capability be provided for that event.

MEMBER STETKAR: How do you justify 14 days, then?

MR. COLLINS: We have to put a back-stop somewhere. But part of this is what Steve said before, it's like, we'd like people -- we'd like to

give them a number that they can live with, okay, so, we're not reviewing all these analyses, you know, unnecessarily, right, and at the same time, we want to put a back-stop in there that's not tremendously risk significant, and we don't think -- what is it, something times 10 to the minus 7th, is very risk significant.

MEMBER CORRADINI: Because that shows mitigation -- that essentially shows mitigation above the TBS?

MR. COLLINS: Yes.

MEMBER CORRADINI: Okay.

MEMBER STETKAR: And pragmatically, you know, I might agree with you, for currently operating plants. New reactors, that's a different consideration.

MR. COLLINS: Our focus has been on operating reactors, all along.

MEMBER STETKAR: As I said, pragmatism and philosophy, you know, I try to separate a bit, but philosophy is --

CHAIRMAN SHACK: The letter will be written pragmatically and is a --

MEMBER CORRADINI: Ghee, I wonder who might be the pragmatist.

MR. DUDLEY: You don't want the staff to mention anything about new reactors, then?

MEMBER ARMIJO: It's going to come up. You might as well.

CHAIRMAN SHACK: Yes, I -- you know, if, in your time -- I would put most of it on the indirect. To me, that is the biggest issue that we have, that will be, to me, a major chunk in the rule here, if we come down in one way or another.

The new reactors, as I say, I think we're all in violent agreement that something will change if the risk metrics change, and how you handle that is a different question.

The 14 days, yes, we'll kill that for the new reactors.

(Off the record comments.)

CHAIRMAN SHACK: At least in the initial draft of the letter. How the Committee will come out, I can never predict, of course.

But I think that that's highly questionable for new reactors. You know, there's enough people here and then Harold, I think would go along with that.

So, to me, the big issue is the indirect.

MR. DUDLEY: Right.

CHAIRMAN SHACK: And the 14 days, for currently operating reactors, I think would be the next major issue.

MR. COLLINS: Now, it's interesting, maybe a currently operating reactor would want to come in and propose less than 14 days, so that they don't chew up their cumulative delta risk.

MR. DINSMORE: It doesn't count.

MR. COLLINS: Why wouldn't it count?

MR. DINSMORE: It doesn't count, because it's not a permanent change.

MR. COLLINS: Okay.

MEMBER STETKAR: And they're just simply allowed to do that, you know, it's not -- if the rule allows it, it's an accepted risk. It's a Commission accepted risk.

MR. COLLINS: Yes.

MEMBER STETKAR: Whatever it is.

MR. COLLINS: Yes, right.

MEMBER ARMIJO: Is there any expectation that industry will make a presentation at the full Committee? Have we heard of anything like that, any requests?

CHAIRMAN SHACK: No, no indication. I mean, you can see the --

MEMBER CORRADINI: The audience is overflowing.

MEMBER STETKAR: And make sure you ask for public comments, before we close.

CHAIRMAN SHACK: Okay, public comments?

MEMBER CORRADINI: They're eating chocolate, they're happy.

MEMBER STETKAR: I'm leaving town.

CHAIRMAN SHACK: Okay, then, thank you, gentlemen.

(Whereupon, the above-entitled matter concluded at approximately 3:05 p.m.)

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Draft Final § 50.46a Rule

Risk-Informed ECCS Requirements

Staff Presentation to the Advisory Committee on Reactor Safeguards

Rockville, Maryland
October 7, 2010

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Staff Presentation

- **Background** 5 min.
  Richard Dudley
- **Summary of § 50.46a rule concept** 10 min.
  Richard Dudley
- **Effects of indirect seismic failures** 25 min.
  Robert Tregoning
- **14 day outage time for > TBS mitigation** 20 min.
  Steve Dinsmore
- **Applying § 50.46a to new reactor designs** 20 min.
  Don Dube

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§ 50.46a Rule Background

- Commission SRM (March 2003) directed staff to prepare proposed rule
- Additional Commission direction provided in July 2004 SRM
- Proposed rule published November 2005
- Industry commented that excessive rule burden would prevent implementation
- Two public meetings to discuss public comments and ways to reduce unnecessary burden
- Met with ACRS on draft final rule in Oct./Nov. 2006

