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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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482nd MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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THURSDAY,

MAY 10, 2001

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ROCKVILLE, MARYLAND

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

PRESENT:

GEORGE E. APOSTOLAKIS	Chairman
MARIO V. BONACA	Vice Chairman
F. PETER FORD	Member
THOMAS S. KRESS	Member-at-Large
GRAHAM M. LEITCH	Member
DANA A. POWERS	Member
WILLIAM J. SHACK	Member
JOHN D. SIEBER	Member

PRESENT:

ROBERT E. UHRIG	Member
GRAHAM B. WALLIS	Member

STAFF PRESENT:

JOHN T. LARKINS	Executive Director ACRS/ACNW
SAM DURAISWAMY	ACRS
ROB ELLIOTT	ACRS
CAROL A. HARRIS	ACRS/ACNW
HOWARD J. LARSON	ACNW
JAMES E. LYONS	Associate Director for Technical Support
MICHAEL T. MARKLEY	ACRS

ALSO PRESENT:

RAJ AULUCK	NRR
PATRICK BARANOWSKY	NRR
TOM BOYCE	NRR
BENNETT BRADY	RES
J.E. CARRASCO	NRR
BOB CHRISTIE	Performance Technology
EUGENE COBEY	NRR
JIM DAVIS	NRR
BARRY ELLIOT	NRR/DE/EMCB

ALSO PRESENT:

JOHN FAIR	NRR
HOSSEIN G. HAMZEHEE	NRR
STEVE HOFFMAN	NRR
TOM HOUGHTON	NEI
RANDY HUTCHINSON	Entergy Nuclear
PT KUO	NRR
STEVEN E. MAYS	NRR
HO NIGH	OCM/RAM
DUC NGUYEN	NRR
ROBERT PRATO	NRR
DEANN RALEIGH	LIS, Scientech
MARK RINCKEL	Framatome-ANP
MARK SATORIUS	NRR
PAUL SHEMANSKI	NRR
JENNY WEIL	McGraw-Hill
PETER WILSON	NRR
STEVEN WEST	NRR
TOM WOLF	RES
GARRY G. YOUNG	Entergy Services
BOB YOUNGBLOOD	ISL

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(8:30 a.m.)

CHAIRMAN APOSTOLAKIS: The meeting will now come to order. This is the first day of the 482nd meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the Committee will consider the following: Final review of the license renewal application for Arkansas Nuclear One, Unit 1, risk-based performance indicators, discussion of South Texas Project Nuclear Operating Company exemption request, and proposed ACRS reports.

In addition, the Committee members will attend the Commission meeting on the Office of Nuclear Regulatory Research Programs and Performance, which will be held at the Commissioners' Conference Room between 10:30 and 12:30 this morning.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Dr. John T. Larkins is a Designated Federal Official for the initial portion of this meeting. We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions.

A transcript of portions of the meeting is being kept, and it is requested that the speakers use

one of the microphones, identify themselves, and speak with sufficient clarity and volume so that they can be readily heard.

I will begin with some items of current interest. I'm very pleased to announce that the Board of Directors of the American Nuclear Society has elected Dr. Tom Kress, a Fellow of the Society. This honor recognizes Tom's outstanding efforts in the area of nuclear health, safety, and regulation. It is certainly a well-deserved honor, and our Committee is fortunate to have members of this caliber.

(Applause.)

CHAIRMAN APOSTOLAKIS: Because of the unavailability of staff documents, Committee review of the South Texas Project exemption request and spent fuel pool accident risk of the Commission in plants, which was scheduled for this meeting, has been postponed to future meetings. As a result, there will be no Saturday meeting this month, and the meeting will be adjourned around 4 p.m. on Friday, May 11.

I hope the staff recognizes the impact on ACRS resources of dropping items from the ACRS meeting agenda at the last minute. The ACRS Executive Director has been discussing this concern with EDO.

I'd like to draw the members' attention to

the items of interest, the pink cover. The three speeches, or comments, by commissioners; comments by Commissioner Dicus at the Texas Women's University Honors Convocation on April 19 where she was honored as a distinguished alumna of the University; the opening statement of Chairman Meserve at the press conference that he held on April 26, and remarks, or a paper, that Commissioner Diaz gave at the meeting in Germany of the Internationale Lander Kommission Kertechnik on April 26.

Finally, a fourth item of interest is the testimony by Mr. Lochbaum of the Union of Concerned Scientists on Nuclear Power before the Clean Air, Wetlands, Private Property, and Nuclear Safety Subcommittee of the U.S. Senate Committee on Environment and Public Works.

And the first item on our agenda is the final review of the license renewal application for Arkansas Nuclear One, Unit 1. Dr. Bonaca is a member. Mario, it's yours.

DR. BONACA: Thank you, Mr. Chairman. Our Subcommittee on Plant License Renewal met with the applicant and the staff on February 22, 2001 to review the license renewal application. At the time, we noted two things: One, is that the application was

quite clear and easy to follow on the part of the members that facilitated that review. The second issue was that there was only a few open items remaining between the staff and the applicant to be closed.

Because of those two circumstances, we recommended to the Committee that we would not have an interim meeting, and therefore we did not have that. We are here now to discuss the review of the final SCR with open items closed. Therefore, this is really the final report regarding license renewal. And with that, I will let the staff and -- actually, I would like to let the staff, first of all, initiate a meeting.

