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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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MEETING OF THE SUBCOMMITTEE ON RELIABILITY AND

PROBABILISTIC RISK ASSESSMENT

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FRIDAY,

MARCH 23, 2007

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The Subcommittee convened at 8:30 a.m. in Room T-2B3 of the Headquarters of the Nuclear Regulatory Commission, 11545 Rockville Pike, Rockville, Maryland, George E. Apostolakis, Chairman, presiding.

MEMBERS PRESENT:

GEORGE E. APOSTOLAKIS, Chairman

SAID ABDEL-KHALIK

MARIO V. BONACA

THOMAS S. KRESS

OTTO L. MAYNARD

WILLIAM J. SHACK

STAFF PRESENT:

MAITRI BANERJEE

A-G-EN-D-A

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

8:25 a.m.

CHAIRMAN APOSTOLAKIS: The meeting will now come to order. This is a meeting of the Reliability and Probability Risk Assessment Subcommittee of the ACRS.

I am George Apostolakis, Chairman of the Subcommittee.

ACRS Members in attendance are Dr. Said Abdel-Khalik, William Shack, Tom Kress, Otto Maynard and Mario Bonaca.

The purpose of this meeting is to review the industry guidance document on the safety evaluation prepared by the NRC Staff on the risk managed technical specifications 4B. We will hear presentations from representative of the Office of Nuclear Reactor Regulation and Nuclear Energy Institute and the Electric Power Research Institute.

RMTS Initiative 4B proposed to rely on probability risk assessment and risk monitors to calculate technical specification completion time for returning structures, systems and components to operable steps.

The Subcommittee will gather information, analyze relevant issues and facts and formulate

proposed position and action as appropriate for deliberation by the full Committee.

The rules for participation in today's meeting were announced as part of the notice of this meeting previously published in the *Federal Register* on March 5, 2007. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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 the microphones located throughout the meeting room when addressing the Subcommittee. Participants should first identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

The ACRS Subcommittees on Reliability and PRA and on Plant Operations were jointly briefed on April 28, 2006 by the NRC and the industry on the status of this initiative. And, of course, at that time we provided comments and raised some questions. And the Staff indicated at the time that the guidance document was not complete and pilot plant visits were scheduled to review the on site programs during the summer months of last year before preparing a safety

evaluation report.

We requested that the Staff brief us again after completing their safety evaluation report. And that's why we're here today. And the staff will brief us, the subcommittee today. And we have scheduled time for the full Committee to be briefed at the next meeting at the beginning of April. And the staff is asking a letter from the ACRS. Of course, they would prefer it to say that the Committee agrees with the Staff's endorsement of the RMTS guidelines.

So we will now proceed with the meeting. And I call upon Mr. Tjader of the Office of Nuclear Reactor Regulation to begin.

Bob?

MR. TJADER: Thank you, Dr. Apostolakis, ACRS Members.

Today we're reporting once again on this management tech spec initiative for the risk-informed completion times.

Today we will discuss the risk management tech spec guidance document, NEI 06-09 which you have received in final form. That document contains the process for determining risk-informed completion times, the requirements, the limits and overall guidance for implementing risk-informed completion

times.

The document has been developed, negotiated and evolved over many years. The Staff believes that this document is acceptable for implementing risk-informed completion times and that it enhances safety and is an improvement in operating with technical specifications.

The Staff's acceptance is reflected in the near complete safety evaluation that has been provided to you. Once any comments from industry and the ACRS are received, if any, and once they're addressed and incorporated a final safety evaluation will be developed and be provided to the full ACRS prior to the full ACRS Committee meeting in April.

That safety evaluation, final safety evaluation will reflect some differences from the version that you have, but nothing of significance in way of technical application or implementation of it. There are some editorial changes, some consistency changes to be consistent with operability determination process and there is some discussion of the degree to which examples should be included in the document. And we're working out those final details, but the essence of the safety evaluation provided to you is in its final form.

In addition to the guidance document which I Andrew Howe, the lead reviewer from the PRA Branch will discuss, we'll also provide you some related information which you requested at prior meetings such as human reliability, uncertainty and a discussion of the audit which Andrew Howe will provide you.

And as you mentioned, Dr. Apostolakis, we do seek the Commission's support for this with this initiative in validating the effort.

Next slide.

The purpose of the risk management tech specs initiatives and this initiative 4B as we call our support completion time are to be consistent with the Commission's policies to utilize risk information and decision making both in changes to tech specs and in implementing, such as this one, the technical specifications using risk information to do the correct and safe thing. To take the correct action.

The initiatives are consistent with -- this initiative and others are consistent with the maintenance rule and established guidance such as Reg. Guide 1.174 and 1.177 and NUMARC guidance that we utilize and, to some degree, have endorsed.

CHAIRMAN APOSTOLAKIS: Now Reg. Guide 1.174 refers to permanent changes.

MR. TJADER: Correct. 1.174 is the overall application of risk of applying risk in decision making processes. 1.177 is the specific application of technical specifications.

CHAIRMAN APOSTOLAKIS: But the main idea behind 1.174 was really the permanent changes. And you do make a connection with it even though the changes are temporary. And I'd like at some point to have a discussion on that one. We don't have to do it now. At the appropriate time. But you state that periodically that we'll have to calculate the increase in risk and go back to 1.174. I think that's an interesting comment.

But 1.177 is the main one that really drives this?

MR. TJADER: The specific application of utilizing risk --

CHAIRMAN APOSTOLAKIS: Right.

MR. TJADER: -- in technical specifications. And to some degree you're right. They're dealing with AOT and 3.C changes that to some extent are permanent. But these decisions are consistent with that and are not in anyway superseding or overruling those guidance documents.

MR. HOWE: That is the main. 1.177 is the

tech spec change that's permanent.

MR. TJADER: 1.177.

MR. HOWE: 1.777, right. This is now a floating kind of change.

MR. TJADER: An extension of that. An extension.

CHAIRMAN APOSTOLAKIS: Right. But it's 1.177 that really deals with incremental quantities as opposed to 1.174.

By the way, is the fire document that we have received included in all of this.

MR. HOWE: I'm not familiar with our document.

MR. TJADER: It's the EPRI fire document--

CHAIRMAN APOSTOLAKIS: It's not? You have not reviewed this? It's not part of your review --

MR. HOWE: We have not reviewed the EPRI fire methodologies.

CHAIRMAN APOSTOLAKIS: Okay.

MR. TJADER: It is an example of methodology that would be utilized for applying it to a PRA.

CHAIRMAN APOSTOLAKIS: But that will be reviewed at some future time?

MR. TJADER: Well, I mean PRA Reg. Guide.

1.200 does not yet incorporate fire in it. At some extent it will, and then that will be an actual review of PRAs in the application of 4B. What we do now, and what we have done last summer with South Texas is we've gone to them and the PRA staff has reviewed that PRA and they extensively reviewed how fire is reflected in the PRA. And, in fact, your report deals with that for several paragraphs.

And so until Reg. Guide 1.200 is in place and its application is incorporated we will review the incorporation of fire in the PRA --

CHAIRMAN APOSTOLAKIS: So one major criterion or -- I don't know, in this case is that unless the PRA has been developed according to 1.200, you're not looking --

MR. TJADER: I'm sorry.

MR. HOWE: Let me --

CHAIRMAN APOSTOLAKIS: The fire is not part of 1.200?

MR. HOWE: That's right. Today Reg. Guide 1.200 only addresses internal events.

CHAIRMAN APOSTOLAKIS: Right.

MR. HOWE: It has some high level requirements for fire, but no standard has been enforced. Our position is that until those standards

are in place, we will have to: First of all, license these must quantitatively addressed fires and afford the application, and the Staff has to review how they are doing that. If they have a fire PRA, we'll have to do a fairly extensive review of how it was developed, how screen criteria was applied, et cetera. If they use bounding analyses or other more conservative, we'll have to review those to see that they are appropriate for a 4B application. But once Reg. Guide 1.200 is revised to endorse the standard and whatever grace has expired, licensees will be expected if they're implementing 4B to have a fire PRA to address the significant risk --

CHAIRMAN APOSTOLAKIS: Well, there is an EPRI document we received titled "Methodology For Fire Configuration Risk Management."

MR. HOWE: Right.

CHAIRMAN APOSTOLAKIS: This is not part of what you have reviewed?

MR. HOWE: We have not reviewed that and we have not endorsed that. In fact, our SE specifically states that that we have not endorsed that. That is not to say that a licensee couldn't come forward and say we would like to use this in 4B, and then we would review it. But at this point we

haven't.

MR. TJADER: And as I said before, the underlying purpose of these initiatives in Initiative 4B is to enhance safety, enhance the operator focus on safety to ensure that the appropriate safe action is taken and that knee-jerk actions such as shutdown are not necessarily taken.

Next slide.

Just going very briefly over risk-informed completion times it is, as you stated, a real-time determination or calculation of a completion time based upon the plant configuration and its associated risk. It extends the existing completion time.

If a licensee within the existing completing time of the tech specs determines that they may not be able to restore the condition to operable status within the existing completion time, within that completion time they will perform a risk assessment to determine what would be an appropriate risk-informed completion time up to a maximum backstop of 30 days.

The guidance document includes the decision making process. It includes requirements, guidance, requirements for PRA, technical adequacy, configuration risk monitoring tool, requirements,

documenting requirement, training requirements.

South Texas is the pilot plant that is your approval. The PRA audit was completed last summer, you have the report. We expect to issue their license amendment this summer, Fort Calhoun later in the year.

Next slide.

The risk-informed completion time benefits are that they take into account integrated configuration risks. It does take into account when you're in a risk-informed completion time multiple component outages both tech spec and non-tech spec systems that are reflected in the PRA.

It allows for decision making on a real-time basis with risk insights, utilizing risk insights.

Next slide.

The risk management guidance document NEI 06-09, the methodology document will be incorporated into the administrative controls section of the tech specs under the configuration risk management program. So the requirements and limits within this document will become tech spec requirements and limits.

The organization. Section 2 has the absolute requirements and limits within it. Section

3 has the overall guidance and an explanation of those limits. 4 deals with PRA. And there are other sections on documentation and training incorporated within.

Next slide.

This is a good example of how it will work, the completion time can confirm completion time, the risk-based or risk-informed completion time up to a maximum of 30 days.

Next slide.

Just a generic tech spec example, which is in the guidance document as an example. You would have a system that is inoperable. You're going to have to restore it within 72 hours. Of the licensee determines that they can't restore it within 72 hours, they must do the qualified risk assessment as prescribed by the guidance document to determine what the appropriate risk-informed completion time is. That must be done within the 72 hours.

CHAIRMAN APOSTOLAKIS: Wait a minute. The 72 hours is the frontstop?

MR. TJADER: That's true. That's the frontstop. That's existing. That's just --

CHAIRMAN APOSTOLAKIS: That comes from 1.177?

MR. TJADER: No, no.

MR. HOWE: No, the PRA. But it's most probably the deterministically derived completion that exists --

CHAIRMAN APOSTOLAKIS: Oh, it is. Yes.

MR. HOWE: There's nothing -- with 72 hours. It could be whatever it is in the specs. It could be 4 hours, it could be 7 days. It's whatever it's.

CHAIRMAN APOSTOLAKIS: It's the frontstop.

MR. TJADER: It's the frontstop. Whatever that frontstop is if the licensee determines that they need to go beyond that to restore the system, they perform a quantified risk assessment within the frontstop and determine what the appropriate risk-informed completion time. Then they have to periodically reperform that when there are configuration changes, emergent conditions, SSCs become inoperable, SCCs are restored it will be updated.

MEMBER SHACK: Has anybody actually used 1.177 to change their tech specs?

MR. TJADER: Extensively. They've come in frequently to extend their existing -- and surveillance frequencies. Yes.

CHAIRMAN APOSTOLAKIS: Right. I believe their diesel generator AOT at South Texas is now 7 days or 14?

MEMBER MAYNARD: Fourteen days.

CHAIRMAN APOSTOLAKIS: Fourteen?

MR. TJADER: Fourteen.

MEMBER ABDEL-KHALIK: Has there been any situation in which the opposite was found to be true where the frontstop has been found to be inadequate?

MR. TJADER: I'm not aware of any. The frontstops were originally deterministically derived by the engineers that designed and developed the plant. And they were very conservatively derived. And they were also, keep in mind, focused just on that system and the inoperability of that system. So the numbers are very conservative in nature. And if in the application, of course, of Initiative 4B it is found that a frontstop is not conservative, it would follow whatever completion time you derive from risk-informed completion time when you're in there and then it would be incumbent upon the licensee, it would be the prudent thing to do, the appropriate thing to do to come in with a license amendment request make it conservative and appropriate. But I don't think we've found a frontstop that's not conservative.

Now keep in mind it is with respect to just that one system not multiple inoperabilities when you could then encounter a situation where perhaps the risk-informed completion time could be less than some of the frontstops.

CHAIRMAN APOSTOLAKIS: What does IAW stand for?

MR. TJADER: In accordance with.

CHAIRMAN APOSTOLAKIS: In accordance with?

MR. TJADER: Yes.

MEMBER BONACA: Now, say that you're having a 30 day calculated completion time and now you're having an emergent condition, as you mentioned before, is there a specific time within which you have to perform an evaluation?

MR. TJADER: Subsequent analyses have to be performed within the shortest of the existing completion times or 12 hours, whichever is shorter.

MEMBER BONACA: Okay. So either 12 hours or the 72 hours?

MR. TJADER: No, no. The 72 is just an example of an example of an existing frontstop.

MEMBER BONACA: I understand.

MR. TJADER: The guidance document says that completion time have to be calculated within the

existing frontstop completion times.

MEMBER BONACA: Okay.

MR. TJADER: Whatever they are; 7 hours, 4 hours or 12 hours whichever is shorter.

MEMBER BONACA: Whichever is shorter? Okay.

CHAIRMAN APOSTOLAKIS: Where did the 12 hours come from?

MR. TJADER: I'm sorry?

CHAIRMAN APOSTOLAKIS: Where did the 12 hours come from?

MR. TJADER: Well, a couple of years ago you probably don't remember the slide up there said 24 hours and there was a lot of discussion whether that was too long of a time. And we discussed it and we thought that 12 hours was a time in which -- in reality, 12 hours for the operator is plenty of time to chug and plug the numbers in his configuration risk management tool. What the 12 hours does is permit administrative processes within the plant to proceed in order -- in case they come into a configuration, for instance in South Texas a case that may not be in the database, that's not yet analyzed, it gives them time to at least to attempt to address that configuration, that 12 hours. Twenty hours instead of

24, we went back to 12 because 12 hours is, for the most part, is -- what do you call it -- a watch cycle.y

CHAIRMAN APOSTOLAKIS: So let me understand. The system is down -- the subsystem is down. The 72 hour limit starts running, right? They have to --

MR. TJADER: The clock starts as soon as you find an inoperability.

CHAIRMAN APOSTOLAKIS: They realize 5 hours into the 72 hours that they cannot complete it by 72 hours. That's when the 12 hour limit starts?

MR. TJADER: No, no, no. If they realize within the 72 hours they can't restore the system, okay?

CHAIRMAN APOSTOLAKIS: Yes.

MR. TJADER: They can then perform a risk-informed completion time analyses within that 72 hours. That can be done anytime in the 72 hours. Then they're going to come up with a risk-informed completion time. And that risk-informed completion time is going to be independent of that 72 hours. That's going to be whatever the configuration of the plant dictates.

CHAIRMAN APOSTOLAKIS: Right.

MR. TJADER: Okay. The clock starts at the inoperability, whatever your completion time is.

CHAIRMAN APOSTOLAKIS: I understand that. So the 12 hours, where is the 12 hours?

MR. TJADER: Well, that is when you have an emergent --

CHAIRMAN APOSTOLAKIS: When you have an emergent condition?

MR. TJADER: You have a new inoperability. I see.

MR. HOWE: The bottom line is this: Until the licensee has calculated a valid risk-informed completion time he has to comply with his existing specs. So when 72 hours is reached, the licensee does not yet have a valid RICT calculated, he beings the shutdown process. At the point in time when he has that valid RICT and he knows he can continue to operate, he could continue to operate.

If an emerging condition emerges while you're in a risk-informed completion time --

MEMBER BONACA: It means an other component?

MR. HOWE: -- maybe you're in a 2 hour LCO or four hour LCO, at the point of time when you reach that limit if you don't have a new valid RICT that

reflects that new emergent condition, you start shutting down. When you have the RICT and it allows you to continue to operate, then you may continue to operate.

MEMBER BONACA: Well the reason why I asked the question was because I was wondering whether 12 hours is an adequate time. And it seems to be a short time. But you said that you feel that it's plenty sufficient?

MR. TJADER: Yes.

CHAIRMAN APOSTOLAKIS: Let's see again. We'll go down. The clock starts. At 60 hours there is an emergent condition. By that time they were estimating they could complete it by the 72 hours. So they only have 12 hours now. Let's make it 65 hours. They only have 7 hours.

Now they can go back to a preexisting configuration with a new situation and say "Oh, now we have a RICT of, you know, 90 hours." If they don't have already -- they have to figure out what to do in the remaining 7 hours?