§ 50.46a Rule Background

ACRS Nov. 16, 2006 Letter

- Rule to risk-inform § 50.46 should not be issued in its current form
  - Insufficient defense-in-depth for pipe breaks larger than the TBS
  - Concerns with risk-informed assessment process
  - Concerns with plant specific applicability of expert elicitation and seismic analysis

§ 50.46a Rule Background

Response to ACRS Letter

- Staff requested additional Commission guidance
- Commission SRM - August 2007
  - increase overall defense-in-depth for breaks >TBS
- After staff completed revisions to rule, OGC determined re-notice is necessary
- May 2009 – Staff briefed ACRS on changes made in supplemental proposed rule

§ 50.46a Rule Background

- Supplemental proposed rule published Aug. 2009
- Public comment period ended Jan. 2010
- Staff evaluated public comments and prepared draft final rule language
- Public meeting held on June 4, 2010
- Draft final rule *Federal Register* notice provided to ACRS August 30
- ACRS subcommittee meeting – Sept. 22

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§ 50.46a Final Rule

Subcommittee Meeting Issues:

- Evaluation of seismically-induced indirect piping failures
  …….Rob Tregoning
- 14 day outage time for > TBS mitigation
  …….. Steve Dinsmore
- Risk acceptance criteria for new reactors
  ……. Don Dube

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§ 50.46a Rule Path Forward

Completion Schedule:

- ACRS full committee meeting ..... October 7, 2010
- Provide final rule package to EDO ..... November 29, 2010
- Provide final rule to Commission ..... December 13, 2010

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Summary of § 50.46a Rule Concept

§ 50.46a Final Rule Concept

- Alternative to existing ECCS req'ts (§ 50.46)
- LOCAs divided into 2 regions based on break frequency – transition break size (TBS)
- Requirements unchanged for 1st region (≤ TBS)
- In 2nd region (> TBS) LOCA mitigation requirements relaxed for lower frequency breaks
- Plant changes "enabled" by new requirements must be evaluated by a risk-informed process

§ 50.46a Final Rule Concept

ECCS Analysis Requirements

- Breaks ≤ TBS
  - No change from current § 50.46
- Breaks > TBS
  - No single failure assumption
  - Credit for offsite power
  - Credit for non-safety equipment
  - Alternative metrics for “coolable geometry” may be used if justified

§ 50.46a Final Rule Concept

- **Transition break size**
  - PWRs – largest attached pipe to the main coolant piping
  - BWRs – largest attached feedwater or residual heat removal line inside containment

§ 50.46a Final Rule Concept

Initial Conversion to § 50.46a

- Demonstrate applicability of elicitation report
- Demonstrate applicability of staff seismic study or provide a plant specific study (direct & indirect failures)
- Evaluation of leak detection capability
- If self-approval process is desired, describe risk informed process for evaluating future changes

§ 50.46a Final Rule Concept

Plant Changes Enabled by § 50.46a

- Proposed in initial application (and later)
- For enabled changes:
  - Re-analyze ECCS for 2 regions using NRC-approved methods
  - For any non-safety equipment that is credited in analysis of breaks >TBS:
    - List equipment in Tech Specs
    - Provide on-site power (manual connection OK)
  - Demonstrate by risk-informed analysis that risk-informed acceptance criteria are met

§ 50.46a Final Rule Concept

Risk-Informed Acceptance Criteria

- For changes submitted for NRC review
  - "very small" cumulative risk increase
- For self-approved changes
  - "minimal" risk increase
  - § 50.59 is satisfied
- For all changes:
  - defense-in-depth
  - safety margins
  - monitoring program
- For certified designs:
  - No significant decrease in level of safety

§ 50.46a Final Rule Concept

Operational Requirements

- All future plant changes (enabled/not) must be reviewed to ensure continued applicability of 2 TBS studies
- Sufficiently sensitive leak detection capability must be maintained for piping larger than TBS
- Operation is limited to short time (≤14 days/12 mo. or NRC approved alt.) if breaks > TBS not shown to meet acceptance criteria
- PRA methods must be of sufficient scope and quality
- Periodically confirm ≤ “very small” cumulative risk increase via PRA update

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Effects of Indirect Seismic Failures

(See slides in separate package)

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Allowable Out-of-Service Time (14 days) for Equipment Credited in LBLOCA Analysis

Stephen Dinsmore 415-8482
ACRS Meeting
October 7, 2010

Probabilistic Risk Analyses

Overview of Requirement History

- Commission direction indicated that the rule:
  - should include requirements for licensees to maintain capability to mitigate the full spectrum of LOCAs
  - capabilities for beyond design-basis events should be controlled by NRC requirements commensurate with the safety significance of these capabilities

- Initial published rule had "no operation in unanalyzed condition" but this has proven to be undesirable (e.g., need to reduce power if LPSI pump becomes unavailable) and not necessarily commensurate with safety significance

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Probabilistic Risk Analyses

Overview of Requirement History (cont.)