MR. KUO: Thank you, Dr. Bonaca, and good morning to the Committee. My name is PT Kuo, the Chief of Engineering Section of the License Renewal & Standardization Branch. The staff is ready to report to the Commission its review of Arkansas Unit One license renewal application. The presentation will be made by Mr. Robert Prato this morning. He will first give you an overview of the project, followed by the applicant's presentation on its license renewal application. And then Mr. Prato will summarize the results of staff's detailed technical review.

I would like to just make one observation since Dr. Bonaca already mentioned that from this review I know of no open items left unresolved. And the remark I would like to mention is that this review is about eight months ahead of schedule. It's remarkable; it's very impressive. I also was told that Mr. Hutchinson, the Senior Vice President for Entergy Nuclear, would like to make a few remarks after I finish my remarks. And after Mr. Hutchinson's remarks, I will then turn the presentation to Mr. Prato.

MR. HUTCHINSON: I'm Randy Hutchinson, Senior Vice President for Entergy Nuclear. We're pleased to be here today and to be a part of this review of ANO Nuclear Unit One's license renewal process.

We, as you know, followed just behind the Oconee application, which is a sister plant, and we incorporated a number of lessons learned. In between incorporating those lessons learned from the Oconee process of what's been done in the industry and the guidance provided by the Nuclear Regulatory Commission in terms of license application format and that sort of thing, we're able to put together a license application, and as a result of that, one that had

very few open items, a substantially reduced number of requests for additional information.

So, to us, this was really a pretty pleasant experience. We found the license renewal process to be stable and predictable, and it worked very well for us. And Mr. Garry Young, the Project Manager for our ANO project, will be making our part of the presentation when we get to that. Thank you.

MR. KUO: And with that, Mr. Prato?

MR. PRATO: Good morning. I'm Bob Prato. I work in License Renewal Branch in NRR. Before I get into the overview, I'd like to inform the Commission that we used Oconee as a benchmark for our presentation, as we did for the Subcommittee. We did that for a number of reasons. First of all, Oconee and Arkansas Nuclear One are sister plants on the NSSS side. The other reason is they used the same topical reports that was used in the review for the Oconee license renewal application. And the third reason is, is that ANO incorporated a lot of the lessons learned from the Oconee application. All of the open items that Oconee had, most of them at least, were resolved in the application for ANO 1.

So as I go through my presentation, I'm going to be identifying some items. Those items are

the items that ANO 1 captured in their application without any concerns as there were for Oconee. It's not an intent to comment on Oconee's application. Oconee did a great job. They were the first one up at bat -- one of the first ones up at bat. And I just wanted you to know they took advantage of the lessons learned from the Oconee application.

To begin with the overview, the unit description for ANO 1 is ANO 1 is a two-unit site consisting of a Babcock and Wilcox Pressurized Water Reactor and a Combustion Engineering Pressurized Water Reactor. And it's located in Pope County in Central Arkansas on Lake Dardanelle.

On January 31, 2000, the applicant submitted a license renewal application for Arkansas Nuclear One, Unit 1, the 2,568 megawatt thermal Babcock and Wilcox Pressurized Water Reactor. Unit 1 construction began in 1968, and it went commercial in 1974. The current facility operating license expires in May of 2014. The facility is similar to Oconee in NSSS design.

ANO 1 site compared to the Oconee site, Oconee is a three-unit Babcock and Wilcox facility. It has a standby shutdown facility, which is unique to the industry, which ANO 1 does not have. And they use

the Kiwi Hydroelectric Dam as their emergency source of power. ANO 1 uses diesel generators as their emergency source of power, and they have an emergency cooling pond as an alternate source for the ultimate heat sink.

Comparing the two applications, Oconee's application was developed before the standard review plan was issued. Therefore, it was broken down basically into five sections. There was an introduction, a scoping, an aging effects section, an aging management review section, and a time-limited aging analysis section. The ANO 1 application is more consistent with the standard review plan in which they combine Section 3 and 4 of the Oconee, so there's only an introduction, scoping, aging management review, and time-limited aging analysis.

In addition, they added an Appendix C. And Appendix C are the aging effect tools. One of the concerns with the Oconee application was applying consistently the aging effects for the different components that were inside containment and outside containment. In the Appendix C, the tools that they used resolved that concern.

As far as the safety evaluation report, ANO 1 only had six open items. They included a sodium

hydroxide orifice, scoping question -- fire protection scoping question, FSAR supplement additional information needed in the FSAR supplement for, I believe it was, a total of 11 different items. There was some concern with the Medium-Voltage Buried Cable Aging Management Program; there was some concern with the Boraflex, and there was some concerns with the trending of the tendon pre-stress forces. We will get into all of those specifically as we go through the aging management review presentation.

At this time, I'm going to turn this over to Garry Young, of Entergy, who will cover the application.

MR. YOUNG: Thank you, Bob. My name is Gary Young, and I was the Project Manager for the ANO 1 license renewal application for Entergy.

The first thing I'd like to go over with you is on slide 4, which is what we call the document hierarchy for our application. The top item on this slide shows the actual application itself, which was the package that we submitted to the NRC for review. Below that you'll see a list of several documents here, which are what we call our on-site documentation that was a backup, or supporting documentation, that supported the statements that were made in the

application. And at the very bottom of that slide you'll see the basic breakdown of the different types of aging management reviews -- scoping and aging management reviews that were done.