MR. HOWE: I'll come back to this. Until you have a valid risk-informed completion time you must comply with your existing specs --

CHAIRMAN APOSTOLAKIS: Sot hey can have a

certain amount?

MR. HOWE: If the existing specs during a RICT and the existing specs are allowing you to -- they're not restrictive, you have 12 hours to determine. At the end of 12 hours if you're not sure your RICT is valid, then you follow the existing specs. You're out of the risk-informed, you're back to the existing specs.

MEMBER BONACA: For most --

MR. HOWE: It's a grace period.

MEMBER BONACA: For most significant components it seems to me by reading this that they already have calculated RICT time, right? I mean they already have -- so then they'll have to, you know, in the 72 hours -- I mean, they can see whether or not they can stay within 72 hours or immediately go to their configuration? I mean, it is not --

MR. TJADER: It should not take -- the actual argument said the plugging and chugging of the numbers should not take 12 hours.

MEMBER BONACA: Yes. Yes. Now, the reason I asked about an emerging situation, it means that there is another component. And so now I know that they have calculated -- they have a matrix with probably you have several components that you've

considered already in your matrix. And so they really have also a way to immediately accommodate that?

MR. TJADER: Right.

MEMBER BONACA: I would expect that it is difficult to find multiple components that have not been considered, I mean if they have already several thousand combinations. Okay.

MEMBER MAYNARD: Where's the 12 hours going to be? Will that be in the tech specs or is that pat of the guidance documents. What implies that as the requirement?

MR. TJADER: It is in section 2 of the guidance documents, both in the guidance document will be a requirement in the admin control section of the tech spec in the configuration risk management program maybe that requirements they'd have to follow.

Next slide.

What this is is this is a tabular form of section 3-1. I'll just quickly go through it.

Figure 3-1 in the guidance document gives you a flow chart of the logic that we did.

Basically, it has a tech spec, it's been entered that allows the use of risk-informed completion times. The licensee when he comes in will define specifically which tech specs, Initiative 4B,

risk-informed completion times can comply to. If the answer is no, well you apply the current tech specs and the current tech spec completion time limits.

If it's yes, then the next question is is the frontstop expected to be exceeded,you expect to need to extend that completion time. If it's yes, then you do the calculation. And you do it, the completion time is calculated to an ICDP of 10 to the minus fifth and that gives you the time that you have.

There is a ten to the minus sixth point, which we call a risk management action time. And that time the licensee must consciously evaluate and ascertain what management actions, compensatory actions must be taken for the sake of safety and plant appropriateness.

If you don't expect to go beyond the frontstop, then you do not need to apply 4B.

CHAIRMAN APOSTOLAKIS: You mentioned that a major element in this is Regulatory Guide 1.200.

MR. TJADER: PRA quality.

CHAIRMAN APOSTOLAKIS: But 1-200 refers to PRA quality for standard PRAs. And here it seems to me you're not using the PRA. You have to modify the PRA.

MR. HOWE: We'll be talking more about

that one later.

CHAIRMAN APOSTOLAKIS: Later?

MR. HOWE: Yes, sir.

CHAIRMAN APOSTOLAKIS: Okay.

MR. HOWE: We know that's an issue you wanted to hear about.

MR. TJADER: If any of the completion time limits have been reached, if you're within the frontstop and your reach completion time, if you're in the risk-informed completion time, you reach the completion time limit or the backstop completion time has been reached, whichever is applicable, then you take the appropriate subsequent tech spec action. In other words, you haven't been able to comply with that action you're within, you take the subsequent one, which is in all likelihood get out of the mode of applicability, shutdown.

And then have the actions been existed? If you're in a risk-informed completion time and you have to come out of it, then you apply the subsequent tech spec required requirements shutting down. If you haven't existed, you're still within a completion time, then you continue to apply risk management actions, updating, recalculating risk-informed completion time depending on emergent conditions.

Next slide. Basically the limits that the risk-informed completion time is calculated to, the risk management actions are calculated to an ICDP of one to the minus six or ten to the minus seven. Either the -- or ten to the minus fifth ICDP or ten to the minus six ILERP and any instantaneous core damage frequency of the ten to the minus third and ten to the fourth LERF puts you into immediate out of the completion time into the required actions.

CHAIRMAN APOSTOLAKIS: The NRC, though, you state does not endorse whatever. You take no position in the ten to the minus three?

MR. TJADER: Oh, yes, we do.

CHAIRMAN APOSTOLAKIS: Don't you say somewhere that this is --

MR. TJADER: We take no position on the ten to the third or ten to the minus fourth -=-

CHAIRMAN APOSTOLAKIS: Yes.

MR. TJADER: --instantaneous limits.

CHAIRMAN APOSTOLAKIS: Yes.

MR. TJADER: There are voluntary restrictions on this program by industry, but the Office of NRR has not stated that that's the acceptable limit or that we may not come up with limits ourselves sometimes.

CHAIRMAN APOSTOLAKIS: That's what I'm saying.

MR. TJADER: But in the meantime they do--

CHAIRMAN APOSTOLAKIS: This is not part of your approval?

MR. TJADER: The ten to the minus fifth and ten to the minus sixth numbers are.

CHAIRMAN APOSTOLAKIS: Yes, I know.

MR. TJADER: Not the --

CHAIRMAN APOSTOLAKIS: Right.

MR. TJADER: I'm walking this fine line here as previous safety evaluations said about the instantaneous risk on this. They were proposed at NUMARC 93-01.

CHAIRMAN APOSTOLAKIS: I know.

MR. TJADER: The Staff said we accept them but we don't endorse them. I'm saying the same thing.

CHAIRMAN APOSTOLAKIS: And they're accepted. And you're saying if you want to do it, do it, but we have no position.

MR. TJADER: In our guidance -- the guidance -- as a review in NRR is in Reg. Guide.1.177, 1.174 as well as what's been endorsed in NUMARC 93-01 for configuration -- I'm applying that to this program to reach acceptability. Okay. These aren't part of my

reg guidance.

CHAIRMAN APOSTOLAKIS: What I'm saying is that this slide should say we approve everything and except that we take no position on relying not to exceed ten to the three and ten to the minus five.

MR. TJADER: Yes, if they find that acceptable.

CHAIRMAN APOSTOLAKIS: If they don't object.

MEMBER MAYNARD: For this application for this process you're accepting that that's going to be a limit. But you're not relying --

CHAIRMAN APOSTOLAKIS: Even if it is exceeded, you are not going to action because it's not--

MR. TJADER: In parts of Initiative 4B and when a licensee comes in and adopts this program and we approve it, they will have this guidance document incorporated in their tech specs. This guidance document in section 2 sets certain limits and thresholds. One of those thresholds is if you got a CDF, ten to the minus three, LERF ten to the minus four, no voluntary action and -- what it may not have here -- but also it says is not only is there no voluntary action, basically what it is says is that if

in a configuration due to an emergent event, implement the appropriate risk management actions.

CHAIRMAN APOSTOLAKIS: Who says that?

MR. TJADER: That's in the guidance document which they will --

CHAIRMAN APOSTOLAKIS: But you say in the SER the Staff neither endorses nor disapproves of the ten to the minus three and the ten to the minus four values. That's a very statement.

MR. HOWE: Exactly what was said about the original guidance and I took those same words, the endorsement.

CHAIRMAN APOSTOLAKIS: And this is also the current guidance?

MR. HOWE: Right. My management basically said to me you can't use that as an acceptance basis for this because that's not --

CHAIRMAN APOSTOLAKIS: Exactly. So why are we making a big deal out of it? It's very clear. You neither endorse nor disapprove? In other words, they cannot come to you with an argument that's based on ten to the minus three unless you want to review the argument and Staff, you know, okay. That's very simple.

MR. HOWE: But I'll point this out. If

they reach that and they say well even though the guidance document says I shouldn't do that, I'm going to because the NRC hasn't said that. No, they were committing to that guidance document, and we accept that. That's fine.

MS. BANERJEE: And we can write violations, right?

MR. HOWE: Yes. It's part of the document, hopefully. It's a tech spec limit.

MS. BANERJEE: Well, it becomes part of tech spec.

MR. TJADER: A tech spec limit.

MR. HARRISON: Yes. This is Donnie Harrison from the PRA Branch.

What's happening here is the industry is voluntarily opining this to themselves, if you look at it that way. So i'm agreeing with your, Dr. Apostolakis. It is --

CHAIRMAN APOSTOLAKIS: Is it part of the tech spec?

MR. HARRISON: It becomes part of the tech specs because it's endorsed in the guidance, but not endorsed by us. It's being done by the industry to themselves.

CHAIRMAN APOSTOLAKIS: Well, it's

interesting. We neither endorse nor disapprove, yet it's part of the guidance. Well, that's very interesting.

MR. TJADER: I think we've discussed it adequately. I think quickly just go to 15 and then 16. What they do is they show the documentation requirements that when you go within a risk-informed completion time things that must be documented. And then 16 is some of the training prior to a plant implementing this. We envision what personnel have to be trained.

Let me turn it over to Andrew Howe of the PRA Branch and he will now discuss the PRA aspects of the limits.

MEMBER SHACK: Just one question. Those incremental limits on the ICDP, what other guidance documents are those from? I mean, that's a new position here, isn't it?

MR. TJADER: It's consistent with 1.177. Reg. Guide 1.182 endorsed those limits with the exception of the instantaneous limits from 93-01 in a specific revision. I don't remember exactly. Section 11 and --

MEMBER SHACK: Okay. So 1.177 doesn't?

MR. TJADER: No.

MEMBER SHACK: It has a different set of incremental limits?

MR. TJADER: That's correct. But that applies to permanent change.

MEMBER SHACK: That's permanent changes. Okay.

MR. TJADER: That's different.

MEMBER SHACK: Okay. The 1.182 on the maintenance stuff gives you this particular limit. Okay.

MR. HOWE: That's where they come from, yes. And we're applying them to be consistent with maintenance rule.

So, good morning. I'm Andrew Howe with the Division of Risk Assessment. And I've been the primary reviewer from PRA License Branch for about the last year and a half for this risk-informed tech spec initiative.

And the first presentation will be to discuss the quality requirements of the PRA, the CRMP and what a license needs to provide to us for our review of the licensing amendment 4B program.

I'm going to discuss the requirements for PRA technical adequacy, the implementation of CRMP, license amendment submittal and review.

This is going to be fairly abbreviated because I know we presented this fairly often before to you.

Basically the PRA needs to be a full scope addressing the significant contributors. Obviously, internal events would have to be included. We require quantitative treatment of fires and other external events also must be included in the PRA or quantitative capability unless it's justified by the licensee that that particular source of risk is not significant for configuration risk management.

An example there would be if you had an external event that went directly to core damage like a large plug. Certainly not relevant what equipment is in or out of service. Therefore, you could exclude that from the scope of the 4B PRA.

It must address core damage frequency and large early release frequency, both metrics are applied in the 4B document.

Shutdown risk is not in scope. It is specifically excluded in NIE 06-09 at this time. So mode 5 and mode 6 for PWRs and I think mode 4 and 5 for BWRs are not in scope.

Next slide.

Regarding specifics for the different

PRAS. The internal events PRA model must comply with Reg. Guide 1.200 Rev. 1 which was issued, I believe, late January of this year and be consistent with capability category 2 of the latest standard.

There is also the requirement that we impose that PRA system success criteria needs to match with your design and license basis. So that's something that we need to look at for technical accuracy of the internal events PRA.

In regards to fire, Reg. Guide 1.200 Rev. 1 does not yet endorse a standard but it does provide some high level requirements. You must treat fires quantitatively but you can use a conservative bounding calculation if you don't have a plant specific fire PRA of some sort at this point.

CHAIRMAN APOSTOLAKIS: But the conservative calculations, I mean I remember the five methodologies from EPRI. Essentially it's a screening method. It eliminates occasions.

MR. HOWE: Right. Right. That would not be--

CHAIRMAN APOSTOLAKIS: So how would that be useful to anyone who wants to do this?

MR. HOWE: I don't think that would be useful.

CHAIRMAN APOSTOLAKIS: It would not be useful? So conservative you mean --

MR. HOWE: When I say conservative --

CHAIRMAN APOSTOLAKIS: -- you may identify your PRA, but in some cases where you don't have the numbers whatever, you can make it conservative assumptions?

MR. HOWE: Right. You bound the risk of the different configurations that you want to go to.

CHAIRMAN APOSTOLAKIS: Okay.

MR. HOWE: And you show the risk-informed completion time --

CHAIRMAN APOSTOLAKIS: Right.

MR. HOWE: -- legally would not be less conservative than you were using.

CHAIRMAN APOSTOLAKIS: And I think the same would apply to the seismic margins?

MR. HOWE: For plants where seismic is very significant, yes. I think some plants where it's really not a big deal --

CHAIRMAN APOSTOLAKIS: Oh, no, I understand that. Yes. I mean if you do the bounding evaluation and you declare that that particular event irrelevant, I understand that. Because those bounding calculation always bother me.

MR. HOWE: In all honesty as a reviewer, I think it would be a high hurdle to cross for a licensee to come in and say I don't have a fire PRA, but here's a way I'm doing it.

CHAIRMAN APOSTOLAKIS: Right. Right.

MR. HOWE: We'd have to review that pretty extensively to be able to conclude that it could be acceptable. Maybe if you're only apply, you know, a 4B program to a limited subset of systems that really aren't in the safe shutdown path for fire, you could justify that. But if you're a full scope plant, you're really going to need some kind of fire PRA.

CHAIRMAN APOSTOLAKIS: Very good. I'm glad you said that.

MR. EDAWAR: Mr. Chairman?

CHAIRMAN APOSTOLAKIS: Yes.

MR. EDAWAR: May I ask a question?

CHAIRMAN APOSTOLAKIS: Of course you may. You have to come to the microphone, though. Identify yourself, please.

MR. EDAWAR: My Zouhair Edawar. I'm the presenter from the HRA group. And I am on the Configuration Risk Management Forum Committee.

My question is about match PRA system success criteria with design basis. This is extremely

restrictive requirements on PRAs. The PRA success criteria are almost never a design basis success criteria.

MR. HOWE: Well, let me clarify that position a little bit. What I should have said was maybe not match, but present us what the differences are.

What our concern is here, I'll use an example is probably the best way to illustrate this. Let's assume that a licensee wished to apply a 4B program to their accumulator tech spec. They come in and say, yes, we model accumulators in our PRA, but we only use them for small LOCAs where we have this problem and we're depressurizing them. We don't care about them for large LOCAs and all that.

Well, then your PRA really isn't reflecting the tech spec requirements for those accumulators. Therefore, for a 4B plant they may need to either access what will be the impact of the LCOs they're proposing to use and show that it wasn't important or they may need to modify their PRA to put those accumulators in as a requirement, or make some argument as to why what they had was adequate.

MR. TJADER: Or take the accumulators off of the applicability of this program.

MR. HOWE: The fundamental thing we want is we want the reviewer to make sure if he has a thorough understanding of what the tech spec design basis is that they're proposing to apply 4B to and how the PRA models those systems in the success criteria. Understand the differences, if any, and assure ourselves that the risk-informed completion time that are being calculated are reasonable and reflect not only the risk but also the tech spec function that we're hoping.

MR. EDAWAR: Would you mind if you had one more example that I will bring, if I may, like the success criteria for auxiliary feedwater. A design basis may be 2000 gpm, but my thermo-hydraulics analysis will indicate 700 is enough to prevent core uncovery. The PRA will be based success criteria on 700 gpm. Will that be objectionable to by this bullet here?

MR. HOWE: Very possible. It very possibly would be. If it caused a -- let's say that your design basis said I needed two of three pumps but your PRA said one of three is acceptable? We want to have an understanding of why there should be a difference? Why can't you change your tech spec? What are the differences that are driving such a

significant change between the design basis success criteria --

MR. TJADER: And once we understand that, and once we understand that the PRA is more relaxed, that doesn't negate the fact that the licensee has to follow the tech spec requirement. The system will be inoperable and they have to be in the required actions for that inoperability. However, in determining what an appropriate completion time is, if it is determined that the system -- the feed water system or whatever system it is that's designed in you example, that you only need 700 to provide the safety function gallons, not the 2000, if the PRA reflects that, then there is nothing that should prevent and nothing in this program that would prevent -- in fact they're allowed to utilize that capability in determining a completion time for the required actions and the spec that they're in.

So they would still be inoperable. There's nothing that changes what that inoperability is for that system. What this does is allows you to reflect that the actual capability of the system is if it's reflected in the PRA to determine an appropriate completion time..

MR. HOWE: I discussed fire. Other

external events is the same basic way. Reg. Guide 1.200 provides high level guidance which we would review. And if external events were significant to the 4B process, we provide appropriate level of review until standards are endorsed.

Next slide.

I just wanted to talk about the issues regarding translation of the baseline PRA to the CRMP that you mentioned earlier.

The NEI 06-09 identifies the key areas that ourselves and industry have come up with as what needs to be looked at just to make sure that the CRMP has been correctly interpreted and translated from the baseline PRA model.

To highlight these issues. Basically the configuration impact of initiating events. For example, if I'm taking out a service water pump where I have three, does that effect the frequency of a loss of service water initiator year and does the CRMP properly account for that?