- Current Tech Specs and risk-informed operational controls (MRule and TS initiatives) deal with degraded functions, not loss of function.
- TS initiative 6 does deal with loss of function but differs from current controls and not yet fully implemented
- Rule modified to add flexibility and reflect near-term risk-informed method advances
- Current proposed rule provides:
  - a fixed time (to provide a fully vetted acceptable alternative) or
  - an alternative proposed by the licensee and approved by the staff (to provide flexibility)

Probabilistic Risk Analyses

Development of 14 days/year

- RG 1.177, “An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications “
  - Acceptance guideline integral conditional core damage probability $\leq 5 \times 10^{-7}$ integral conditional large early release frequency $\leq 5 \times 10^{-8}$
  - Assume LOCA leads to core damage (and large LOCA, low pressure core damage places little stress on containment)
  - Use LOCA frequency of 10^{-5}/year frequency with no mitigation
  - Yields allowed AOT of 18 days

- SRP Chapter 2.2.1 and 2.2.2 identifying external events that need to be design basis events (that need to be mitigated)
  - External events with a frequency $< 10^{-7}$/year need not be design basis events
  - Assume LOCA leads to core damage (and large LOCA, low pressure core damage places little stress on containment)
  - Use LOCA frequency of 10^{-5}/year with no mitigation
  - Yields allowed outage time of 3.6 days

- 14 days is
  - In between 4 days and 18 days
  - A “fairly long” AOT that industry indicated that it would normally be sufficient

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Probabilistic Risk Analyses

PWR Risk-informed intervals

- Assuming LOCA frequency of 10^{-5}/year leads to core damage frequency from full utilization of this 14 days of 3.8×10^{-7}/year
- Assume LOCA arithmetic mean frequency of 5×10^{-6}/year reduces risk (increases AOT) by factor of 2
- Assume LOCA geometric mean frequency of 10^{-6}/year reduces risk (increase AOT) by factor of 10
- If unanalyzed condition LOCA > TBS (12 inches), may be possible to use frequency of larger breaks

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Application of Risk Acceptance Criteria to New Reactors

Don Dube
NRO/DSRA

Subcommittee Concerns

Application of Risk Acceptance Criteria to New Reactors

- August 10, 2009 FRN:
  - Staff in early stages of addressing “risk metrics” for new reactors
  - NRC requested comments on:
    - Use of large release frequency (LRF) vs. LERF
    - “Very small” and “minimal” one decade lower for new reactors
- Discussions on “modifying risk-informed regulatory guidance” for new reactors ongoing
- Awaiting Commission decision on SECY-10-0121

Subcommittee Concerns

New Reactors (cont.)

- Staff agrees with external stakeholder comments that it is premature to address risk metrics of CDF and LRF/LERF pending Commission direction on SECY-10-0121
- The following was added to SOC and rule to be consistent with Option 2 of SECY-10-0121: "Applicants referencing a certified design may need to supplement these criteria to also meet the requirement that implementing the proposed changes will not result in a significant decrease in the level of safety otherwise provided by the certified design."

Subcommittee Concerns

New Reactors (cont.)

- If, as a result of Commission direction, different guidance is promulgated that describes new metrics to be used for new reactors, appropriate changes will be made to § 50.46a.