We broke them into categories. We had the class 1 mechanical reviews, which were based on the B&W topical reports. These are the same reports that Oconee used in preparing their application. The second grouping is the non-class 1 mechanical. These are the systems that were not covered generically by the topical reports, and we had to review those on a site-specific basis. The third grouping is the structural aging management reviews. Those were based on some industry guidelines that were prepared by the B&W Owners Group. And then the next one is the electrical grouping, and these were based on Sandia aging management guideline documents that were made available to the industry. And those are the major categories.

In addition to that, we did a TLAA review, which was separate from the aging management reviews, although closely related. We also did an environmental review, which was part of the Part 51 review requirements for license renewal. And then we summarized in one document all of the aging management

programs that were identified in all of these various aging management review reports.

So, total, there were probably around 50 engineering reports, individual reports that were generated to support the application that was submitted to the NRC for review.

Okay. Then on the next slide, on page 5, I'd like to go into the -- I'm going to talk through each one of the areas of the application, a little quick summary on how we did the review that went -- the results that were documented in the application. And the first part of that is the scoping. And the scoping is based on the rule requirements that identify what is to be in scope for license renewal. We used the guidelines from NEI 95-10 to prepare this portion of our application.

There are three major categories of scoping. The first category is safety-related equipment, which is in Part 54.4(a)(1). There's a definition there of what is safety related. For ANO 1, we had a site-specific component level Q-list. And this Q-list uses a definition for safety related that matches the definition in the 54.4(a)(1). So we were able to go right to our component level Q-list at the site and basically print out a list of the equipment

that was in scope that met the (a)(1) requirement.

DR. BONACA: I have a question. I would like a clarification. During the Subcommittee meeting, you indicated that the scoping and screening for mechanical class 1 components was done using the B&W --

MR. YOUNG: Yes.

DR. BONACA: -- Owners Group topical reports. Could you expand on that? Is it the whole class 1 components, the mechanical ones were done from those topical reports? Or did you have to use the Q-list really to include also the Bechtel components?

MR. YOUNG: We did use the topical report as the core of our review, and then we did a site-specific comparison against the topical to ensure that we were enveloped. We did have some areas where we were different, and so we documented that in our site-specific documentation.

DR. BONACA: Because you had a number of Bechtel components.

MR. YOUNG: Yes.

DR. BONACA: I believe that they would not be identified by the -- or would they be identified in the topicals?

MR. YOUNG: No. The B&W components --

now, Mark Rinckel is here from Framatome, and he helped us with that. Go ahead, Mark.

MR. RINCKEL: Yes. This is Mark Rinckel of Framatome. We did include in the RCS piping report Bechtel-supplied or AE-supplied piping. And so what we had to do for Arkansas was to show how we're bounded, and so we had to reference site-specific information. It was included in the topical.

DR. BONACA: So also the Bechtel component.

MR. RINCKEL: That's correct.

DR. BONACA: Thank you.

MR. YOUNG: Okay. The second category is the non-safety-related structure systems and components that are part of the 54.4(a)(2). These are non-safety-related components that could prevent the accomplishment of a safety function. For ANO 1, we had very few components that fall in this category, because of our definition of Q or safety related would include most of these support type systems that are sometimes classified as non-safety related.

We did have a few, though, that did fall in this category. For example, our category two over one seismic supports were in this category and a few others. So we identify some additional equipment that

fell into this (a)(2) category.

And then (a)(3) was the final category for scoping, which included what we sometimes refer to as the regulated events -- fire protection, EQ, pressurized thermal shock, ATWS, and station blackout. And here we used our site-specific documentation for each one of these reviews and identified the structures and components that were relied upon to accommodate these regulated events.

DR. BONACA: Just a question: On the seismic two over one, you included not only the supports but also the piping segments.

MR. YOUNG: Yes. Yes. When we did our aging management review for the structural, we included -- the way we did the program for evaluating the aging effects on the supports and the piping is the Maintenance Rule Walkdown Program. So when they do that walkdown, they include both the hangers and the piping that the hangers support.

DR. BONACA: Yes. Because I know it's an issue that is being disputed on a different application, and I just wonder -- in fact, I don't know where the industry is on this. I mean is it -- you didn't have any objection to -- just your program actually included the segments.

MR. YOUNG: Right.

DR. BONACA: So you didn't have to --

MR. YOUNG: The existing program.

DR. BONACA: -- make an exception.

MR. YOUNG: Yes, right.

DR. BONACA: Okay. Thank you.

MR. YOUNG: Okay. And that's the summary of the scoping section of the application.

On the next slide, on page 6, is the screening activities. Once we had completed the scoping, we went through the screening process to determine which components in those systems and structures that were in scope required an aging management review. Again, we used the material in the rule itself and the guidance document that was provided by NEI in 95-10.

The first effort was to identify the passive structures and components that had an intended function that required an aging management reviews. And the definitions for passive and the intended functions are covered in the rule. We applied those definitions. We also then identified those passive structures and components that were not subject to periodic replacement. In other words, they were long-lived and passive.

The screening for the mechanical components was, again, done for -- the class 1 was done using the B&W topical reports, the same reports that Oconee used. And then for the non-class 1 mechanical, we did a site-specific review using the guidance in NEI 95-10. For the electrical and the structural components, these were also performed on a site-specific basis using the guidance of NEI 95-10. Okay. And that's a summary of the screening process.