Truncation levels. If the baseline PRA model uses a different truncation level than the CRMP, that would need to be reviewed to make sure that we're satisfied that it cannot adversely impacted risk-informed completion times.

We have a requirement for benchmarking. That is, they need to demonstrate consistency by actually running cases in the CRMP to the baseline model and show that they could get in either identical or consistent results, that we can understand the differences if any.

PRA models are average risk models. So there may be events that are dependent on what time year you're in or what point in the operating cycle, like the unfavorable or moderate temperature coefficient. Typically PRAs treat those as fraction of a years, and that's acceptable. But in a CRMP it may matter whether I'm in the beginning of the cycle or the end of cycle based on my configuration. Therefore, that's another aspect we look at to make sure it's either treated or as in the case of our pilot plant, it's treated conservatively. It's simply assumed that they're always in the most conservative.

CHAIRMAN APOSTOLAKIS: There is another average, and I thought that's what you're referring to. For standby systems the average on availability between tests is one-half the interval between tests times the failure rate.

MR. HOWE: Yes.

CHAIRMAN APOSTOLAKIS: Which is the

average.

MR. HOWE: Yes.

CHAIRMAN APOSTOLAKIS: Now the actual one of course one minus E to the minus number T, but nobody wants to work with that. But that average remains.

MR. HOWE: We're accepting that. We're not requiring to say how many days --

CHAIRMAN APOSTOLAKIS: Okay.

MR. HOWE: may to. So that's sliding under a liability.

CHAIRMAN APOSTOLAKIS: Now the other thing is this -- your baseline is no maintenance, right?

MR. HOWE: Yes.

CHAIRMAN APOSTOLAKIS: The CDF starts counting from the moment you take anything out?

MR. HOWE: It's the delta between the zero maintenance case and what the actual configuration is, yes.

CHAIRMAN APOSTOLAKIS: All right. And now with online maintenance being done, I don't know the-- what fraction of the year is the plant in this configuration where nothing is out for maintenance?

MR. HOWE: Well, during my past history from the Shearon Harris plant, I don't think we were

ever in a condition where nothing --

CHAIRMAN APOSTOLAKIS: Yes. Right. IS that correct? Does anybody want to --

MR. GRANTOM: Yes. Pretty much.

This is Rick Grantom from South Texas Project.

We reached a zero maintenance state. Usually by the end of the work week we try to return everything back to service after the work week. Now we can sometimes are used for surveillance. So there's some aspect of that. But there's a mark to get back to the zero maintenance tech before we start the next work week.

CHAIRMAN APOSTOLAKIS: End of work week? You mean Friday? Is that what you mean?

MR. GRANTOM: Yes. Yes.

CHAIRMAN APOSTOLAKIS: So during the weekend you're saying it's zero maintenance? Is that essentially what you're saying?

MR. GRANTOM: Yes, except with the exception of sometimes we're having surveillance that are being done during that time.

CHAIRMAN APOSTOLAKIS: So then most of the year you are already above the zero maintenance condition, right?

MR. HOWE: I would say normally --

MR. GRANTOM: Yes. During any given regular Monday through Friday we'll be in some maintenance state for planned maintenance activities as part of a 12 week rolling preventative maintenance cycle.

CHAIRMAN APOSTOLAKIS: Therefore these you just work with allowed average time that you have already determined. No big deal because this is planned?

MR. GRANTOM: Correct.

CHAIRMAN APOSTOLAKIS: But if anything happens during that time, then you start thinking this way, perhaps.

MR. GRANTOM: This would give us an option to be able to deal with this differently now. Yes. If we had an emergent condition.

CHAIRMAN APOSTOLAKIS: Okay.

MR. HOWE: Sometimes I forget I'm a regular now and not a utility guy. I probably should correct the record of Shearon Harris where I worked.

If there was a radiation monitor broke or some relatively insignificant thing, but major safety systems, you know, it's routinely that we were in the zero maintenance with regards to important systems.

So I don't want to cast on my prior pilot plants.

MEMBER MAYNARD: I think it should also be pointed out that you do a number of systems, number of components and plants. So, yes, there may be work going on. All the safety systems are tracked and you have goals on the amount of time that they're unavailable. In fact, there's performance indicators. It's also part of the maintenance rule. And there's some, you know, fairly low limits for safety system unavailability.

So just not all maintenance out there is taking systems to an inoperable state, too.

MEMBER BONACA: I still have a question.

MR. HOWE: Sure.

MEMBER BONACA: The frontstops are really -- that you presented were deterministically the set--

MR. HOWE: They are what they are to the plant.

MEMBER BONACA: That's right. But I mean the plant could use Reg. Guide 1.174 to modify those, too, right? 1.177.

MR. HOWE: Yes, sir.

MEMBER BONACA: Okay. That seems to be what you've done at South Texas.

MR. GRANTOM: This is Rick Grantom again.

Yes, we have had some allowed outage time extensions, notably diesel generators 14 days, which is now the frontstop.

MEMBER BONACA: That's the frontstop. You know, conceptually it makes the -- I would like to see that change. I mean because of the issue that we discussed before. I mean, you're going from a deterministically based frontstop and then you are going to a PRA based completion time. And so it's okay. But, again, the significant changes of the frontstop.

CHAIRMAN APOSTOLAKIS: I mean it's called existing AOPs deterministically determined. I mean, that's another statement. It was a judgment of a bunch of people. I don't think it was --

MEMBER BONACA: Judgment, absolutely. But on occasions it was --

CHAIRMAN APOSTOLAKIS: Other things were deterministically, I can grant you that.

MEMBER BONACA: Yes.

CHAIRMAN APOSTOLAKIS: But this one was really what do you think, what do you think, what I think, let's do it this way.

MEMBER BONACA: Oh, yes. No, not even this Committee.

CHAIRMAN APOSTOLAKIS: Not even this Committee.

MEMBER BONACA: I will know how they say that at the first plant. But I think that after the first plant sets those to their own tech specs, it was like a cascading --

MR. HOWE: We've been doing pretty well over the years, though. I mean, we've been doing them for 30 some years without --

MEMBER BONACA: Very conservative values, too.

MEMBER SHACK: I mean somebody went through this process with the OOS, I mean if you hadn't already done the 1.177 would be all set up to go back and look at his frontstops

CHAIRMAN APOSTOLAKIS: Sure.

MEMBER SHACK: I would think.

MR. TJADER: I think once a plant implements 4B the only thing they might want to do is take a look at some of the very short frontstops and say well can I adjust by a longer time to allow me better time to --

CHAIRMAN APOSTOLAKIS: Yes. It adds flexibility.

MR. HOWE: Yes. I wouldn't expect somebody

to come in to a 4B plan and say well I want my 72 hours to go out to 14 days so I don't have to do any of this. No. This is the process we think is appropriate. We would prefer everybody to go to this rather than to use 1.177.

MR. TJADER: Yes. I think docket 4B we would be very skeptical about subsequent (4)(a) applications. And of course if they've had (4)(a) applications now, then obviously if they went to 4B then the implementation of the risk-informed completion time with respect to those systems that are (4)(a), it would be obviously less margin or less additional time that they could get from the frontstop.

CHAIRMAN APOSTOLAKIS: Is it true that -- my impression is that for plants that have extended the frontstop using Regulatory Guide 1.177 that the probability that they will get into this is very low.

I mean, South Texas I remember your diesel generators, you have 14 days but you never really reach 14 days, is that correct?

MR. PHELPS: This is Jay Phelps, South Texas Project.

Really the extended allowed outages that are currently just out of Reg. Guide 1.177 are not

frequently utilized either. Those are longer time frames. The value in the Initiative 4B is not going to be for those single system outages. It's going to be for the unplanned event for that opposite train component while you have its fellow component out of service is where this would actually be utilized.

CHAIRMAN APOSTOLAKIS: Well then this would be fairly infrequent?

MR. PHELPS: Yes.

MEMBER BONACA: No. The reason why I asked the question is that the frontstop, I use the word deterministically, but in the back of your mind for example an aux feed pump you have the accident analysis. And you think about int he accident analysis you're presenting a level of conservatism that is different from what you are assuming in your success criteria in the PRA. So there isn't any consistency there.

And if you change that frontstop, you would get a different value that is more coherent with this initiative.

CHAIRMAN APOSTOLAKIS: Coming back to the translation -- go ahead.

MR. TJADER: Let me just clarify something that Jay Phelps just said there.

I think he's taking you from a South Texas perspective. Basically South Texas is a very unique case where for many systems they have three trains where other plants have two. And therefore, their risk-informed completion times for many systems could be extensive.

And when he's saying that the application would be when the other train is out, that is for when they still have a capability, i.e, it's a two train spec, they have three trains; they still have a third train there available ready to go. So those tech specs are overly conservative.

What this explicitly does not do is permit not for inoperabilities of all trains of a system, it does not permit extension which relate to loss of safety function.

Sot hat implication I wanted to wipe off the board for those that were concerned about it.

CHAIRMAN APOSTOLAKIS: That's okay. So back to the translation.

MR. HOWE: I mentioned time here or time in cycle.

Recur reactions are also another elements of the PRA that may be applied without regard to looking at specific configurations. So there's a

requirement to make sure that if there are recovery actions that maybe shouldn't apply to certain configurations, that you address that.

And one I think is very important is the user interface. If you want to apply 4B to a certain tech spec, your CRMP, you should have a very easy way for the operator to identify how he tells the CRMP that this equipment is out of service to get that time. He shouldn't have to fumble around and try and figure out he needs to maneuver his computer to give him the tech spec answer that he needs.

CHAIRMAN APOSTOLAKIS: Now all of these are really requirements when you want to develop a risk monitor, is that correct? Because a risk monitor is not based directly on the PRA. You have to modify the PRA.

MR. HOWE: In these --

CHAIRMAN APOSTOLAKIS: Because the risk monitor is a real-time basis monitor.

MR. HOWE: Correct. And these are what we consider to be the things that need to be monitored.

CHAIRMAN APOSTOLAKIS: So if you already have a risk monitor on your plant, you presumably have done these things or if you develop --

MR. HOWE: No, not necessarily. I think

that -- I don't think there are specific -- how do I want to say this?

I don't think we have specific rules and requirements that are as detailed as this for the maintenance rule risk monitors.

CHAIRMAN APOSTOLAKIS: We don't.

MR. HOWE: It really is a tool to say oh on average what's the risk and -- this is where you want to run your tech spec completion times based on the output of this. And we are getting much more specific on what you have to do.

CHAIRMAN APOSTOLAKIS: No. But you're not regulating risk monitors. But what I'm saying is if a plant has a risk monitor for its own use, they have gone through this. Otherwise, it's not a risk monitor.

MR. HOWE: And what I'm telling you from my experience is, no, we didn't take a look, for example, at time in gear and time in cycle; we just accepted the average. So from a maintenance rule maybe early in cycle some of our risk inputs for maintenance rule are not exactly what they should be, but they give you a feel for it. But for the CRMP for 4B plants you're going to use that risk monitor.

CHAIRMAN APOSTOLAKIS: Right.

MR. HOWE: You're going to have to go back and make sure that you have addressed these or address them.

CHAIRMAN APOSTOLAKIS: Yes. Correct. Yes, the time year may be some special case. But if you want to have a risk monitor, you really have to watch -- how -- how are you handling common-cause failures here? You have one component down --

MR. HOWE: Right, I understand.

CHAIRMAN APOSTOLAKIS: -- extra risk management actions to make sure that the other --

MR. HOWE: Yes.

CHAIRMAN APOSTOLAKIS: -- one is not susceptible?

MR. HOWE: We discussed this pretty extensively about a year and a half ago. Should you-- when you have an emergent failure where a component is part of a common-cause group, should you adjust the risk-informed completion time until you are sure there is no common-cause. What we have decided is that the existing requirements for operability determination and assessment of extended condition are adequate for plant safety to date. And that modifying the risk-informed completion time conservatively on common-cause for emergent failure was a burden didn't give us

a commensurate safety benefit.

What we agreed to was that if you have emergent failure and you are in a risk-informed completion time, while you are still evaluating that extended condition to absolutely assure yourself that the other components are not in anyway effected by it, you would simply assess risk management actions that may be appropriate and implement then while you're in the RICT.

In other words, all you're already required to do an immediate op pump operability determination for redundant component and you're already required to do a thorough review of the extended condition. And this program doesn't relieve you of that burden. But we didn't think it was beneficial to require changing the numbers for the RICT based on the emergent failure. It was more appropriately handled by risk management issues.

CHAIRMAN APOSTOLAKIS: All right.

MR. HOWE: Okay.

Final bullet, there are administrative controls. The CRMP I think it's obviously has to be under software QA. There needs to be configuration controls so as to reflect the as-built as-operated plant. Users have to be trained in any procedures. It

should be under the corrective action program to assure that the tool is maintained "operable."

And that's what I have to say about the CRMP implementation.

Next I want to get into a license amendment review. What are we proposing for a licensee to submit and how are we going to conduct our reviews with the 4B plants. These aren't in any particular order, it'll just give you a flavor for what we are going to focus our reviews on.

The first thing is licensee must identify exactly which tech spec actions they want to apply risk-informed completion time to. So they need to identify what functions those systems provide in the design and licensing basis and how were they modeled in the PRA. You can't apply this to a system that's not in the PRA. This is a risk-informed use of the PRA. So applying it to a radiological ventilation system which it doesn't mitigate core damage, would not be appropriate.

I mentioned before, and I used the improper words ago so the same argument applies, if we want to see what the differences are between the success criteria and the design and licensing basis versus the PRA and understand those differences and

make sure we're satisfied that it's appropriate for the 4B program.

And, again, exceptions to that would be either justified or appropriate restrictions applied to their 4B program.

The licensee will assess against Reg. Guide 1.200 for the quality of their PRA models. Right now it's just internal events, but later for PRA we're going to look at a lot of detail about that. We expect to go to each site and do it all, just like we did South Texas. And this is one of the prime areas we would focus on.

If certain external events are excluded, we want to review why they've been excluded and make sure that justification is appropriate.

Next slide.

Most licensees only have at power PRA models. So in modes 1 and 2 are power and start up operation that are covered. And if they wish to apply risk-informed completion times to lower modes, again not in cold shutdown but the transition modes, they would have to justify whether PRA tools are appropriate. So that's another area we would look at.

We want to see their programs and procedures that assure that the PRA models and CRMP

are kept current with the plant.

And as I mentioned before, we'll look at the configuration risk management program in the areas we talked about for translating the PRA model to the CRMP, the admin controls, the scope and so forth.

And again, that last bullet we focused on how easy it is for the operator to use that CRMP tool. Does he really understand it? Because that's how he's going to comply with the tech specs.

Next slide.

We'll look at key assumptions and sources of uncertainty. Basically we're going to focus on how do they identify with them, how do they disposition them through sensitivity studies, were there any impacts on the 4B program and how would they propose to be handled.

That last bullet on cold shutdown out of scope, it's inappropriate. T should have been carried without a previous slide.

And we're going to look at their implementation, their program procedures, their staff responsibility for this and their decision process for risk management action. Typically when you extend the tech spec they could propose what comp measures they might put in place for an extended CT. Here it's

really just a program and a process to assess and put in place. So we want to understand that.

That is what we will be looking at when we review a 4B program.

CHAIRMAN APOSTOLAKIS: I have a couple of questions.

MR. HOWE: Sure.

CHAIRMAN APOSTOLAKIS: Let's see if I can find them.

This business of going back periodically but most every 24 months and compare with 1.174. I find that a little intriguing.

MR. HOWE: Okay. That was actually Bob's presentation, not mine.

MEMBER APOSTOLAKIS: But you will have to answer.

MR. HOWE: Pardon me?

CHAIRMAN APOSTOLAKIS: You will have to answer that. I don't think Bob should open his mouth.

But let me see if I can find my comment here.

You're saying in the SER here which I'm looking at -- there it is. A period assessment of the risk incurred due to the extensions of CTs is also required. This is an evaluation of the calculated

change in risk after implementation of our RMTS to assure that the guidance in Regulatory Guide 1.174 for delta CDF and delta LERF are met. If the RG limits are exceeded, then corrective actions must be implemented.

Let me tell you how I understand this and maybe you have comment. You have a licensee who takes advantage of this three or four times a year. And they do this on a regular basis. Then at some point even though the whole thing is based on the assumption of an increment in risk, which is temporary, at some point you wonder. You say wait a minute now, this temporary thing is way too permanent. They do this all the time. So if I calculate now the total risk for the three years, or whatever, including those incremental risks, I should have the delta CDF which I would treat as permanent. I should have delta CDF that should be less than ten to the minus five; that's really what you're saying here? Otherwise the guy has increased the risk permanently using a tool that is supposed to be for temporary increases. Is that the thinking here?

MR. TJADER: Yes. But I'm not sure then to the minus is the right five is the right number. I think, what is it --

CHAIRMAN APOSTOLAKIS: Well, it says

here--

MR. HOWE: Well, I was confused. Because you were looking at him but you told me to answer the question.