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Seismically Induced Indirect Piping Failures in 10 CFR 50.46a and DG-1216

Rob Tregoning
Nuclear Regulatory Commission

Advisory Committee for Reactor Safeguards Meeting
Rockville, Maryland
October 7, 2010

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Presentation Objectives

- Technical basis associated with treatment of seismically induced indirect failures
- Existing requirements and guidance associated with seismically induced indirect failures
- Feedback received from ACRS Subcommittee on Regulatory Policies and Practices (9/22)
- Staff's response to feedback and proposed path forward

Indirect Piping Failures: Background

- Failure of a structure, support, or component (SSC) due to a seismic event which subsequently causes the failure of a reactor coolant system (RCS) pipe primary pressure boundary piping component
  - RCS piping system support failures
  - Excessive deformation or failure of in-line components (e.g., valves)
  - Failure of major components or their supports acting as anchor points
  - Failure of non-attached SSC which impacts the RCS piping

- Only RCS failures greater than TBS are a consideration for 10 CFR 50.46a
  - Smaller breaks regulated by existing 10 CFR 50.46 requirements
  - Ensure that these failure do not invalidate the technical basis supporting the transition break size (TBS) development

Indirect Piping Failures: Prior Study

- Lawrence Livermore Study (NUREG/CRs – 3660, 3663, 4290, 4792) findings and recommendations
  - Seismically induced support failure is the most likely cause of indirectly induced double-ended guillotine breaks
  - Strength of component supports, currently designed for the combination of SSE and DEGB loads, should not be reduced
- NUREG-1903 review of seismic PRAs, seismic safety margin research program, and IPEEE submittals confirmed LLNL recommendations
  - Valves, non-degraded piping, and pipe supports have a significantly higher capacity than other RCS components
  - Other RCS components
    - These components, especially component supports, are more vulnerable than the piping and pipe supports.
    - Most significant NSSS failure modes are attributable to failures of major components or their supports.

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Indirect Piping Failures: Updated Estimates

- Subsequent efforts have used the original LLNL approach, updated for more recent understanding of plant-specific factors
- NUREG-1903
  - Analyzed large component support failures that may lead to piping failure (i.e., indirect piping failure) associated with rare seismic events
  - Two cases: Westinghouse rock site, CE soil site
  - Used NUREG-1488 hazard curves (1994)
  - Results: mean piping failure probability for both cases $\approx 10^{-6}$/yr
- EPRI
  - Three cases: Westinghouse rock site, CE rock site, and GE soil site
  - Used updated seismic hazard curves developed for early site permits
  - Results: mean piping failure probabilities from 6×10^{-6}/yr - 10^{-8}/yr

Indirect Piping Failures: Existing Requirements

- Federal Register Notice (Vol. 74, No. 152, 8/10/09) for 10 CFR 50.46a
  - No requirements to demonstrate that the frequency of indirect failures greater than the TBS is acceptable
  - No generic changes allowed to seismic design, testing, analysis, qualification, and maintenance requirements (i.e., seismic design basis)
  - Justify any proposed changes by plant-specific analysis
- DG-1216, "Plant-specific applicability of Transition Break Size Specified in 10 CFR 50.46a" contains no guidance to demonstrate acceptable indirect failure frequencies
- Original basis for staff position
  - No basis for allowing generic changes in rule
    - NUREG-1903 evaluated one failure mode for two plants
    - EPRI considered the effect of updated seismicity estimates on three plants
  - Frequency of failures would remain less than TBS frequency (i.e., $< 10^{-5}$/yr) because original design basis retained

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Indirect Piping Failures: ACRS Feedback

- Relaxation of mitigation requirements for breaks beyond the TBS could result in an unacceptable risk due to indirect failures, even if the frequency of these failures does not change
  - Possibility that indirect seismic failure frequency may be equal to or greater than direct seismic failure frequency
  - Limited studies show that highest frequency estimation approaches the frequency used to select the TBS (i.e., 10^{-5}/yr)

- Licensee should have to demonstrate that the frequency associated with seismically induced indirect RCS piping failures is acceptable
  - Consistent with treatment of seismically induced direct failures
  - Ensures that indirect failures are not a significant risk contributor

Indirect Piping Failures: Staff Response and Path Forward

- Staff agrees with ACRS feedback that indirect failures should be demonstrated to be insignificant risk contributors
  - Updated seismic hazard information (GI-199)
  - Smaller allowable risk increase in draft final rule (i.e., changed from “small” to “very small”)
- Path forward
  - Modified the FRN/rule language for the draft final rule
  - Add guidance in DG-1216 for seismically induced indirect piping failures
    - Initial ideas and concepts discussed during recent public meeting
    - Use pilot plant study to evaluate the acceptability of the planned guidance
  - Request that ACRS document recommendations in letter to Commission
    - Require 10 CFR 50.46a applicants to demonstrate that the frequency associated with seismically induced indirect RCS piping failures is acceptable
    - Request that staff provide guidance for conducting these demonstrations