Then on the next slide, on page 7, we go into the actual aging effects identification. At this point, again, it's all split up by discipline. We use the guidance of NEI 95-10. The aging effects were identified for the class 1 components using the B&W topical reports. The non-class 1 was done on a site-specific basis. At this point, we did rely on another B&W guidance document, which is sometimes referred to as the mechanical tools. This is the information that we summarized in Appendix C of our application.

The mechanical tools was a document that was created to help ensure consistency when we did our aging effects review. And this document was used for -- we had about 25 non-class 1 mechanical systems that we had to perform an aging management review on. So we relied upon this B&W guidance document to help us

go through that process and make sure that we consistently identified the same aging effects for each system. That document --

DR. BONACA: I'd like to ask a question. This must have been a pretty time-consuming portion of the effort.

MR. YOUNG: Yes.

DR. BONACA: If the GALL report had been finalized by the time you were preparing the application, would it have been much more efficient to use that or would you have used that?

MR. YOUNG: Yes.

DR. BONACA: I'm trying to understand how much the process would have been helped by the existence of a generic document like the GALL report.

MR. YOUNG: This portion of the process I don't think would be any shorter with the GALL report, but we would definitely have used it. It would have helped validate the conclusions that we came to. I think the overall intent of the GALL report is for the utilities to use to validate the work that is done, and then be able to then, with some confidence, go forward and say, "Well, this already has been reviewed by NRC, so we don't have to worry about new issues coming up."

DR. BONACA: It would certainly minimize a number of questions.

MR. YOUNG: Yes. That's the area where I think the benefit is, is that once you go through the process and use the GALL to validate what you've done, then you have some confidence going in with your application that that's essentially been pre-reviewed, and you know what the questions might be for that.

DR. BONACA: Thank you.

MR. YOUNG: Okay. The next area was the electrical review. Here we used the Sandia aging management guidelines and what's the spaces approach. This was, again, to help ensure consistency. The Sandia guideline was a basis for that. This is the same type of review that Oconee did and Calvert Cliffs, so we were following the examples that had already been set for the electrical.

And then for the structural and structural components, there was another B&W guidance document that's sometimes referred to as the structural tools. And that document was used, again, to help us ensure consistency as we went through all the various reviews of the buildings that were in the scope of license renewal.

There were several -- at this portion of

the review, and in our application, there were several lessons learned from both Calvert Cliffs and Oconee that we applied in our application, and we feel like that was a big part of the reason for the reduction in the number of requests for additional information was our efforts in this particular area to deal with issues that had come up previously on the first two applications in our application.

And in addition to that, we got some guidance from the NRC in the form of a standard format. And in that standard format for the application, we also got some guidance on how to present the material based on the review results that came out Calvert Cliffs and Oconee. And we tried to apply that lessons learned from the NRC staff, and we think that, too, was a big benefit in reducing the number of RAIs.

Okay. Then on page 8 of the slides is the aging management programs. Once we had identified the aging effects, we looked at the aging management programs that were needed to manage those effects. We identified a total of 29 aging management programs, or actually major groupings of programs. Some of these program titles you see here are actually a collection of programs. Out of that, only seven of the 29 are

new programs. There were 22 that were existing programs that were already in place at A&O.

The new programs included such programs as buried piping inspection, electrical component inspection, some pressurizer examinations, the vessel internals program, spent fuel pool monitoring and some others. And they're listed in a later slide.

For the existing programs, there were 22 of those, and those included such things as our ASME Section 11 In-Service Inspection Program, our Borax Acid Corrosion Prevention Program, chemistry control, which included primary and secondary chemistry, our Preventive Maintenance Program, and this is one that included a large number of preventive maintenance activities. So even though it's only listed as one program, it includes a large number of individual preventive maintenance activities. And, again, there were a total of 22 of those.

These 22 programs probably represent aging management programs for 95 to 99 percent of the components that were in scope. The seven new programs are actually very limited in scope as far as the number of components that they cover. So the existing programs cover the majority of the equipment.

DR. BONACA: Mr. Young, one of those

existing programs is this CRDM Nozzle and Other Vessel Closure Penetration Inspection Program.

MR. YOUNG: Yes.

DR. BONACA: I'm sure this is a question you were expecting to come today. And it clearly gives you an opportunity to see how effective the problem that you reference in the application would be in light of the recent findings of the colony and those at Arkansas, I believe. And I have a question that you would comment on that. And also that comment on possible changes you may have to make to the program --

MR. YOUNG: Okay.

DR. BONACA: -- to deal with the findings.

MR. YOUNG: Okay. Yes, the cracking that's been identified at Oconee and at Arkansas in the CRDM nozzles was found using our existing aging management programs. The Boric Acid Corrosion Prevention Program was probably the lead indicator, at least at Arkansas, when we went into the inspection -- the beginning of the refueling outage, we found the boric acid crystals on the head of the vessel, and that led to subsequent investigations that identified the cracking that had occurred in the CRDM nozzles or in the weld.

From that, we initiated our corrective action program, which is also part of our aging management programs to do a root cause evaluation and to look at the extent of condition, and to look at any needs to modifications to existing programs. And the two programs that may be affected -- or actually will be affected by those findings are the Alloy 600 Program and the CRDM Nozzle Inspection Program.

So those activities are currently ongoing. They're part of our existing aging management programs, and we expect some modifications to those existing programs based on the operating experience that we've gained recently.

DR. BONACA: Is this the first indication of cracking that you have seen at Arkansas One?

MR. YOUNG: Now, Mark Rinckel is here from Framatome. He's our expert. I'll let him answer that question.