CHAIRMAN APOSTOLAKIS: I am reading from the document. It says "To assure that the guidance of Regulatory Guide 1.174 for delta CDF (ten to the minus five per year)," this is the upper bound in that CDF on the Regulatory Guide where above ten to the minus five is the normal acceptable region. Most of the time it's below, ten to the minus six, right? And then delta LERF is consistent, ten to the minus six. And this is, in fact, on page 4 it says. Page 4.

I mean, believe me, I wouldn't lie.

MR. HOWE: I think I understand --

CHAIRMAN APOSTOLAKIS: Do you have it?

MR. TJADER: Go ahead, Andrew.

CHAIRMAN APOSTOLAKIS: Oh, you don't have the important documents with you? Do you find it on page 4?

MEMBER BONACA: At the bottom of page.

MR. HOWE: In the SE?

CHAIRMAN APOSTOLAKIS: Yes, in the SE. The numbers are correct. I mean, I don't know why you are surprised. I mean, it is ten to the minus five.

MR. HOWE: Well, I'm good with it.

As the SE writer, let me tell you --

CHAIRMAN APOSTOLAKIS: Yes, please.

MR. HOWE: The direct implementation of any particular 4B LCO extension is to us a temporary change in risk. Therefore, the guidance in Reg. Guide 1.177 and especially in 1.177 which is a five E minus seven ICCG limit, associated LERF limit, don't apply because it's not a permanent change to the tech specs.

CHAIRMAN APOSTOLAKIS: Correct.

MR. HOWE: You assess it each time based on the actual risk. Therefore, that's why we applied the guidance in NUMARC 93-01 endorsed by Reg. Guide 1.182 because that's how they normally would assess configuration risk and maintenance rule space applying the tech spec LCO on top of that. This initiative is intended to make those consistent, and that's probably comparable.

We interpret, however, that the overall implementation of the program however many times you will use extended LOCs, once a year, once a month or whatever, as proposed by industry is consistent with Reg. Guide 1.174 in that it should only result in either zero or small increases in risk. But the problem for me as --

CHAIRMAN APOSTOLAKIS: Permanent decreases, though?

MR. HOWE: Yes. As the program determines -- that's our distinction. We say that each individual application is temporary, but you're putting it as a permanent program change to your tech spec. So we want to look at overall as you implement these risk-informed completion times sporadically what is it doing to the risk profile plan? We can't predict that. As Mr. Phelps indicated at South Texas mostly it's going to be for emergent failures that they can't predict.

So what we decided to do, what was proposed by industry and we've accepted in our safety evaluation, is that periodically not exceed I believe two operating cycles --

CHAIRMAN APOSTOLAKIS: Twenty-four months in the backstop.

MR. HOWE: -- or a two year -- I'm sorry?

CHAIRMAN APOSTOLAKIS: The backstop is 24 months.

MR. HOWE: Okay. All right. That they would go back and look at the past history of how they applied individuals and assess what was the incremental risk. In other words, they would have been

limited by their frontstop CT, but now they have this flexibility we've granted them so they incur an additional amount of risk temporarily. And maybe that gets offset by improved performance of the equipment or they didn't have to do --instead of doing five small outages, maybe they did one big one. So that's where you make it back to zero.

CHAIRMAN APOSTOLAKIS: Right. So --

MR. HOWE: But they're required to directly assess that, compare it to the 1E minus five CDF change and assure that this not being abused.

CHAIRMAN APOSTOLAKIS: Right.

MR. HOWE: And if they find in fact that the way we're implementing this program is causing risk creek, if I can use that term, they're required to go back and assess why is that happening, what can we do to change our program and get it back to as it was originally proposed.

CHAIRMAN APOSTOLAKIS: So I think I understood it correctly more from what you're saying.

MR. HOWE: Okay.

CHAIRMAN APOSTOLAKIS: That you don't want the people to use this and over the years to effectively decrease their CDF even though this --

MR. HOWE: That's correct.

CHAIRMAN APOSTOLAKIS: But another point that I maybe should be making clear here is that this delta CDF is not the delta CDF that is used in this 4B. This delta CDF in 1.174 is from the average CDF over the year that includes all sorts of maintenance activities and so on. It's not the zero maintenance.

MR. HOWE: The delta CDF that I'm looking for is I operate my plant in a configuration and I calculated that risk when I look beyond the frontstop. So I know how much extra risk I accumulated when I see that --

CHAIRMAN APOSTOLAKIS: Yes, extra risk.

MR. HOWE: -- I never would have accumulated by using a 4B plan.

CHAIRMAN APOSTOLAKIS: And you subtract that from what? Not from the zero maintenance.

MR. HOWE: I don't strike anything. That is the delta right there in my opinion.

CHAIRMAN APOSTOLAKIS: No.

MR. HOWE: No?

CHAIRMAN APOSTOLAKIS: No. Because that comes from the zero maintenance. You are measuring from the zero maintenance. 1.174 doesn't do that. It says here is the average CDF, five ten to the minus five, your delta CDF for primary changes is ten to the

minus five, so you increasing it. They are two different baselines. And you have to be careful with--

MR. BRADLEY: Biff Bradley, NEI.

Just to clarify. The risk you're measuring that Andy's speaking of is not above zero maintenance. It's above the frontstop. You don't start accumulating that risk until you've exceeded the frontstop. So you're looking at the delta of this application from the current tech specs to having 4B in place. That's the incremental risk.

CHAIRMAN APOSTOLAKIS: Well, that's not the same as the one in 1.174. 1.174 I look at the plant and I do a standard PRA that says, you know, these components are periodically tested. They are repaired and all these activities, human actions, it's an average estimate of the CDF over the year.

MEMBER BONACA: Unavailabilities included.

CHAIRMAN APOSTOLAKIS: Unavailabilities included, everything.

MEMBER BONACA: That's right.

CHAIRMAN APOSTOLAKIS: It has nothing to do with frontstops or zero --

MR. GRANTOM: This is Rick Grantom.

George, you're correct, Dr. Apostolakis. When we look at a rolling 52 week average, is kind of

what we're talking about here in this, the way we look at that is we do it in a zero maintenance state. But we normalize it against the average annual estimate of CDF. And so what we're measuring is if our average estimate is 1E minus five, then on the graph --

CHAIRMAN APOSTOLAKIS: The PRA result.

MR. GRANTOM: Yes. Our average is 1E minus five, we'll call that one and then we'll look at normalize it. Two is twice that amount. Three is -- and so we measure the rolling 52 week average and we take a look at our actual risk when we're looking at rolling 52 week averages are. And we look at that against the average. What does the actual risk do against the average. Because you're correct. We have average maintenance durations for planned and unplanned, average frequencies in the average model. And then we look at our actual configuration risk against that and are we within a band around that.

CHAIRMAN APOSTOLAKIS: Well, that's the application you're doing. I'm talking conceptually now. I'm trying to understand this and make sure that we're all on the same page.

When I implement the 4B we have agreed that I measure risk from the zero maintenances. So I assume there's no maintenances. Or if something is

out, it's out, right? The clock's started.

MR. HOWE: The differential to the zero maintenance.

CHAIRMAN APOSTOLAKIS: The differential. Exactly. Started. And using now my changes, I calculate backstops and so on and so on. And I that for a number of times over the year, always from zero maintenance.

Then I calculate the average risk I guess from these calculations over the year, right? And this will be the average increment from the zero maintenance risk CDF. But that's not the difference I have to go and apply to 1.174. I will have to take that extra and subtract from the average CDF that a normal PRA gives me that includes inavailabilities, it includes everything.

MR. BRADLEY: And I think it's simpler than that. You're just looking at the delta due to this application. Okay. So you're looking at the risk that you accumulate beyond the frontstop.

MEMBER SHACK: It's a different delta.

CHAIRMAN APOSTOLAKIS: And that's what I'm saying.

MEMBER BONACA: It's a different delta. Yes, it's a different delta.

MR. BRADLEY: You're not comparing it to an average model. All we're doing is every time you enter RMTS you're keeping track on how much risk above the frontstop you've accumulated. You add that up and that's your delta.

CHAIRMAN APOSTOLAKIS: In 4B I do that.

MR. BRADLEY: Right.

CHAIRMAN APOSTOLAKIS: But then on top of it every two years I have to go to 1.174. And I'm saying that's not the appropriate delta now.

MR. GRANTOM: This is Rick Grantom again.

You could look at two averages. One average that you said was the average of the configurations that occurred. And then there's the average annualized model which has average assumptions in there for lots of different things in there.

Okay. So there's an average that's associated with that. There is an average of the configurations that have occurred, and you can measure that value also. Now, whether one would take the delta between the average of the configurations and the average annualized model is, I think, what Dr. Apostolakis is talking about versus looking at the average CDF model and it's basically what I was saying with the rolling 52 week average. We're looking at a

rolling 52 week average of the configurations against the average annualized model to see if it comes within a band.

So when I was discussing this rolling 52 week average here is basically what I was communicating was I think almost the same thing that you were talking about.

CHAIRMAN APOSTOLAKIS: I suspected it was the same thing. But let's put it in a different way. One more way.

In 1.174 there is nothing like zero maintenance. We don't mention anything there like that,right? So we're saying that the baseline CDF, let's call it the baseline CDF, right, which is a result of a standard PRA assuming all kinds of things, whatever happens to the plant. Then you propose a change permanent, like extending the diesel outage time to 14 days, you do your calculations. Find the new CDF and you subtract it from that baseline, and that's now the measure of whether it's acceptable. That's one case.

If I didn't want to use 1.174, I have to use the baseline CDF and deviations from it.

In your case, though, your baseline CDF is not the PRA CDF, it's a zero maintenance.

MR. HOWE: It's lower.

CHAIRMAN APOSTOLAKIS: Exactly.

MR. HOWE: Which is lower.

CHAIRMAN APOSTOLAKIS: Which is lower.

So you do your calculations there. Within the 4B everything is fine; self consistent, we calculate the accumulative risk and all that. But then you have the extra requirement that every 24 months I have to take some of these results and go back to 1.174. And what I'm saying is when you go back make sure that you're using your baseline CDF now to calculate the delta CDF. Because that's what 1.174 says. That's all.

MR. HOWE: Actually, these were limiting. We make sure that we say -- and with from help for Dr. Perry -- I understand what you're saying.

I believe that if the licensee were to assess forget about Reg. Guide 1.174 for a minute. If you were to assess the actual delta risk that you accumulated greater than the frontstop, you just said my delta from the zero risk for the time that is there is this amount of risk. I believe that would be a conservative estimate for you to take the extra unavailability he got from his equipments, put it in his baseline CDF and calculate it.

So it's a conservative way to bound themselves to the Reg. Guide 1.174. But I think it would be acceptable to say for the last 24 months I've been using 4B. Here's my new unavailabilities of the equipment. I put those in my PRA and I don't see a difference, or my difference is within -- I think that would be --

CHAIRMAN APOSTOLAKIS: It seems to me that this should be clarified.

Gareth, do you have a comment?

DR. PERRY: Yes. This is Gareth Perry, NRR.

I think this is really -- I think what they're doing, and if I understand what Biff is saying correctly, that you really only are looking at the delta between the frontstop and the rest, what you're really doing is you're taking a sample of what the average risk would look like if you traced it through the year and then taken the difference between that and what the actual is, having added on the extra. So I think in the limit if you added up all the years you would get exactly to the Reg. Guide 1.174 calculation.

So I think this is just a -- it's a sample approach to getting at the difference. And I think if you also look at it as a practical way of implementing

principle 5 of Reg. Guide 1.174, which is to monitor the change, it's a way of doing that.

CHAIRMAN APOSTOLAKIS: I think you maybe right, and right now I can't follow the argument.

There are two or three delta CDFs in this safety evaluation that mean different things in my view. Some clarification would be useful. And if your argument is correct, which I'm sorry right now it's difficult to follow, then so be it. I mean, but just put it down; that's all I'm saying. Because if I go back -- for example, the tables that Bob showed us where, you know, neither endorse or accept or whatever, not disapprove, you had a delta CDF there, no? No. It was CDF. CDF. But again, those were -- I mean, was it from assuming zero maintenance or the average CDF? No, it was instantaneous. So it assumed zero maintenance, right?

MEMBER BONACA: The text does not specify that.

CHAIRMAN APOSTOLAKIS: That's what I'm saying. It's confusing. Well, I mean, I've read it.

MEMBER BONACA: It says what you have to do.

CHAIRMAN APOSTOLAKIS: Sure. Sure.

MEMBER MAYNARD: Well, I'm not sure. I

think you have to be careful with this evaluation we're talking about. And it may be good to take a look and for a sanity check, but if you have two identical plants side-by-side and you have one that's using this process and one that's not, one may have to take a system out twice to get something done where the other one can get it done within using this process. Actually in a shorter time than it may exceed frontstop, but he only has to take it out once instead of twice.

So I don't think the fact that you exceed the frontstop is necessarily in itself means that you've increased the overall risk. You may have actually decreased it by not having to take something out two or three times or maybe by having to live with degraded equipment.

So I think it's good to maybe look at it, but I think we have to be careful that we're not saying that this is definitely a definitive increase in risk --

CHAIRMAN APOSTOLAKIS: I think that we're discussing two or three different things now. But the point you just raised, Otto, is whether this is worth doing and if you do it, what conclusions do you draw, which is one point.

MEMBER MAYNARD: Yes.

CHAIRMAN APOSTOLAKIS: My point is more mechanical. That when you calculate the delta CDF and the delta LERF make sure you are doing it consistently with the regulatory guide you're using. If you use the 4B, it's one calculation, clearly stated. If you use 1.174 in my mind it's another calculation unless somebody proves otherwise.

So there are two issues. One is what you just said. I mean, having done it correctly, what conclusion do I draw now, which is a valid point.

MEMBER BONACA: But what I'm saying here is that paragraph is not correct. It's a correct statement.

CHAIRMAN APOSTOLAKIS: It's incomplete. It's incomplete.

MEMBER BONACA: What I'm saying is -- yes, but you want to have the recipe with, you know, how many tablespoons of this and whatever --

CHAIRMAN APOSTOLAKIS: No. No. I want this paragraph to continue and put a statement as to what-- or alert the user to the fact that these delta CDF now is the 1.174 delta CDF. Why is this a big deal?

MEMBER BONACA: That is not a big deal.

MR. HARRISON: Dr. Apostolakis, Donnie

Harrison from the PRA Branch.

CHAIRMAN APOSTOLAKIS: It shouldn't be.

MR. HARRISON: We'll take that comment and go back and reread the text. And if we're talking about different delta CDFs and how they're being used, we'll clarify that in the SE.

CHAIRMAN APOSTOLAKIS: Yes. Yes. That's all I'm saying.

MR. GRANTOM: And, Dr. Apostolakis, this is Rick Grantom.

If I might add there, that that's in fact how we're doing. I call it the rolling 52 week average, but every data point is the average of the actual configurations from the previous 52 weeks we've been in. So it is in fact measuring what you're talking about.

CHAIRMAN APOSTOLAKIS: Yes. And again, the issue is not really how the pilot is doing. It's what we're going to do in the future.

MR. HARRISON: And I think it's worth clarifying that so that we don't have the confusion, as well as point out as Dr. Perry pointed out, which is this is a way of implementing the fifth principle performance monitoring to make sure that the decisions you're making are being maintained. And that --

CHAIRMAN APOSTOLAKIS: Now our lives are run by 1.174.

MR. HARRISON: Okay.

CHAIRMAN APOSTOLAKIS: There is always a principle that applies to what kind of breakfast I'm going to have.

Are you okay now? Are you fine. Okay.

MR. HOWE: I understand your comment. I guess my words are misleading in the SE --

CHAIRMAN APOSTOLAKIS: I'm not saying they're misleading. They just need to be clarified.

MR. HOWE: The licensee who implements 4B needs to do the calculation properly to assure they're in compliance.

CHAIRMAN APOSTOLAKIS: I think that's a very smart thing that you require them to do, as long as you put two -- clarify two things here. One is the mechanics of doing it and second what Mr. Maynard just said, what conclusions do you draw from this. Be careful. That's all. Okay.

MR. HOWE: Okay.

CHAIRMAN APOSTOLAKIS: So you think we're going to have that by the full Committee? I mean, it's just a line?

MR. HOWE: Absolutely. Sure. Sure.

CHAIRMAN APOSTOLAKIS: Yes. Very good. Thank you.

MR. HOWE: That concludes my first presentations. I'm ready not to discuss the South Texas audit results and what we --

CHAIRMAN APOSTOLAKIS: Yes. And we're close to an hour and a half. So following my principle 1.174, we will break for 15 minutes. We will reconvene at ten minutes past.

(Whereupon at 9:48 a.m. a recess until 10:06 a.m.)

CHAIRMAN APOSTOLAKIS: Okay. We're back in session.

MR. HOWE: Thank you. My second presentation is on South Texas Project audit that we performed in June.

Next slide.

Talking about the purpose of the audit and what we found.

Our logistics of this, we have four experienced PRA analysis including two of our current senior leadership positions in PRA, Dr. Perry and Mr. Steve Laur. We also had the senior reactor analyst from the Region who was -- what was his name? I don't know. Had some tech spec expertise, Bob Tjader. And

we also have the South Texas Project Manager Mr. Thadani there. So we had a pretty well experienced team looking at a variety of different aspects of their 4B program.

We spent 3½ days on sight in late spring. The weather was beautiful.

We had a prewritten audit and review plan that was developed by the reviewers prior to the visit, and that was shared with the licensee so they could be well prepared to have the information available to us.

The purpose of the audit, and I just quoted from our audit plan, was to provide assurance that the PRA model configuration risk management program and supporting activities are adequate to conclude that the implementation of the proposed RMTS amendment request will not challenge public health and safety. That's a pretty high level goal. We also looked at a lot of details that would support that statement.

MR. TJADER: Mike Runyan was his name.

MR. HOWE: What was that?

MR. TJADER: Mike Runyan.

MR. HOWE: Mike Runyan, yes. He was the senior reactor analyst.

The scope of the audit was to establish the technical adequacy of the licensee's PRA models where we didn't have standards. This was specifically the fire, the seismic and external events.

South Texas had submitted the high level information required by Reg. Guide 1.200. This was a more detailed look to make sure we were satisfied that those models could support a 4B program.

We wanted to look at the development implementation of the CRMP to address the issues we talked about earlier.

We wanted to look at the status of the licensee's training and their procedures for their personnel to support RMTS' implementation because this is a very significant change in tech spec compliance philosophy.

And going along with that, we wanted to look at the overall plant safety and risk culture of their organization. And this is a soft thing, but really what we're looking for here is if we're going to use the PRA for tech spec compliance, does the line management at the site really understand PRA and to the extent and we were going to believe it and say, yes, that's a good way to run my plant.

Just briefly the overall conclusion was

that the South Texas PRA models, their configuration risk management program and tools and their procedures and their training appear sufficient in scope and detail to support the license amendment request. So we didn't find any outstanding issue that would be a show stopped, if you will.

I'm going to go into some of the details now of what was looked at and some of the findings.

The first area was the fire PRA. And the fire PRA at South Texas was developed, I believe, in the late 1980s and it was reviewed by Sandia National Labs documented in a NUREG.

They identified it was updated in 1994 due to fire barrier issues. And that they use a successive screening approach. This was reviewed in some detail by our reviewers. In fact, that was really the main focus area; are we screening fire scenarios that for certain configurations could be risk significant, and therefore those need to be put back into the model. In fact, one of the findings that -- discusses, they needed to go back and kind of take a look at some of those and assure themselves that it wouldn't be appropriate to maybe include more of the site scenarios in their fire PRA.

It also identified that there was

suppression credit or credit given for fire suppression pumps, but it was adjusted based on whether pumps were available. I think they had two or three -- three pumps. Thank you. And if one was out of service, they changed the credit they would give. And that's a positive aspect of this for configuration risk management.

Sort of kind of just a brief flavor for what was looked for the fire PRA. And there was probably a good day spent by two reviewers, of two SLs, as a matter of fact looking at that in some detail.

With regard to the seismic PRA, South Texas is in a low seismicity zone, so it's not something that we considered to be significant. They do also assume that failures from seismic events are 100 percent correlated. So if you get an event that's of sufficient size to fail one component, it's going to fail all the components that are similar to that. So it's a conservative analysis and we didn't find any issues there.

Some time was spent on the internal events because we do have a standard for that. Fundamentally we found that we can agree that they meet capability category II of the existing ASME standard. There was

some additional detail we felt was necessary in their documentation to make sure they clearly state that they meet capability category II as opposed to just meeting the standard.

We also did review some instances where the PRA model scope really wasn't complete enough to match up with tech spec functions. And this lead to in their resubmittal after the audit some of the tech specs that were in scope originally were removed from scope. They now realized or decide that their PRA model at this time didn't support it. But they may have to go back and add those systems into their PRA and make a later submittal. So there were some changes that came out as a result of the internal events review.

Next slide.

Prior to the South Texas CRMP their program, as we've said, is a database look up of pre-solved configurations. This is convenient in terms of translating the model because you're not putting the model in place for online user manipulation. You're simply pre-solving it, getting it numbers and they simply have a database that they're checking to see what their configuration risk is.

They identified that there are QA

requirements that review these results. Obviously, with 20,000 cases you're not going to a thorough review of every single case, but you do the up front checks on the process to make sure that what you're getting should be reasonable.

They identified that there was no credit given for any repairs of out-of-service equipment for the CRMP, which is appropriate.

And with regard to time dependent variables and cycle dependent variables they simply assumed the most conservative time of year/time in cycle as opposed to assessing it. So that's acceptable for 4B.

We did find some issues with is there an easy association between what tech spec I'm in versus how I maneuver the CRMP. And South Texas took that and is looking at their procedures and programs. And based on their last submittal we're satisfied with their consolidation.

Next slide.

Uncertainty analysis was another we looked at. This was not yet completed. South Texas was just finishing up the final revision of their PRA and was getting ready to do the uncertainty analysis. So we couldn't look at results. That's been done subsequent

as part of an RAI. But they did make a presentation to discuss what they plan to do. And we had a meeting to give us an opportunity to provide them some feedback and our insights on what we think how they ought to be accomplishing this task.

MEMBER ABDEL-KHALIK: Can we go back to the previous slide, please?

MR. HOWE: I'm sorry. Absolutely.

MEMBER ABDEL-KHALIK: The comment about no time dependent variables assuming the most conservative value. Are there any future core designs that would violate this?

MR. HOWE: Are you talking about the moderate temperature coefficient?

MEMBER ABDEL-KHALIK: Right.

MR. HOWE: I can't speak for South Texas Project.

MEMBER ABDEL-KHALIK: You know, say for in general.

MR. GRANTOM: I can tell you right now that our current tech specs don't allow a positive moderator temperature coefficient, which would be the one variable that would be considerably different. We're always required by our current tech specs to have a negative zero or negative moderator temperature

coefficient.

MEMBER ABDEL-KHALIK: But you're using the less negative value as of now, I guess?

MR. GRANTOM: This is Rick Grantom.

We assume the most conservative throughout the whole year for everything.

MEMBER ABDEL-KHALIK: Up to this point, meaning up to the core design, things you have documented so far. I mean, you still can come up with a core design that would not violate the positive MPC requirement and yet would be more restrictive than whatever you've been doing so far?

MR. GRANTOM: In terms of the PRA translation of that, though, we would assume the most restrictive most conservative assumptions in the risk analysis relative to that.

MEMBER ABDEL-KHALIK: Okay. I thought these were all pre canned?

MR. GRANTOM: They are, and the criteria in the analysis assumes the most conservative value with regard to things like moderator temperature coefficient.

MEMBER SHACK: But if you had a whole new core design, you'd have to rerun these?

MR. GRANTOM: Right. If we had the core

design that did that, that would impact tat, yes we would have to update it at that point in time.

MR. HOWE: Just to follow on to that, this was a snapshot audit of where they are today. But the other thing we looked at is their programs and procedures that required them to access, are you're mentioning. If they make design changes on anything that could effect the CRMP look up cases, their programs and procedures require them to update. That's a feature that we look for in a 4B plan.

MEMBER ABDEL-KHALIK: Thank you.

MR. HOWE: Going to this one.

Okay. So in their presentation the licensee identified or basically presented their plans, which is they're going to identify the key uncertainties using industry -- I think they were draft documents at that time, as guidance for how they would identify those key sources.

They would assess those key uncertainties impact on any of their configurations where the time was already less than the 30 backstop. In other words if you have one that's already 100 and some days, it's still unlikely that uncertainty could significantly impact that. And we felt that was reasonable.

They were going to perform any sensitivity

studies required. And per NEI 06-09, if necessary, they would implement any program restrictions or comp measures necessary to address those key sources of uncertainty.

CHAIRMAN APOSTOLAKIS: Now you have a statement in Safety Evaluation Report that the Staff has not reviewed this document and the NRC neither endorses nor disapproves its methods?

MR. HOWE: Yes. The same version we used for the ten minus three, ten minus four.

CHAIRMAN APOSTOLAKIS: It starts with review each individual licensee's process for identifying assessing key uncertainties. Why haven't you reviewed this document?

MR. HOWE: I haven't personally reviewed it. The NRC is in the process of reviewing it. In fact if they doesn't mind, I'll ask Dr. Perry to comment ont he uncertainty document.

CHAIRMAN APOSTOLAKIS: Do we have that, by the way? Does the ACRS have this document?

DR. PERRY: This is Gareth Perry, NRR.

I doubt it. We've seen draft versions of it.

MEMBER SHACK: We had a presentation on it, though, didn't we? I don't remember.

DR. PERRY: Well, you had a presentation--

MEMBER SHACK: Their in engineering.

DR. PERRY: -- on an early -- yes, before.

MEMBER SHACK: Oh, way back. Yes.

CHAIRMAN APOSTOLAKIS: That was more than a year ago.

DR. PERRY: That was a long time ago.

MEMBER SHACK: Yes.

CHAIRMAN APOSTOLAKIS: But is it possible for us to get it?

DR. PERRY: I think you should probably ask Ken Canavan from EPRI.

MEMBER SHACK: But they've submitted it as a license --

MR. CANAVAN: Mr. Chairman, if you would like it --

CHAIRMAN APOSTOLAKIS: If I would like it? No. Does it look like I don't like.

MR. CANAVAN: Ken Canavan from EPRI.

Mr. Chairman, we can make the documents available to you.

CHAIRMAN APOSTOLAKIS: Thank you.

Since you're here now, I was reviewing two documents from EPRI, they're pdf. And somehow you do

something to them and we cannot mark them, we cannot highlight anything. Why? This makes it so inconvenient. I mean as long as you give us the document, what's the point of not allowing us to highlight or to make comments on it?

MR. CANAVAN: It's not my personal decision to lock the pdf. What they do is lock the pdfs.

CHAIRMAN APOSTOLAKIS: Yes.

MR. CANAVAN: The point is to protect copyright. So it's our publications.

CHAIRMAN APOSTOLAKIS: I don't understand how copyright is protected that way since you are giving it to me.

MR. CANAVAN: I'm not sure either.

CHAIRMAN APOSTOLAKIS: Can you tell someone over there that this is very inconvenient?

MR. CANAVAN: I will register your point.

CHAIRMAN APOSTOLAKIS: Thank you very much.

It's so inconvenient.

MR. HOWE: I hope the document we provided in pdf will unlock.

MEMBER SHACK: NRC doesn't know how to lock the documents.

CHAIRMAN APOSTOLAKIS: Oh well.

So can you give us an example of an uncertainty that was identified and how it was handled?

MR. HOWE: I remember one of the key source of uncertainty was the ventilation systems for the switch gear and control room, Bob.

Mr. Grantom could probably give you one.

MR. GRANTOM: This is Rick Grantom.

One of our key sources of uncertainty is loss of electricity auxiliary building HVAC, the heating, ventilating, air conditioning at South Texas Project. And this particular initiating event is uncertain because we don't really know exactly at what point in time if you lose fans to these rooms, these rooms house safety related electrical switch gear, the motor generator sets for the rod control systems in there. So high heat load in some of these rooms and we lose van cooling, what's the heat uprate, how long does it take, what are the thermal fragilities of the equipment in there and recovery actions that we may be able to do?

So we conservatively modeled it as an initiating event and also within a time constraint. And it cascades itself eventually to an internally

generated station blackout. Even though you have power on the grid, you can't get it through the switch gear rooms to do anything. And so it cascades itself to an internally generated station blackout which causes an importance to determine generator auxiliary feedwater pumps. We have an alternate reactor coolant pump seal injection capability with the positive displacement pump powered diversely from a technical support system centered diesel generator. And so it causes these components to be somewhat important. But that's an area of uncertainty that we've tried to examine and look at that. And it's still a large area of uncertainty.

HVAC being taken out of service has a big impact on the results when you assume that being out of service. And it's driven by common cause failure of the fans. So that's one area that's --

MR. HOWE: I remember it, I don't know if there were uncertainties.

MR. GRANTOM: -- that we have a high area of uncertainty.

The reactor coolant pump seal LOCA, we used both models and the different seal LOCA models over there to try to address that issue on the uncertainty about the seal LOCAs.

Human error is another large area of uncertainty, as it is with everybody.

The steam generator bypass where you have a bypass of a the tube rupture going to a larger release, the fraction of that release is another large uncertainty that we do analysis on that area.

And those are really the kind of big ones.

The last one on the stup tubes is uncertainty because it effects a larger release frequency at that point in time. And in fact, this is a dominant contributor now based on the analysis what we have.

CHAIRMAN APOSTOLAKIS: So the general approach was to be conservative and assume the worst?

MR. GRANTOM: Generally be conservative. We were conservative that we assumed that the motor generator sets are going to overheat, the plant's going to trip on loss of electrical auxiliary HVAC. So now once we have a trip, now we have an initiator or now the plant's going to go. And if there is not any means by which to remove heat from the rooms or from the building, then we predict that conservatively that all the equipment is going to fail. This is why we cascade and switch conservatively to an internally generated station blackout. Pretty severe that we

don't allow any equipment at that point in time, other than these other ones that I talked about.

CHAIRMAN APOSTOLAKIS: These sound to me like are all of model uncertainty type.

MR. GRANTOM: Yes. This would be --

CHAIRMAN APOSTOLAKIS: I mean parameter uncertainty really is irrelevant here, is it not?

MR. GRANTOM: In this regard, yes, for this application parameter uncertainty is pretty much irrelevant. This is an epistemic uncertainty, a modeling uncertainty that's associated with South Texas Project. And it's driven in a sense because of where we are in South Texas. It does get quite hot. And we tried to evaluate the room, heat up of the systems, but all that's based on having fans, some motive power to move air through rooms. And when you calculate through the PRA, ultimately you find it's common-cause failure of the fans that drive the results.

CHAIRMAN APOSTOLAKIS: Yes.

MR. GRANTOM: So these fans right now are extremely important in the risk modeling and our ability to deal with that. So, yes, in a sense we handled it conservatively.

CHAIRMAN APOSTOLAKIS: Very good.

MR. HOWE: Just to finish up, the NRC team listened to their presentation, had some recommendations based on our visit here at the site.

CHAIRMAN APOSTOLAKIS: So at some point you would same something about NEI 06-09? It is under review now?

MR. HOWE: Not 06-09. That's our guidance. You talking about the EPRI document?

CHAIRMAN APOSTOLAKIS: Yes. And the EPRI document is different from NEI 06-09?

MR. HOWE: Yes. Yes.

DR. PERRY: Yes. This is the guidance document for tech specs.

CHAIRMAN APOSTOLAKIS: So the EPRI document is 1009652.

DR. PERRY: Okay. Something like that.

CHAIRMAN APOSTOLAKIS: Which is referenced by NEI 06-09?

DR. PERRY: That's correct. Yes. And to clarify that, that's one of the documents that we're supposed to be reviewing in the forthcoming NUREG on uncertainty analysis.

CHAIRMAN APOSTOLAKIS: Okay. So all this is one effort?

DR. PERRY: The --

CHAIRMAN APOSTOLAKIS: We are told that there is already a good draft of this NUREG report on uncertainty events.

DR. PERRY: Okay.

CHAIRMAN APOSTOLAKIS: We are told that there is already a draft.

DR. PERRY: There is a draft.

CHAIRMAN APOSTOLAKIS: Okay.

DR. PERRY: And I can tell you that we do have some concerns about the EPRI document. Not so much the process, but the details.

CHAIRMAN APOSTOLAKIS: The what?

DR. PERRY: The details.

CHAIRMAN APOSTOLAKIS: Okay. But ultimately it would be the NUREG report that really will be used in these cases?

DR. PERRY: That's right, yes. Well, that would be the one that would provide the NRC's position on the EPRI documents.

CHAIRMAN APOSTOLAKIS: And we will hear about it some time in the near future?

DR. PERRY: You need to talk to Ms. Gillian about that.

CHAIRMAN APOSTOLAKIS: Okay.

MR. HOWE: Next slide. Oh, I'm sorry.

That's all I had to say about uncertainty.

We also looked at the human reliability analysis. South Texas was in the process of finishing up their update to use the EPRI calculator, which is they're going to use a more robust method. They currently were using the FLIM, which I've written down what these acronyms mean just in case somebody wanted to know.

A peer review was identified as being required by the ASME standard because they are changing methodologies. And the Staff made some observations regarding the methods used in the supporting t/h analysis.

MEMBER ABDEL-KHALIK: What does FLIM stand for?

MR. HOWE: You're going to ask me that. Failure or likelihood index method. Now you know as much about it as I do.

MEMBER MAYNARD: And what gave the opportunity to --

MR. HOWE: Just, you know, cause-based decision tree, human cognitive reliability operator reactor experiments. And now I've covered all my acronyms.

CHAIRMAN APOSTOLAKIS: So we had

everything on this yesterday.

MR. HOWE: Well you should all know all about it then.

CHAIRMAN APOSTOLAKIS: Never heard of it.

MEMBER MAYNARD: I've gone through the EPRI notes and not used the -- I wanted to ask.

MR. HOWE: Okay. On CRMP implementation, we reviewed the implementing procedures. We found them to be consistent with the RMTS guidance and have identified the four procedures that we reviewed, which included the actual program, operations program for configuration risk management, the risk management actions procedures which they used to determine what comp measures might be used during a risk-informed completion time as well as their software QA and how they maintain configuration control.