MR. RINCKEL: Yes. Mark Rinckel, from Framatome. Actually, it's the second; the first CRDM, but the first Alloy 600 issue was in the pressurizer nozzle. It's a partial penetration nozzle that I think failed back in 1991. So it's actually the second occurrence at Arkansas.

DR. BONACA: Now, your program, if I

remember, was referencing inspections of Oconee, and then you would perform the inspection based on the findings from the Oconee inspection, correct?

MR. YOUNG: Well, I think on the CRDM nozzle, we are doing inspections in addition to the inspections at Oconee. We're sharing information --

DR. BONACA: Okay.

MR. YOUNG: -- but we're not dependent on Oconee in this particular case. There are some other programs where we are dependent, but in this case we are doing our own inspections and then comparing those results with Oconee to see if either one of us need to change our programs.

DR. BONACA: So you have a commitment to inspection at every shutdown for refueling?

MR. YOUNG: Mark, do you know the frequency on the inspections for the CRDM nozzle?

MR. RINCKEL: I think that's still being determined, but initially, and what's stated in the application was that ANO was amongst the least susceptible and was not predicted to see any cracking until after 48 fpy. Once the incident at Oconee Unit 1 happened, that changed everything, and, as Garry said, the program has now changed. But I think that's still being determined what the inspection frequency

will be. That hasn't been determined.

DR. BONACA: Because I have an exhibit from some presentation from Framatome that shows Arkansas to be the one with an inspection at every cycle. That's what I thought. That's why I asked the question.

MR. YOUNG: Yes. There have been some very recent changes, and all of this is being coordinated through B&W Owners Group. So the ultimate solution for the inspection frequency, both at Arkansas and at the other B&W plants is coordinated. There have been meetings with the staff on that specific issue. The long-term resolution will be the findings from the B&W Owners Group effort, and we'll incorporate those into our aging management programs.

DR. BONACA: How difficult are these nozzles to access for inspections at Arkansas?

MR. YOUNG: They're fairly difficult, yes. You have to get --

DR. BONACA: You do not -- I mean so many of the other PRWs have difficulty because they have insulation, and it makes it very impossible to see from outside unless the full installation is removed.

MR. YOUNG: Well, I believe these inspections are on the inside -- the welds themselves

are on the inside of the head, so I know the inspections that we did and the weld repair were done, obviously, with the head off the vessel on the headstand, and they had to work on the inside of the head. Mark?

MR. RINCKEL: Again, Mark Rinckel from Framatome. The control drive service structure that we have at the insulation is not an issue. We're able to see really all the CRDM penetrations with a visual inspection. And I think we differ from Westinghouse and CE in that regard. So being able to see the boric acid from the outside is not an issue for us. And we've done safety assessments to show that the cracks are predominantly axially-oriented; this is not a safety concern for the B&W design plants. So we should be able to see these.

DR. BONACA: Now, just a question I have is regarding Oconee 3 since --

MR. RINCKEL: Yes.

DR. BONACA: Oconee 3, when was the last inspection they had prior to the February 2001 inspection?

MR. RINCKEL: As far as visual from the outside, I can't answer that. The initial integrated program had Oconee Unit 2 as the lead indicator or

would be the lead plant, and that inspection included a volumetric from the underside of the vessel. And I believe that was somewhere around 1996.

DR. BONACA: I'm trying to understand. This inspection comes and there are up to nine nozzles --

MR. RINCKEL: That's correct, yes. At Oconee Unit 3 there are nine.

DR. BONACA: What is the rate of development of these cracks? That's what I'm trying to understand. And to understand that rate of development I have to understand the period that went between the two inspections.

MR. RINCKEL: Yes. I think the EPRI model that was used to rank the CRDM penetration is being re-looked at and has been completely revised. And they're really looking at Oconee Unit 3. Everything is being normalized now to ONS 3, and I think all of the NW plants will be inspected -- TMI and Crystal River 3 as well.

MR. ELLIOT: This is Barry Elliot, NRC. There are two issues here: CRDM nozzle cracking, and there's a susceptibility model which was used to pick the worst plants. There's a new issue that has just occurred, which is Alloy 600 weld cracking. That is

a problem we're having now. And that's a separate issue. It is being addressed by the staff currently.

As far as the susceptibility model that inspects the 600 nozzles, that was used -- that model was used by this plant in an expanded scope beyond the CRDMs, used for other components. And they have identified other components that need inspection. The susceptibility is in question because, as Mark said, ANO 1 was not one of the limiting plants, and yet it had the cracking.

The cracking is probably also related to the weld problem, and that weld problem -- the problem is that once the crack goes through the weld, the reactor coolant now is not -- it is no longer under priority chemistry control. It is now outside the confines of the reactor coolant pressure boundary, and it doesn't have the same chemistry anymore. So the rate of crack growth is going to change from what we -- which all the models predict. This is today issue. It is being evaluated today, and we recently put out an information notice on this.

DR. SHACK: But I think Mario's question was in the context of the license renewal application. When you have a new phenomena here where you do have the weld cracking, you now have the potential for

cracking from the OD of the nozzle, the circumferential cracking, which is really different than what people -- the safety evaluation was looking at axial cracking and the conclusions. But that's incorporated into the license renewal process in the sense that you're doing this experience update, and that's why the staff feels that it can go ahead with the approval, even though you really don't know what the answer really is going to be at this point.

MR. ELLIOT: Yes. Our work is through the current license and whatever occurs during the current license, whatever inspections are going to be required, will be carried forward into the license renewal period.