We also attended ongoing operator training for RMTS. And I personally found this very useful to me as a reviewer. It helped me see how the operators were really understanding their role in the RMTS program, the RICTs. And I was favorably impressed with the knowledge level. They seemed to understand it and accept it. I asked some tough questions, as I recall. They were handled fairly well by the South Texas PRA staff. But my overall impression was they

understand core damage and LERF and their tools and they're very comfortable using them from a textbook compliance point of view. And that's what we were looking for.

MEMBER MAYNARD: Is this part of their continuing training? Do they train their operators on this or have a session --

MR. HOWE: I'll have to defer to South Texas.

MR. PHELPS: This is Jay Phelps.

Yes. Actually we have included risk managed tech spec training in our licensed operator continuing requal training program for the last four cycles. Probably have included about five hours of classroom training to date just on this in addition to some additional hands-on training that we'll be performing during this upcoming refueling outage with someone from Rick's group coming over there using the tool as it's finally being modified. And a little later on I'll show you some screen shots of how that tool looks and how that works for us.

MEMBER MAYNARD: Okay.

MR. HOWE: Next slide.

Finally, the risk and safety culture. We took a look at how risk management is used in plant

operations, how it's an element of the plant safety culture and the overall risk and safety culture. Interviews were conducted with an I&C technician on up through several strains in management. Again, the overall finding was that risk assessment management is really integral to daily operation of the South Texas Project, which is something they've been telling us for some time during our reviews, and we confirmed that.

Finally, conclusions. Again, overall STP appeared to be on the right track to implement RMTS. There were some areas that were considered in the request for additional information as part of the license amendment request. Again, as I mentioned, to justify that the screening applied to fire scenarios was appropriate and that they were going to go back and reread some of that.

Some of the fire PRA data was a little bit dated and maybe consider that in the uncertainty analyses.

They need to update their Reg. Guide 1.200 assessment and provide some more details. And, again, go back and take a look at some of the tech specs and matching them up to the CRMP to make sure the operator really can implement for each of those tech spec of

this program.

And that was the result of findings of our audit. That's all I have.

CHAIRMAN APOSTOLAKIS: Any problems, any questions?

Thank you very much.

MR. HOWE: Thank you. Appreciate it.

CHAIRMAN APOSTOLAKIS: The next presentation is from Mr. Canavan on the HRA models for use.

MR. CANAVAN: I brought my electronic brain, my laptop.

Good morning. I'm Ken Canavan. I'm with the Electric Power Research Institute. And I'm the Program Manager for their Risk and Assessment Management Programs at EPRI.

Thank you for the opportunity to speak in front of you. I kept my presentation extremely short, two slides. And feel free to ask as many questions as you'd like.

I understand there were two topics. The first topic was human error probability treatment in 4B. I know you've heard a lot about human errors in the last couple of days, which is one of the reasons why I kept the slides relatively short.

In general, the human error reliability treatment or the human error probability treatment in tech spec 4B is fairly straightforward. In general, there are no changes made to the HEP values or performance shaping factors or the actions.

This treatment is generally slightly conservative, the reason being when you do an HEP for the average plant in the average model there's a little bit more uncertainty associated with what condition the plant's truly in. And in this case, the configuration is well known by the operators. So we're in a situation where I think they understand more adequately where the plant is in terms of its configuration. And in addition, there are risk management actions for certain configurations that fall into either a medium or a high risk type area. So there's even more controls and more understanding of the actual plant configuration.

And in the case of STP, I just thought I'd mention, and actually it was on one of the previous slides, they are currently using the HRA Calculator, primarily a THERP-based methodology. Since you've heard so much about that in the last few days I thought I'd --

MEMBER SHACK: Yes, but we got a different

one in the last slide.

MR. CANAVAN: Yes. They were using FILM, but they were transitioning to the HRA Calculator. So on the last slide they were saying "transitioning to," and I believe that that's transition been completed. And I see Rick shaking his head yet.

MEMBER SHACK: But it wasn't THERP they were transitioning to?

MR. CANAVAN: No. Transition to THERP from FILM.

MEMBER SHACK: Oh. That's not what he said in the previous slide.

MR. CANAVAN: Take a look.

MEMBER SHACK: It said you were using, you know, the empirical-based one, HCRORE and cause-based.

CHAIRMAN APOSTOLAKIS: I think most people use that.

MR. CANAVAN: Yes. Maybe they are going to -- you can use those methods within the Calculator.

MEMBER SHACK: Yes. I go from one slide to the next slide, it just catches your attention. That's all.

MR. CANAVAN: Yes.

MEMBER SHACK: Which one are we using? THERP or --

DR. PERRY: Maybe I can answer this, Rick. I think you're using both. Because you're using the CBDT for the cognitive part and THERP for the execution.

MEMBER SHACK: Ahhh.

MR. CANAVAN: There's two parts of the --

DR. PERRY: Yes.

MR. CANAVAN: Right. Okay.

And my second slide, again, I'll start with sort of the generic approach to the treatment of uncertainty in tech spec 4B. In the case of parametric uncertainty it's performed for the base model as it's normally performed. And in this particular case for a delta risk type calculation, there's generally no significant change. I believe the Chairman had indicated it was generally irrelevant, which is true. So there's nothing in particular in general done for parametric uncertainty.

And in the case of modeling uncertainty the EPRI guidance documents weren't available at the time of the development of this particular submittal. They were in draft. But the general process of treating modeling uncertainty in tech spec 4B is to perform the base case methodology for the base case PRA. And I can put up the flow chart. You saw that

about a year ago and it has not changed since then.

And the applications guide takes you through doing a set of series of what I call CANDOR, CANDOR or standard sensitivity cases looking at HRA and CCF, the no maintenance model and data. So it looks at your database -- it uses those standard sensitivity cases to bound many of the sources of uncertainty that you may come across in your model. So when you just find a source of uncertainty that fits within one of the generic cases, you may just move on. In cases where it doesn't fit within the generic case, you may do a specific sensitivity case for that source of uncertainty where the risk achievement worth of that source of uncertainty is greater than two. And that can be SSEs -- source of uncertainty can be SSEs and individual SSEs. It an be a phenomena or other items that are sources of uncertainty. And there's a process that gives you a set of generic sources of uncertainty and then you can augment that with plant specific.

And there's a new focus in the uncertainty guide, and they're going to be revised based on some of the Staff's concerns on the methodology. And that is to put a new focus on new sequences or new phenomena that doesn't appear in the original base

case model. So as you go do an application if you create new sequences, that's actually in the methodology now but it's certainly not emphasized. And the Staff would like us to consider increasing the emphasis on that. So that's one of the changes.

We're also in some discussions of the criteria.

So the overall methodology isn't really changing, but there are some details that we're working on to improve its applicability.

And in the case of STP they did not initially use the EPRI applications documents uncertainty, primarily because they were in draft at the time. But they went back and did a consistency check with those draft documents. So they were certainly consistent with the methodology.

And the Chairman has asked if he can get copies of those documents. There are actually two. The first one is the *Guideline For The Treatment of Uncertainty In Risk-Informed Applications*, it's a technical basis documents. That's 350 pages of everything you ever wanted to know about uncertainty, so the technical basis sort of covers the full range of technical issues. That was published in December of 2004. And that's the document you refer to 10096523.

The *Guideline For The Treatment of Uncertainty In Risk-Informed Applications* is the applications guide with two pilots of that applications guide. That was completed in October of 2006. And the number of that report is 1013491.

We probably will be, based on comments that we received both from the industry and from the Staff, revising those documents to change the criteria and some of the emphasis within those reports to stress --

CHAIRMAN APOSTOLAKIS: But you think you can send us copies?

MR. CANAVAN: You had indicated you would like them, yes, I will send them to you.

CHAIRMAN APOSTOLAKIS: Thank you.

MR. CANAVAN: I'm not sure I can get publications to let you comment in the pdf --

MEMBER SHACK: We'll take care of that.

CHAIRMAN APOSTOLAKIS: Oh boy. You really take away a lot of the usefulness of the electronic document.

MR. CANAVAN: Well, lawyers do that. That's their job.

And that actually concludes my presentation. I intended to be brief because I thought

that there would be a lot of overlap, and there indeed was.

CHAIRMAN APOSTOLAKIS: Very good.

Any questions?

Thank you.

MR. CANAVAN: Well, thank you.

CHAIRMAN APOSTOLAKIS: So now we are moving on to what? To --

MEMBER SHACK: Just coming back to that. Now a particular case that Rick was talking about, would that come out when you were doing these RAW things, when you were looking at components that had risk achievement? In this process is that where you would find something like that or you just knew that to begin with and it wasn't part of this process?

MR. GRANTOM: What are you referring to?

MEMBER SHACK: You know the EPRI treatment says we go through these things where we look at RAWs and I was asking, you know you brought up a particular case that was sensitive for you. And I just wondered if that would come out of this study or you just knew that?

MR. CANAVAN: It is a direct result of the study. You might also know that one of the things that we learned from the pilots we did is a lot of

these you already know. You know, loss of off site power is an important contributor to the profile. Therefore, things that relate to that --

MEMBER SHACK: Well, I was thinking of the HVAC.

MR. GRANTOM: Yes, we do a lots of different sensitivity studies and look at both risk achievement worth and fossily and look for those kinds of impacts of what drives those areas. Part of that is part of diagnoses and error finding, but another piece of that is just to learn what are the dominant contributors and why they're there and understanding that type of thing. So we do see a lot of those things. That's why we saw the fact that EOD frag was such a dominant contributor in this and understanding the reasons why that is. Then you see losses of off site power and the other types of contributors.

And when we put together a whole risk profile of initiating events you see that -- when you group them together loss of EAB is there, but we still have the LOCA spectrums of things that have a percentage contribution, tube ruptures, loss of off site power is one of our largest contributors. And then we have separated out EAB HVAC separately from that.

CHAIRMAN APOSTOLAKIS: Steve?

MR. HESS: Thank you. For those who don't know me, I'm Steve Hess with the Electric Power Research Institute. And following my manager's lead, I too intend to be brief.

We were requested to talk about configuration risk management programs and tools. It's going to be a two part presentation. I'll talk in general and give an overview and then we have Jay Phelps, whose the Operations Manager from South Texas will provide a briefing on what they're doing down in South Texas now, they plan to implement. I'll defer most of my time to Jay because I think a picture is usually worth a thousand words, and he's got some good pictures.

In general, industry configuration risk programs have been around a long time. They are mature. They are effective at controlling risk, configuration risk in your normal operational conditions. They have been around and are an integral part of the industry's implementation in meeting the current regulatory requirements, particular Section (a)(4) of the maintenance rule.

Those programs have matured over the past decade and a half or so, and the tools that the

industry used to implement the requirements have matured along with them.

CHAIRMAN APOSTOLAKIS: Excuse me.

MR. HESS: Yes?

CHAIRMAN APOSTOLAKIS: Just a point of clarification. Do I really need the CRM program for the maintenance rule? I don't think so, do you?

MR. HESS: For (a)(4) implementation.

CHAIRMAN APOSTOLAKIS: Find me what (a)(4) is?

MR. HESS: That's essentially you effectively control risk --

CHAIRMAN APOSTOLAKIS: Set in the goals?

MR. HESS: No, no, no.

MEMBER SHACK: The applicable components are the service --

MR. GRANTOM: This is Rick Grantom, South Texas

Maintenance rule (a)(4) of assessing the cumulative effects of equipment out of service from risk.

CHAIRMAN APOSTOLAKIS: So I need the PRA?

MR. GRANTOM: No, not necessarily. The industry guidance does allow other quantitative approaches to be able to assess that.

CHAIRMAN APOSTOLAKIS: But I don't need these particular CRM configuration risk management tools, do I, for that?

MR. GRANTOM: You don't absolutely have to be required by it, but if you want to be more technically correct, you will use a PRA with a CRM.

CHAIRMAN APOSTOLAKIS: Heaven forbid I be allowed to do that.

No, I'm a little surprised by the statement you know, that plant CRM programs are mature. Throughout the industry are they mature really?

MR. HESS: Yes. And along those lines, it's a very focused and important industry function. All plants have configuration risk management programs. Some are more aggressive in terms of the amount of online maintenance and the degree to which they do take systems out of service at power and do maintenance and the like. But they all have formal programs to manage it. Basically all use the PRAs that they have in place to assess risk during those conditions.

CRM programs do augment the PRA type of evaluations with additional defense-in-depth evaluations throughout power configuration risk

management.

There is an annual industry forum that we've done for the past I think six years that brings up issues and helps further development of methods and tools.

And, by the way, there is significant amount of industry and Staff interaction at that forum. Typically, as long as you're not operating in a continuing resolution, there's a number of NRC staff that come to the forum and the interchange between industry and staff is mutually beneficial. And I know folks on the PRA Staff actually look forward to coming down. Plus, Florida in January is not a bad excuse.

But, in fact, the programs and tools are mature. And via the EPRI research and Staff interaction with EPRI and industry and the forum we continue to advance the technologies and the capabilities.

MEMBER BONACA: But I hear that some licensees do not use really risk information. They do evaluations, et cetera?

MR. BRADLEY: Can I clarify that?

MR. HESS: Yes.

MR. BRADLEY: There's actually two regulatory drivers for CRM now, even before 4B. One

is (a)(4) of the maintenance rule and the other is plants that have done AOT extensions using Reg. Guide 1.177 have a CRMP requirement as part of that. And that's why we've been doing this for a number of years.

In 1995 the original maintenance rule had (a)(3), which was a recommendation to have this. It was changed to a requirement in 2000 with the promulgation of (a)(4).

While our guidance allows plants to use non-quantitative methods, all plants use PRA informed methods for (a)(4).

4B is an extension of the existing (a)(4) methods that everyone's using. The 4B imposes a lot more rigor on the elements of those methods. But as Steve says, all plants have got a lot of experience using these methods already.

MR. HESS: Okay. Thank you, Biff.

And I think the three sub-bullets there on the bottom are very important benefits that plants, regardless if you would do 4B or not, have achieved and obtained from their configuration risk management programs. And as Biff said, for certain things in (a)(4), things like compensatory risk management actions and things like that are requirements.

Specifically within the implementation of 4B the implementation guidance is very specific requirements, of which these are just very high level groupings of what are there for the plant configuration risk management program and tools, particularly ensure that your CRM program and tools are faithful reproduction of the PRA model. And that's a bigger concern and issue for those people who use CRM tools that are on demand type PRA calculation engines as opposed to the approach that, for example, South Texas has where it's a direct just static database of the PRA results.

There are specific quality assurance and quality control requirements on the CRM programs and tools. And there are specific configuration control requirements both on the front end in terms of ensuring the CRM tool and program is a faithful reproduction of the PRA and on the backend as you make changes to the facility that those get implemented and in an appropriate manner and in a timely manner.

My last slide is just a bit of a recasting of the first slide and the first two bullets. But in terms of the tools, there are basically four tools used within the industry. They fall into two categories. One is a presolved PRA type look up

databases, the RASCaL and the RICTCal approaches that South Texas are using fall into that category. A lot of the plants use the Sentinel tool, which is a presolved PRA type of tabular approach.

Also there is on demand configuration PRA solvers. Those are the EOOS and the safety monitor tools and it's probably roughly a third, a third, a third split between EOOS safety monitor and Sentinel right now.

All of those tools also provide provisions to do additional defense-in-depth type analysis to make sure the risk is sufficiently analyzed, and particularly for communicating to work week management and shift personnel provides a new characterization tool.

And with that, I'll let Jay talk about what--

MEMBER SHACK: Are they using these same tools now for their shutdown management or they still have other tools for that?

MR. HESS: Most people for shutdown management use the ORAM tool.

MEMBER SHACK: ORAM.

MR. HESS: There's a lot more work in approaching defense-in-depth as opposed to specific

PRA type modeling. And obviously there's an A&S standards committee working on a PRA standard. So we expect that that will evolve over the next few years. But even within that defense-in-depth is still going to be an important element of shutdown. And I'll go back to what Andy said, you know, specifically for 4B it's geared toward that power type AOC extensions.

MR. PHELPS: I'm Jay Phelps. I am one of the division managers for STP in the operations department and hold a senior reactor operators license on that facility, and have since 1991.

I'm going to talk to you a little bit about the South Texas Project's readiness to implement the risk-informed tech specs.

I want to thank you for the opportunity here for the vision that has come out of both the Committee, out of the NRR and as well as the ACRS' receptiveness to our discussions on this area.

Got just a few desired outcomes. Want to make sure that that's going to meet what your needs or what information you'd like out of me. We're going to just provide a brief overview of our online risk assessment tools. We'll talk a little bit about our risk-informed completion time calculator, those attributes and how that's applied at the South Texas

Project. And then we want to talk about the risk management tech spec implementation at the South Texas Project.

Is there anything else we're going to want to talk about or would that cover your needs? Okay. All right.

Currently with the risk-informed completion time calculator it's based on our existing configuration risk management tool. You may have heard the term RASCal. This calculation's been using. That's for the implementation of maintenance rule (a)(4). So we're for each plant configuration we're able to take a look at the actual risk associated with those configurations.

The other pat of it does meet the NEI 06-09 guidelines. We were fortunate as Andy and the team from the NRC came down to South Texas Project. You saw they did have some feedback for us. And actually we'll end up with a better risk management as a result of that audit that we had performed.

Steve mentioned South Texas uses presolved maintenance states. Currently there are about 20,000 of those that are identified. They've got core damage and larger other release are prequantified in there. And it's a user friendly interface developed in

cooperation with the users, primarily that's been our work control organization and our licensed operators. They've been intimately working with Drew Richards out of risk management program to make sure that the tool works for those in the control room that are going to have to implement this as we move along.

MEMBER ABDEL-KHALIK: Let me just repeat a question that I asked earlier.

MR. PHELPS: Yes.

MEMBER ABDEL-KHALIK: As a result of this work with 20,000 sort of pre-canned states, have you found any frontstops that are currently in tech specs to be inadequate.

MR. PHELPS: I'll let Rick answer that one for you.

MR. GRANTOM: This is Rick Grantom.

No, we haven't.

MEMBER ABDEL-KHALIK: Okay. Has it been logical in the long term to replace all mechanistically based frontstops with results of these risk based assessments?

MR. GRANTOM: I can help with that, too, a little bit. But I think it really kind of comes down to a strategy at this point in time. We have already in the past extended some of our allowed

outage times, like diesel generators. With RITS 4B, you know, the consequences of an administrative shutdown due to a frontstop has been reduced. However, we may find it appropriate in the future here to take a look at some of the very short type of frontstops that we may have, the ones that are on the order of hours and maybe determine if those might should be extended out, the frontstops of those be extended out. But that's work that's yet to be done that we've not really evaluated right now. I mean, right now we have this before us and we're working on this, but it may lead eventually to something like that for things that have really short allowed outage time.

MEMBER ABDEL-KHALIK: I was just looking for conceptual consistency and if we're using this process, you know, why not use the same process to establish a much more defensible set of frontstops?

MR. GRANTOM: I take that as a very good comment, and I will use it as the basis as I go forward with my licensing people to in fact to be able to push this argument. Because I've had this argument before as to why do we have to do anything within an hour? I mean, what is so magic about an hour?

MEMBER ABDEL-KHALIK: If I may? Staff objected to that position before. They said that once

you had the 4B you didn't need (a)(4). They discouraged (a)(4)

MR. HOWE: This is Andrew Howe.

To clarify what I think I said, which is we wouldn't anticipate a licensee coming in and asking for a 14 day OT when he already had 4B. But if he had some very short times, he may want additional, maybe 12 hours instead of one to give him the time to implement the 4B process. That's what we would entertain.

We can't say we wouldn't entertain those things, because obviously licensees can submit what they wish. But once we've gone through the process of granting a 4B license then we would think we would think they pretty much got the flexibility they need.

MR. HEAD: This is Scott Head of South Texas.

Let me state that is the position. We view this to happen rarely enough that for our resources and NRC resources to go back through and change all those frontstops, that that's not in the benefit of either STP, NRC or the industry. It would be much better to go and look at some other ones that are either not in risk managed tech specs and take those from one hour to 12 hours or something like

that; that would be much more of a significant benefit.

MEMBER ABDEL-KHALIK: Well, I fully understand if this process involves the use of a lot of resources that you can direct somewhere else, but at the same time if during this process you can identify inadequate frontstops, then that would be critical to know.

MR. HEAD: Absolutely. We would agree with that. But right now for the vast majority of the work weeks and the work that we do, the frontstops are adequate. It's on those occasions, like in December we had two enforcement discretion that we were granted by the NRC. Risk managed tech specs would be how we would have addressed those.

MEMBER ABDEL-KHALIK: But how would you know that the current frontstops are adequate if you have not gone through the process of systematically evaluating them.

MR. HEAD: Because we do it on a weekly basis. We see the risk of each of these systems taken out on a weekly basis and we understand -- we see the risk impact on a weekly basis. And they've never come close to challenging the frontstops or the risk limits we have here.

MR. HOWE: This is Andrew Howe again with DRA.

My slides were necessarily brief, but let me be a little more elaborate.

One of the things that we've identified in the SE is a requirement to be submitted is an evaluation of the tech specs you're proposing to apply risk-informed tech specs to and to tell us what the typical risk-informed completion times would be. So if you had an example where the frontstop should be more restrictive, if you will, I mean that would be immediately apparent to us as reviewers and we would have to question whether 4B was appropriate for that tech spec given that the frontstop was already nonconservative. So that is being looked at in the context of 4B license applications.

Thank you.

MR. TJADER: This is Bob Tjader.

And South Texas provided that information, too, in a tabular format addressing each and every system that 4B is applying to and what would conceivably the AOT be extended to.

MR. PHELPS: Steven, if you'd go to the next slide, please.

Did we answer your question?

MR. HEAD: I agree with all that. I don't think it really addresses Said's question. Because you're not submitting for those that you're not asking for the 4B to be applied to.

MR. PHELPS: Right.

MEMBER ABDEL-KHALIK: So you really don't know?

MR. HESS: Well, if I may hazard just, I guess, more of an opinion than anything. Most of the tech specs that were provided and developed and even the standard tech specs that were approved under the ITS program were done with quite a bit of engineering analysis and conservatism in terms of the decision making setters. We don't reasonably expect that we would find a lot of instances, if any, of what you're questioning.

Theoretically it's possible, but I think, again, with a qualitative high degree of confidence we can say based on the analyses done that set in 4B space is the frontstop is a conservative time frame that does not have any significant risk impact. So the expectation is we wouldn't find very many of them, if we find any. And South Texas and other plants' experiences I think are very similar that the configuration would be very, very rare where an

existing frontstop would be unacceptable.

MR. GRANTOM: This is Rick Grantom.

I'd like to add a little bit more to what you're talking about.

When you look at the entire technical specification scope there is some technical specifications that are amenable to this type of evaluation and there are some that certainly aren't. Some that are associated with safety limits and set points are clearly out of scope. Things that are associated with core design, core limits those kinds are out.

But I'll go back to again a sense of what I said before. We have done a systematic look at every frontstop that could potentially -- potentially be modeled in a PRA. We have selected this scope as a whole plant pilot, which is a pretty extensive scope here. But I do feel that in the future this could be an area that we could look at to find out are there overly restrictive allowed outage times, and I'm talking tech spec items that may be on the order of hours for some punitive type of LCO action, you know to shutdown and those types of things.

MEMBER BONACA: But that, I expect that you find those. Not the opposite. I mean all tech

specs I know that are very conservative.

MR. GRANTOM: But I'll tell you part of the reason why that doesn't necessarily happen is because of the structure of tech specs right now. They're all done on single systems and single trains or channels within systems. You find the information where the LCO may not necessarily be so restrictive when you start looking at configuration risks and combinations of things and trains for which current tech spec methodology clearly can't do.

MR. BRADLEY: Yes. If I could add one more thing. That's one of the reasons that (a)(4) is a requirement today is to facilitate the risk management of tech spec. So you have (a)(4) for all plants today whether you implement 4B or not you're required to assess the risk of those configurations. And using the same metrics we're using here.

So I think someone said earlier you would know if you're doing this. Well we've been implementing 4B or (a)(4) for seven years now and there's a considerable experience that demonstrates that.

MR. GRANTOM: Right. Even in the maintenance rule if you see -- I mean, part of the reason that we're sensitized, and this is one of the

good things that happened about using risk approaches. For example, our functional equipment, we do our maintenance by functional equipment groups. During the early days when we first started risk profiling, we would challenge our threshold, the 1E minus 6 threshold quite often. And as we got to examining that it really just came down to what components were included in specific functional equipment groups. And they did some shuffling around of that and brought the risk down quite considerably where we rarely challenge or even come close to that 1E minus six threshold. And that was strictly from a scheduling basis. So we were able to see that type of thing.

Once you can visualize these things, it does drive in a sense improvement.

Now some of the other areas that you may be addressing are areas where there's not normally online maintenance performed on these components. And there, you know, we are possibly in a situation where I would tend to think that it'll be more the case that I talked about that we'll find that the LCO was too restrictive than what it is, rather than the case where we find for a single train or a single channel of a single system level function that the LCO is not adequate in that regard. Now, that's a personal

opinion there but based on our experience that we've had, I've not ever seen that.

So I would probably just say that this is an area, you can call it phase 2 or call it something else, but it's certainly an area that we haven't started to get into yet when we're trying to refine tech specs.

I hope that helped to answer part of the question.

MR. TJADER: If I could just say two things.

Number one, that was a question that came up very early on in the process. You know, well are there any frontstops that are currently nonconservative. And to be quite frank about it, I don't think we've found any at all, you know, that came up in the standard specs or anything like that where we think that we're nonconservative on just that single system basis. And I think in the application, as Scott said, in the daily application of Initiative 4B it would certainly come to the fore if there were a nonconservative frontstop. It would be readily apparent. And then I think then that it would become incumbent upon the plant and I think they would do the right thing and change that.

I think there's another aspect of your question, and that was raised too earlier in the process, and that was why not just go to a 4B process period and do away with frontstops? And conceptually that can be done, but practically it poses problems. And some of those problems are what if you find that you have a degradation in the tool itself, what then process do you have to cope with that on an immediate online basis type thing.

And some of those things can be addressed, but they are a phase in the future that can be addressed.

MR. PHELPS: All right. Does that answer the question? Come close? A good dialogue on that.

Okay. Moving on to just application. It's going to primarily be used by the operations staff. They'll be handling any emergent issues that come up. We're going to have a planned work week that our maintenance planners come in. They're figure out what sequence of equipment to remove from service that's going to result in the lowest risk and allow the work to be completed. Operations will have that loaded in and any changes in that plant configuration as equipment comes back to service to where it's operable again, or if some other piece of equipment is

necessary to take out, the tool that I'll show you in a moment is what is going to be used to do that.

Like I said, we use the look up table so we got a risk management group that if it's a nonquantified configuration, something we haven't looked at before, we've made an easy tool for the operators to be able to contact that group, show them exactly what that configuration is, and then allow them to come out and quantify that, put that into the program so that the numbers and the allowed outage time will easily make very clear to the operations staff.

Real quick, this is really the first screen the operator will come to when he's in the control room. This is going to allow him to enter whatever the inoperable systems. We kind of preprogrammed a few components in there; safety injection, common alpha, chilled water alpha, essentially cooling water alpha train. And then we added a new bug in here. Said, okay, what happens if the bravo diesel generator was made inoperable? So the operator enters all this in there. He can time stamp it with what comes in. He simply comes up to the RICTCal button, hits that. And as that's going on, these calculations are taking place, and this is the

screen that comes up. I really want to focus on a couple of areas there. And we're working on the words over here, so we'll try to explain them.

Backstop, this is really looking at what is the completion time based on that plant configuration.

The words that are up here now say "regulatory." That would be the 30 day backstop limit, if you will.

The calculated value is going to say at what threshold, at what point do we pause the E to the minus five for what that risk-informed completion time. The one labeled CP down here is going to actually plug in the value that's the most limiting of those two values. That's what the operator will now have for his allowed outage time. That's the time that equipment has to return to service or be shutdown for what we're doing there.

You can see there's lots of other values and stuff that's really the focus area. It tells you what the configuration is. It's within the PRA. And what the completion time is for the operator.

MEMBER SHACK: Doesn't he need to know, why isn't this RMAT thing kind of highlighted over there, too?

MR. PHELPS: Well, it's not highlighted there, but you're right that is one of the other key attributes of the risk-informed tech specs. That prior to exceeding that E to the minus six, or if you planned on doing that, the risk management actions have to be in place identified and documented showing what you're going to do to support that risk-informed completion time.

Just one more quick --

MR. HEAD: Jay, could you just clarify for everybody?

This is Scott Head.

The top, I guess, four were the planned activities for the week.

MR. PHELPS: That is correct.

MR. HEAD: And when essential cooling water goes out, the diesel goes out also. And so breaking the diesel we're in an unplanned configuration. And it is sort of interesting to see that basically almost seven hours into that we need to have some risk management actions now because we're on a much steeper slope now than we would have been before.

MR. PHELPS: Yes.

MR. HEAD: And so everything is available

to us, the operators, to make the decisions.

MR. PHELPS: That's correct.

All right, thank you, Scott.

MEMBER SHACK: A huge difference between your safety limit and your RMAT limit?

MR. HEAD: Absolutely. And it's meant to be that way.

MR. PHELPS: And you can see, I mean we even have what the hourly rate is based on the durations for what that change in core damage probability is as time's clicking out.

Okay. Go one more. I'll just give you a quick example. Adding on to that, now we also had an additional problem crop up that showed the qualified display processing system bravo was made inoperable in there. You can see it just comes up just backgrounded in red. That indicates, you can tell by that the key on the bottom, that that's a nonquantified state.

To make it simple, all we have to do is you notice notify risk management admin if there's nonquantified states. The operator just clicks that button. An email goes out to all the individuals that are in Rick's group that have the ability to come on out or sit at their home computer to prequalify that. It'll show up all of this information on the

electronic mail system that goes out to them. And he can sit there at home with the actual whatever tool they use to come up with that quantified state. Program that in there so that it'll go ahead and fill in what the calculated, what the completion times. And that's the expectation, we do that within 12 hours.

I just want to point to you the LERF. The values aren't in there. We simply haven't loaded that information in yet. That will be a part of this tool so that that will be identified so that you know whether you're working off of a LERF restrictive value or whether you're working off of a core damage probability value.

So those are the tools we've implemented for the South Texas Project to implement this at this time. And, like I said, we've got some hands-on training with that tool again during this outage where someone from Rick's group will be working with all of our senior reactor operators working through the various procedures that we have in place that are ready to go.

And the bottom line is, is when this is approved and we get the SE resulting from the South Texas Project application, South Texas Project is

ready to implement this new process and appreciate the opportunity to discuss that.

Any more questions for me?

MEMBER MAYNARD: For South Texas, it sounds like the way you're doing it, the operators are the ones who is going to plug in the numbers and determine what the completion times, allowed outage time are. It's a final say as with the operators there?

MR. PHELPS: Yes, sir. That is correct.

MEMBER MAYNARD: And you only have to go to the risk management group or if you have unqualified number?

MR. PHELPS: That is correct. Yes. Anything that's already presolved and basically any configuration we have found ourselves in up to this time, Rick and them have turned that into one of those look up values on that table. So it would be someplace we hadn't been before, and they'd have to out there and solve that one so that they could go into the table, recognize that current plant configuration to calculate whatever the risk-informed completion time would be for that specific configuration.

MR. HESS: And if I may talk about for CRM

tools in general for the industry, the paradigm and the way it's done at South Texas it standard pretty much across the industry. Work week managers and on shift supervisors all have training, knowledge and capability of how to run the order. It's EO, Sentinel, safety monitor or in your case RASCaL and RICTCal. Those tools are robust and user friendly and training is provided to those people as part of their job function.

MEMBER MAYNARD: And I have no problem with the operators doing it. My question really gets more into a jurisdictional and whose from a license standpoint, who is the one making the final decision and doing the work. And that's why I'm asking. Not as to any other reason.

MR. PHELPS: No doubt. The on shift SRO is going to make the determination of inoperability and when that component can be returned to an operable status.

MR. GRANTOM: Which you would expect with tech specs.

MR. HESS: Having been an ex-SRO that is always function of the person who holds the operating license.

MEMBER ABDEL-KHALIK: I'm just trying to

understand this process. You're going to go through and do this and you come up with a date. And presumably this date is going to go on a work order so that whoever is doing the repair work knows what the deadline for completion of this task should be?

MR. PHELPS: It's actually tracked in the control room log. But if a new work order does come up, we do have a place just in our process where we do stamp the required return to service time for those individuals on --

MEMBER ABDEL-KHALIK: Now, let's say something else crops up and you have a work order out there with that date stamped on it, how does that date change based on the new result?

MR. PHELPS: Well, physically we would not go out and grab that work order and change that. That would be communicated through the various management meetings that we have on what the required return to service dates are. They're published in our normal daily work status meetings, if you will, for the normal management team. Because those dates can change, you're right. They're different than what current tech specs on frontstops, but they pretty much stay set, if they will. But if that changes due to something else breaking in the interim, that just

communicated it through the station to the responsible manager in that organization to say now you only have two days to complete that --

MEMBER ABDEL-KHALIK: And how is that documented? How is that documented for the people who are actually doing the work?

MR. PHELPS: Documented for people actually doing the work? It's just contained in the station log. We utilize a process called the operability assessment systems, that's the official record for tech spec tacking at the South Texas Project where that information is documented. As far as an individual work group's work package that's maybe working on some component, it is not documented on their work package.

MEMBER MAYNARD: Well, first of all, it really isn't any different than the process without this.

MR. PHELPS: Right.

MEMBER MAYNARD: Because you can have the same thing occur under the current tech spec --

MR. PHELPS: Correct.

MEMBER MAYNARD: And typically anything that has a tech spec system out of service, you have somebody specifically assigned and following that. And

the control room is following up on that, too. So not all plants are going to stamp anything on the document.