MR. PRATO: Part 54 requires that.

DR. BONACA: Although if an issue of this nature would come during the extended license period, you would have the same ability of working with the licensee to develop changes to the program. So I mean this is a -- okay.

MR. KUO: Yes. That is exactly right, Dr. Bonaca. The regulatory process carries forward into the license renewal period. Whatever the resolution here in today's space will be carried into the license renewal space.

DR. SHACK: It just seems a little strange at the moment that you're approving an aging management program for the drive nozzles when at the moment you don't have an acceptable, or you don't know whether you have an acceptable aging management program.

MR. ELLIOT: Well, I don't think we do have an acceptable aging management program simply because the cracks went right through. But we will, and that's -- you know, over the long-term that's what the goal is, and that's where we're headed.

DR. SHACK: Okay. But that's a today issue, and it will be addressed and will just carry over.

MR. ELLIOT: Yes.

DR. BONACA: I'm not sure whether I would characterize it as not an acceptable aging management program for license renewal, I mean. Today it is.

MR. ELLIOT: Yes.

DR. BONACA: For license renewal, all I need to see is you're flexible enough to incorporate promptly changes that result from the findings that you have. I mean we cannot expect that there will be no issues arising over the next 40 years of operation or whatever. The important thing is that there is a

program in place, and it is flexible enough to accommodate and to incorporate changes.

MR. ELLIOT: Yes.

DR. BONACA: So you would conclude, too, that --

DR. SHACK: I conclude that you're right.

(Laughter.)

DR. BONACA: -- for license renewal that's an important issue.

MR. KUO: I might also use this opportunity to mention that there are other technical reviewers here sitting in the audience that they are ready to answer any questions you might have later on.

DR. BONACA: Yes. No, I think it would inappropriate for us to expect a solution to this issue right this minute. We are not expecting that. But, certainly, an understanding of how, from a perspective of license renewal, the extent to which the programs which are committed to in the LRA are able to accommodate the findings. And that's really proof to us that the programs are effective.

MR. YOUNG: You know, we have the enveloping aging management program of our corrective action process, our Non-Conformance Program, and that applies to all of our individual aging management

programs, including the CRDM Nozzle Program and the Alloy 600 Program. But if we were to have some problem with one of our other programs in the future, they too would be subject to that Non-Conformance Program, which would include an evaluation of the root cause of the problem and corrective action, which would possibly include changes to those programs, either in frequency or inspection methods or scope. So all of our aging management programs are subject to that adjustment as we get additional operating experience.

DR. BONACA: Any other questions on this issue? Thank you.

MR. YOUNG: The next slide, on page 9, is the time-limited aging analysis. And, again, this was done as somewhat of a separate activity from the aging management reviews, but it was also done in conjunction with those reviews. We had a list of the TLAAs, which were evaluated. This list is very similar to Oconee. It included such things as the reactor vessel neutron embrittlement, metal fatigue, EQ, reactor building tendon pre-stress, and boraflex in the spent fuel racks, in addition to some others. So, again, this list was consistent with the previous applicants, and we performed our evaluation and

documented the results in the application.

Okay, the next slide, I would just like to conclude on the application itself. We, again, utilized a number of the lessons learned from Oconee, from Calvert Cliffs, and from the rest of the industry. The number of NRC requests for additional information was reduced relative to the Oconee application. We had approximately 265 RAIs for Arkansas versus about 350 or so for Oconee. Again, I think this, at least in some sense, reflects the application of lessons learned. We took the RAIs from Oconee and tried to address as many as we could in our application. Obviously here there's still room for improvement. We'd like to get that number even lower than 265, and I think subsequent applicants will be able to do that.

On the number of SER open items, we had six and Oconee has approximately 49. Again, we applied lessons learned from Oconee to assist us in reducing this number and the lessons learned from the NRC review of the Oconee application.

In summary, the license renewal application is stable and predictable, and we appreciate the efforts of the NRC staff to help us reduce the schedule for the review of this application

from the original 30-month schedule, which we started out with in February of 2000, and we're now down to a 17-month schedule. So we really appreciate the efforts that went into accomplishing that.

And in particular, we'd like to acknowledge the effective management of this review by Mr. Bob Prato on the safety reviews and Mr. Tom Kenyon on the environmental reviews. Both of these individuals were a great contribution to this process, and we appreciate their efforts. And that's all I had on the application. Thank you.

DR. BONACA: Thank you. Mr. Prato?

MR. PRATO: Okay. On the safety evaluation, again, I'm Bob Prato. At the end of each of the major topics -- scoping, aging management review, and time-limited aging analysis -- there is a slide on the open items that were identified at the end of the first safety evaluation. The last four pages of this handout has the summary of the open items and a summary of the resolution of each of those open items. So as I go through this, we'll stop and we'll talk about the open items that we found in each of these sections. And both myself and Mr. Young will try and answer any questions you might have as to the resolution.

I'll begin with scoping. If you remember, the Oconee application had a number of questions on the scoping. Both plants, Arkansas Nuclear 1 and Oconee Nuclear Station were originally designed to barriers to release of fission products. However, in 1987, about that time frame, ANO 1 performed a design basis reconstitution. As part of this design basis reconstitution, they revised a Q-list to criteria that is consistent with 54.4(a)(1) for safety-related components and 54.4(a)(2) for non-safety-related components, which can effect safety-related functions.

They used the accident analysis in the US FSAR. They used the environmental and exterior vents in their design basis reconstitution. They used site-specific and applicable industry operating experience, and they also used generic communications. The applicant also incorporated lessons learned from the Oconee scoping review. The chilled water system, skid-mounted equipment, structural sealants, ANO 1 ventilation sealants, water stops, expansion joints, electrical cables, fire-detected cables, and buried pipe were all not excluded from the aging management review in the original ANO 1 license renewal application.

ANO 1 aging effects discussed and accepted

by the staff were consistently applied by the applicant based on Appendix C of the license renewal application, as discussed previously. And corrective actions, ANO 1 committed to 10 CFR Part 50, Appendix B for all license renewal corrective actions, safety-related and non-safety-related both. That includes corrective actions, the confirmatory process, and document control activities.

As far as the open items for scoping, initially the applicant did not identify a flow control orifice -- I'm sorry, the applicant did not identify flow control as an intended function of an in-line orifice that controlled the injection of sodium hydroxide for pH control. In resolution to this item, the applicant did include the flow control function. And because the orifice is made of stainless steel and is subject to cracking, the applicant added the orifice to the inspection program used to manage other stainless steel components within the sodium hydroxide system as their resolution.

The second item was fire protection. There were five sets of components that the staff was concerned about. They were the fire protection jockey pumps, the carbon dioxide system, fire hydrants, the water supply to the low level radwaste building fire

protection system, and the piping to the manual hose station as being within the scope of license renewal and subject to an aging management review. The applicant took the position that it was never part of the current licensing basis, these components. And the staff felt that it was necessary to include them based on the rules under Part 50.

We had a number of meetings on these items. What the final resolution was was that the applicant realized that even though it wasn't part of their initial current licensing basis, that the fire protection jockey pump and the fire hydrant should be included within the scope of license renewal. And they did include it, performed an aging management review, and identified aging management programs for those components.

MR. LEITCH: When you refer to the fire protection jockey pump, are you speaking specifically of the casing?

MR. PRATO: Just the casing; yes, sir.

MR. LEITCH: Just the casing. Okay, I understand. Thank you.

MR. PRATO: As for the other three items, based on the applicant's presentation to the staff, the staff found that these components were not

required to be included within the scope of license renewal, and therefore this item was close. Initially, when we started this review and we identified these differences, we thought we had potentially a Part 50 item, because it wasn't part of the licensing basis. But based on the resolution, because both the staff and the applicant agreed what should have been included and what shouldn't have been, it did not even end up as a Part 50 item.

As for the aging management review, aging effects, the applicant addressed void swelling in the reactor vessel, reduction in fracture toughness of the reactor vessel internal task components by thermal embrittlement and irradiation embrittlement, cracking and loss of material of letdown cooler tubings, loss of material for external Ferritic surfaces due to boric acid wastage, irradiated-assisted stress growths and cracking for baffle bolts, and cracking of reactor vessel internal non-bolted items as applicable aging effects.

As for intended functions, the applicant did include heat transfer as an applicable intended functions for heat exchanges. These things were already included in the aging management program in the initial license renewal application as lessons

learned from Oconee.

As for the aging management review, they performed an aging management review on all the service water piping, including the copper, brass, and ductile iron, et cetera, all the materials that are within the scope of the license renewal. But they did not perform an aging management review of the tendon gallery in the license renewal application, consistent with the staff's conclusion on the Oconee application review. They did not perform an aging management review of the pressurized spray head, contrary to Oconee, which did end up performing an aging management review of the spray head. ANO 1 does not use it for their accident analysis at all, and therefore it was not within the scope.

As for aging management, the applicant used performance monitoring consistent with Generic Letter 8913 for managing filing in the service water system. Cracking of Alloy 600 and Alloy 82/182 will be monitored during the period of extended operation. And aging of small-bore piping will be managed by risk-informed methods used to select reactor coolant system piping welds for inspections. These are all differences between ANO 1 and Oconee.

DR. BONACA: This is an existing program?

MR. PRATO: Excuse me, sir?

DR. BONACA: Is this small-bore piping management risk-informed --

MR. YOUNG: Yes. It's a fairly recent -- it was a change. We just, in the last couple years, switched to the Risk-Informed In-Service Inspection Program, and that was when we included the small-bore piping at that point.

MR. PRATO: That's been reviewed and approved by the staff as well --

MR. YOUNG: Right.

MR. PRATO: -- independently of this effort.

DR. SHACK: Okay. So you had the small-bore piping when you did go to the risk-informed inspection. You included it rather than as part of the license renewal, it was actually --

MR. YOUNG: Right. Right. Right. We had already gone to the small-bore piping inspection as a result of the risk-informed ISI, which was prior to doing our license renewal review. So we're able to take credit for that.

DR. BONACA: Why would you do that, I mean, technically? Some other applicants claim that they don't need to inspect small-bore piping.

MR. YOUNG: Well, if you haven't gone to the risk-informed ISI, then you would not include the small-bore piping under Section 11 requirements. They currently do not require you to do a volumetric-type inspection, just a visual inspection. But during the risk-informed review, and that's very plant-specific, we did identify some locations of piping welds that met the criteria for both risk and susceptibility that we did include them for doing volumetric inspections. So I don't think very many plants have gone to risk-informed ISI yet is part of the reason for the issue.

DR. BONACA: But given your findings, wouldn't that suggest that maybe one-time inspection for other applicants is not sufficient?