MR. PHELPS: Correct.

MEMBER MAYNARD: The workers, and in fact you don't always not necessarily want them working under a time pressure. They're to do a job. You have other people managing the project that have to be minding the --

MEMBER ABDEL-KHALIK: Yes. But my concern is, you know, if there's a piece of paper out there stamped that says this work has to be done by 3/27/07 and then suddenly something else happens that requires the work to be done earlier than that, there is a document out there that says it has to be done by 3/27/

MR. HEAD: This is Scott Head.

As Jay said, our process is the communications process, even if you want to go down to something we call a 30 minute rule on informing individuals of changes in the station, that information will quickly get to the management structure or maintenance and all the way out to the field to the people that say, oh boy the way, you know we're under a new situation now. But I have to agree,

that's not at that point in time then to transfer schedule pressure, and is one of the aspects of this that's I think appropriate is that we have a new completion time. The station is area of it. With respect to the people doing the work, it's still almost irrelevant. They're going to get the work done based on the schedule that they have that has been transferred to them.

So the processes are set up to deal with this within the station. And that piece of paper that was out there before won't impact that.

MEMBER MAYNARD: Well, people who have to know it are the operators in the control room. Because they're the ones who is going to have to take action if it's not returned to service within that time.

MR. HESS: If I may, and this allows me to actually reemphasize a point I made that Dr. Apostolakis challenged me on, is our CRM programs mature.

All plants' CRM programs -- plants have processes and procedures in place with appropriate personnel, typically the work week manager. When an issue like this comes up, whether you're a 4B plant or just regular now with maintenance rule that this is a

normal course of business and it gets handled within that framework of the configuration risk management program. And, you know, in even broader context. You know if there are issues that come up that do not get addressed well during the week, there are formal debriefs and look backs and lessons learned that go in the corrective action program to address these. And in instances where we don't address them maybe in an ideal manner, those lessons get learned and allow for continual improvement.

So this is standard fare for plant configuration risk management programs.

MEMBER MAYNARD: I guarantee everyone knows if you're getting close to a completion time, not that this would be a deterrent.

MR. PHELPS: Station processes and procedures are pretty robust about communicating the needs for return to service equipment even as plant configuration changes --

MEMBER MAYNARD: And doing it without putting pressure on the workers to rush.

MR. PHELPS: Right.

CHAIRMAN APOSTOLAKIS: Any other comments or questions? Yes?

MR. EDAWAR: This is Souhair Edawar. I'm

from Palaveri Incorporated.

Since you work from presolved cases, if you have to encounter something that is not in there among the presolved cases, do you feel 12 hours is adequate for you during a night shift to bring a PRA engineer and solve the specific case for you?

MR. PHELPS: Yes, I would say we were pretty intimately involved with the actual development of that guidance. And in our case we feel very confident that 12 hours we can easily accomplish that. And the other side is that if you can't do it within that 12 hours, the right thing is probably to shut the unit down if you can't get --

MR. EDAWAR: Well, I mean in the a night shift where you have to bring somebody from home and do it, PRAs are usually -- I feel that's not enough--

MR. GRANTOM: Well, this Rick Grantom.

We have a duty risk engineer on duty 24 hours a day that rotates through my staff. And they are on call. And if they get the call to do this, we've given them the capability to quantify an unquantified maintenance state either at their home or at the site. But if it's at their home, they've got the ability to update the maintenance state database remotely and transmit that back to the control room

operator all under software quality assurance programs to do this. And, in fact, they can do it like within an hour in many cases. A couple of hours. I mean usually it's just the amount of time to get them on the phone. So we've done this.

And we have been doing this for many years already to do unquanified maintenance states and turn these things around within hours. So we, in fact, have been doing it for ten years already.

MEMBER MAYNARD: I have one other question for South Texas since you're the first one going through this. Staff identified that there were a couple of the tech specs that you had identified that you took out of the process as a result of the audit. And I'd just like to have South Texas' perspective on whether they think the process is being too stringent or whether there are things that need to be taken out?

MR. GRANTOM: No, absolutely not. We believe that interaction was appropriate. And what it's, I guess, given us is a strategy moment is that to move forward in some of those that was taken out, we're going to have to put them in the model more effectively. And so when I call on site, and I've talked to our senior management about, is phase 2 that if we want that stuff, those components to be embedded

in risk management tech specs, then we're going to have to go back and more effectively model them in the PRA.

Now, in many cases they're not there because they don't have much of a risk impact. I mean they're not there for a logical reason, but for us to want to be able to take advantage of this, putting it back in is the logical place to go. So that is what we're calling phase 2. Once we get past this, we might envision here a couple of years from now we come in with another submittal where we have put more systems back in. But to do that they'll have to be modeled and they'll have to be able to meet NRC's expectations in those areas.

CHAIRMAN APOSTOLAKIS: Any other comments?

Well, thank you very much, gentlemen. Appreciate your coming here.

There are two things we need to do. One is to give advice to the Staff as to what they should present to the full Committee. I've drafted here something, and then maybe the members can add or subtract.

We have an hour and a half in April. We also have several members who are new to the Committee. So it would be nice for you to give an

overview of what 4B is all about, a little more detail than today, in other words.

I like that example with the actual curve that is in the document that shows, you know, how assuming one component is down the risk starts going up and then there is an emergent condition, it goes up. That goes a long way towards explaining what this whole business of backstops and risk-information completion time. That's figure 3-3 or something similar.

You have used in the past.

MR. TJADER: Yes. I know what you're talking about.

CHAIRMAN APOSTOLAKIS: But I think it's worth repeating.

I would like to see included this issue of uncertainties, especially what Mr. Grantom mentioned, the specific examples that you found. Because this is language that most members understand what kind of uncertainty we're talking about and how it was handled.

I would like to see, you know, the issue of how Regulatory Guide 1.174 enters into this and the delta CDF/delta LERF. And maybe change also as appropriate the SER.

And also, Mr. Maynard's comment as to what conclusions one would reach by comparing with the regulatory guide so we have the mechanics of it and plus the conclusion.

And my understanding is that what you are asking the ACRS to do is to write a letter endorsing your approval of NEI 06-09, that's really what it is?

MR. TJADER: Yes, sir.

CHAIRMAN APOSTOLAKIS: Now is there anything else that the members would like to add to their presentation?

MEMBER MAYNARD: Well, one other thing I would like to see in there, just a brief thing, but this whole presentation kind of comes across as just a way to have a system out of service longer. One of the real benefits also is to the NRC and the regulatory because of the way things that are handled now, you end up with a problem that would otherwise shut you down. You have to go into enforcement discretion. You're talking about late night calls, perhaps, and the NRC being put in a position of having to make a decision for enforcement discretion.

This kind of eliminates that process for these things.

CHAIRMAN APOSTOLAKIS: Sure. Yes, the

benefits from these --

MEMBER MAYNARD: The benefits, yes.

CHAIRMAN APOSTOLAKIS: -- both to the industry and to the agency.

I don't know, are you gentlemen planning to come or is it only the Staff.

MR. TJADER: Yes, we'll be here.

CHAIRMAN APOSTOLAKIS: You'll be here. Okay.

MR. HOWE: They don't trust us to be here alone.

CHAIRMAN APOSTOLAKIS: They also like the ACRS.

MR. GRANTOM: Jay Phelps will be on night shift. And Rick will be on night shift, but he might be here. We'll see.

CHAIRMAN APOSTOLAKIS: You think your issue should be addressed at the full Committee meeting of nonstops and all that or are you satisfied?

MEMBER ABDEL-KHALIK: No, I think conceptually that's fine.

CHAIRMAN APOSTOLAKIS: You are satisfied?

MEMBER ABDEL-KHALIK: Right.

CHAIRMAN APOSTOLAKIS: Bill or Mario?

MEMBER BONACA: Well, I think the

presentations were very clear.

CHAIRMAN APOSTOLAKIS: Yes.

MEMBER BONACA: I mean, with a few clarifications.

CHAIRMAN APOSTOLAKIS: Yes.

MEMBER BONACA: Plus they were pretty condensed anyway, so that it will fit well in a hour and half.

CHAIRMAN APOSTOLAKIS: Okay. Great.

Now, can we go around the table and have the members give me some advice as to what to put in the letter or should I just draft a letter and have you slobber it?

MEMBER BONACA: I think, you know I mean I am very positively impressed by the progress made in this area.

CHAIRMAN APOSTOLAKIS: Okay.

MEMBER BONACA: I think there are great benefits to the use of this tech specs, as I was saying. And it is really a coherent step with everything we have done in risk-informed in the regulation. I think that's it.

CHAIRMAN APOSTOLAKIS: So if we approve this, you will not come to the ACRS again requesting another else? 4B is done, right, if we say fine and

the Commission says fine?

MR. TJADER: I don't envision us needing to come back again. The reason that we want this is validation.

There are, perhaps you've encountered it in what you do for a living, but I know that on the Staff we encounter it frequently, that there's a lot of skeptics. Okay. And I think that it would be beneficial to have the ACRS weigh in positively, obviously not negatively, on this. And I think it would be helpful in us being able to justify going forth on this. Not that we aren't doing that already, not that we haven't fought a lot of internal battles and been successful in it.

Andrew just brought up thing that perhaps -- I don't know I have to think it -- you can think about it.

One of the things that we currently I've come to grips with and I think that we've satisfied the Staff that it's adequately addressed, and that is that applying this to systems where there's a loss of function. And conceptually the way it works is that-- and I feel comfortable with the way it works. And I think the industry does. But I know that ont he Staff there's some discomfort to applying this in general.

The way it conceptually works in tech specs is that if there is a loss of function, if there is an inoperability which causes two trains to go inoperable and you've lost function, you cannot apply a risk-informed completion time. An we agree with that.

Where the controversy comes in is where you have inoperabilities of both trains on a two train plan. Okay. And then you retain some of its capability in its safety function area. And then being able to, when you're to apply that, that capability that is reflected in the PRA to extend the completion time we feel is a perfectly justifiably thing to do. But we find great resistance from the Staff in doing that.

And I think after we explain it a little bit, they become more comfortable with it. But conceptually it's something that has to be overcome.

CHAIRMAN APOSTOLAKIS: Would you please include that in your presentation?

MR. TJADER: Next time?

CHAIRMAN APOSTOLAKIS: This issue. Yes.

MEMBER MAYNARD: It goes along with what was mentioned about the no add and the benefit.

CHAIRMAN APOSTOLAKIS: But make sure that you include it.

So the issue is you have a two train system.

MR. HOWE: But both trains are declared inoperable but you think there is still --

CHAIRMAN APOSTOLAKIS: -- function --

MR. TJADER: Well, you don't necessarily. Just because a train is declared inoperable, it actually necessarily sometimes need to effect the function of it why it's inoperable.

CHAIRMAN APOSTOLAKIS: I see.

MR. TJADER: And plus if you have backup capabilities that provide function that are not reflected in the specs, then it could cause you to take that shutdown action when there still is some functional capability remaining.

MR. HOWE: I think where the real issue comes in for the other staffers is -- and I'll say these words -- don't take any offense licensees, but trusting licensees to make the decision that something still has capability when it's declared inoperable. The mind set, which is perfectly legitimate, is once you declare something inoperable you're supposed to shut the plant down as you've lost both trains.

MEMBER BONACA: Often times it's purely the degree or it's purely -- there is cases where

you're sure of functionality.

MR. HOWE: Right.

MEMBER BONACA: The question is the degree of assurance that you have functionality. That's the big question.

MR. HOWE: And it hard to write a document that really nails that down specifically. I think we've done a pretty good job.

MR. TJADER: Yes. The document is written very conservatively. The problem is always there's shades of gray. You know, the document is written decisively that if you do not -- if you're uncertain about the functionality, you take the conservative action.

CHAIRMAN APOSTOLAKIS: I remember seeing something like that in the document. Tell me where it is, so I can go. Is it easy for you to tell me right away? That's in the SER?

MR. TJADER: There are two places. Functionality is addressed in the reg. guide in -- not the reg. guide, the NEI 06-09 area. It's stressed, for instance in the --

MEMBER MAYNARD: Page 5.

MR. TJADER: In section 231 paragraph 11. Okay. PRA functional assessment. And then we have in

the SE, we have -- now let me give you something else. What I said opening the presentation this morning is that the essence of our SE has not changed. What has changed is the wordsmithing to satisfy some of these concerns. And now is the time I guess -- I didn't know that I would need to, but here are -- this is the area in the SE which has been changed.

CHAIRMAN APOSTOLAKIS: Regarding this issue?

MR. TJADER: Regarding this issue.

CHAIRMAN APOSTOLAKIS: Okay.

MR. TJADER: This is where we've had to address that issue.

MR. HARRISON: I would suggest if we're going to actually present that topic, that we give it as an example so you can understand exactly through the example what's going on.

CHAIRMAN APOSTOLAKIS: Rephrase it anyway so the members will have an opportunity to first understand it.

MR. HARRISON: As a background.

CHAIRMAN APOSTOLAKIS: And second, comment on it.

MR. TJADER: I think when you read this, you'll see that really you compare it to what you've

given. And there aren't significant differences. But internally just these changes have involved days worth of discussion and argument, and compromise and so forth. So it may not seem like a lot, but this is an area which internally the Staff has voiced considerable concern.

CHAIRMAN APOSTOLAKIS: Okay. Very good. Thank you.

Any other comments from the members?

MEMBER MAYNARD: I believe it's a process that benefits safety, it benefits the NRC and I think it benefits the licensee. And I think overall it's a good process and a much better way of doing business than what was originally the way we did the tech spec. So I think overall it's the right thing to do.

I think from what I've heard and what I've seen that it has the right constraints in it and the right processes involved. So overall, I think it's something we should endorse.

MS. BANERJEE: I'm Maitri Banerjee. I'm ACRS staff.

I was wondering if you would like staff to talk about any items for inspection follow up like the resident inspections at the plant. I mean, they're going to be writing a TI inspection guidance, right?

MR. TJADER: I've prepared a draft inspection procedure. I think internally I'm somewhat behind, but Andrew and I have prepared a draft. I prepared it, he's edited it somewhat. We've given it to our inspection branch. I need to pursue and push it along so that when it hits South Texas that we have something in place for the residents.

But if you want, I can -- two weeks is a very short time to --

MS. BANERJEE: Not the whole guidance.

MR. TJADER: Just some words? I could put something in there.

MS. BANERJEE: Some important aspects that needs to be followed up or will be followed up or the guidance. Is that of any help?

MR. TJADER: Okay.

MEMBER MAYNARD: That would be helpful. Fine.

MR. TJADER: Just a few words.

MEMBER MAYNARD: Okay, as long as we don't get diluted so much --

MEMBER SHACK: Yes. I mean I'm a little worried here that we're going to cover the waterfront here. You know, an hour and a half -- especially for the new members that sort of need to go back to the

fundamentals of this.

CHAIRMAN APOSTOLAKIS: Yes.

MEMBER SHACK: Three hours of the hour and a half are already covered.

MEMBER MAYNARD: I think this may be something to be prepared if a question or something comes up.

MR. HEAD: This is Scott Head.

We can discuss. As we have briefed to the Region, we have briefed to the resident. We talked about it before. This is tech specs and so on their morning visit to the control room, they will know this has been implemented and they will be able to pursue it within their tech spec modules they already have available to them. And even their (a)(4) modules. So there's a lot of aspects that are already built into the program that would allow them to look and evaluate this.

So I recognize a TI could come out to help in that, but I mean this is something the residents can get engaged in immediately.

MR. TJADER: I can make it a backup slide to the next presentation.

CHAIRMAN APOSTOLAKIS: If necessary, yes.

MEMBER SHACK: Even, George, even your

1.174 issue I just look at as something that could get us going down the road for a long time. It's kind of a small piece of this.

CHAIRMAN APOSTOLAKIS: Oh, not quite. They're asking them to do it every 34 months as part of the --

MEMBER SHACK: But you didn't hear any objections from anybody.

CHAIRMAN APOSTOLAKIS: What do you mean?

MEMBER SHACK: Of doing it, you know.

CHAIRMAN APOSTOLAKIS: No. And I don't object either. It's just how it's done.

MEMBER SHACK: Well, as we try to explain this, I can just see this barreling out of control in the meeting.

CHAIRMAN APOSTOLAKIS: I'm Sub Chairman, you will be Chair --

MEMBER SHACK: Well, I'll be Chair. Right, the gavel will be handed.

MR. HOWE: Can I have a gavel, too?

CHAIRMAN APOSTOLAKIS: Are we okay?

MR. TJADER: Okay.

CHAIRMAN APOSTOLAKIS: So I guess it's favorable impression.

Okay.

MEMBER SHACK: If the South Texas PRA is just barely adequate for this purpose, I'm not sure for the rest of the world. But that's okay. It's one PRA at a time.

MR. TJADER: You have a point, unfortunately. We had a couple of pilots that needed to upgrade their PRAs. And due to related issues, they had to withdraw.

CHAIRMAN APOSTOLAKIS: Okay. Thank you very much. This is very informative. And we'll see you in a couple of weeks.

(Whereupon, at 11:38 a.m. the Subcommittee meeting was adjourned.)

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