MR. KUO: Well, there's -- as you know, in the GALL report right now, that we do require one-time inspection for the small-bore piping, but this issue is continually under review. And I believe that in the industry they have also MRP Program that also uses the risk and they have concluded that something should be done. And they are about to make recommendations to code body. So if this materializes later on, the staff will certainly incorporate lessons learned from these activities.

DR. BONACA: Thank you.

MR. PRATO: Okay. As for the open items identified during the first safety evaluation, there were two for the aging management review. The first one was a summary of 11 different aging management programs that needed additional information to be included in the FSAR supplement. Each one of those 11 items are identified in the attachment on the back and the additional information that they agreed to put into the FSAR supplement.

If you get an opportunity to look at the operating license, we do not have a license condition for the FSAR supplement. The reason is, is based on the findings of this Committee, at that point, the applicant has agreed to incorporate the supplement into the FSAR prior to the Commission decision. So an open item license condition wasn't needed at that point. So that supplement will be part of their FSAR prior to the Commission making their decision and issuing the new license.

The other open item, the applicant did not identify an aging management program for buried, inaccessible medium-voltage cables exposed to groundwater that are within the scope of license renewal and subject to an aging management review. When we identified this, the applicant looked at their

aging management review and incorporated it. As a resolution, they offered something a little bit more unique than Oconee. They offered to do either what Oconee did, which is to do some sort of a measurement on the cabling to try and identify if the installation is breaking down and to monitor the water that these cables are exposed to. Or they will do a periodic replacement of those cables.

The reason they chose to take that second option is because they've had three failures on-site, and each time they did do Megger testing not too long before the failure had occurred. And if something is not developed that would accurately identify degradation of the installation far enough in advance so that they could prevent the failure from happening, they agreed to just go through a periodic replacement based on plant-specific and industry experience.

Did I explain that accurately, Garry?

MR. YOUNG: Yes. Right now we're evaluating basically the qualified life of this buried cable. It's non-EQ, obviously. It's outside of the EQ Program because it's not in a harsh environment relative to EQ. And we have had some failures. So we're looking at now determining whether or not we can come up with a qualified life based on operating

experience that would warrant just doing a periodic replacement or do the inspection. As the inspection results get better, we may choose to use inspections. Or if they don't get better, we may choose to do periodic replacement.

DR. BONACA: This issue, too, will have some generic implications?

MR. KUO: Yes, sir.

DR. BONACA: As to the adequacy of just simply doing a measurement?

MR. KUO: Yes. We certainly would take note of that, and we will incorporate any lessons learned from this later on.

DR. BONACA: The reason why I'm raising this issue is that we see a number of applications coming through with different Project Managers. It's not clear how these lessons learned are shared among the different project reviews.

MR. KUO: Well, in fact, there is -- we have an office letter 805 that describes or detailed all the procedures that we have followed. So we hope that these kind of lessons learned will be incorporated into the official reviews rather quickly.

DR. BONACA: Clearly, for us, it would be more difficult in the next application to accept just

the measurement of the buried cable as a means of identifying --

MR. KUO: Well, these issues, like a one-time inspection for small-bore piping and the buried cables, are all really issues of contention. It's constantly under review, and we certainly will take a continuous look at it.

DR. BONACA: And GALL certainly applies for this will be documented.

MR. KUO: Yes, sir.

DR. BONACA: And that's why we've asked for frequent updates.

MR. KUO: Yes, sir; we agreed to that.

DR. UHRIG: Would these cables be actually replaced or would there just be a new cable put in parallel and the old one left in place?

MR. YOUNG: They'll probably be replaced. They're in conduit underground, so they would just be pulled out.

DR. UHRIG: They can be pulled?

MR. YOUNG: Yes.

DR. UHRIG: Okay.

MR. PRATO: During the inspection process, shortly before we did the aging management review inspection, they had their third failure. And they

had the cables out on the grounds, and we took a look at it. We also found out at that time that they tried to do analysis to find the root cause of the previous two failures without any success. The root cause analysis, the laboratory analysis, was unable to identify the specific mechanism that failed.

DR. UHRIG: Was there moisture in the pipes when you pulled the cable out? Was there evidence that there was moisture in there?

MR. YOUNG: There was evidence of moisture, yes. Yes. Part of the problem we're having is that the inspection of the cables is not conclusive as to the reason for the failure. It could have been a manufacturing defect that was originally in the jacket or it could have been some sort of aging mechanism. But by the time they get them to the laboratory for inspection, they haven't been able to conclusively identify the root cause.

MR. LEITCH: The testing program you're referring to is the Megger Program; is that right?

MR. YOUNG: Yes. The industry currently is evaluating options for testing, but right -- what we used was a Megger test. But through EPRI and through some industry efforts, they're looking at some other options for maybe other ways to test.

MR. LEITCH: Right. And it was shortly after the Megger, if I understood you correctly, that these failures occurred?

MR. YOUNG: Yes. Probably within 12 months or so of the previous inspection we had the failure, the most recent failure.

MR. LEITCH: Thanks.

MR. KUO: Dr. Bonaca, for the record, I just want to correct what I said earlier. I was informed by Mr. Paul Shemanski that the issue actually has been copied in the final version of the GALL. I'll let him explain it to you.

DR. BONACA: Okay.

MR. SHEMANSKI: Well, basically, we took the information -- actually, this issue started back in October of '99, I believe, with the Davis-Besse event where medium-voltage cables on the service water systems catastrophically failed due to moisture intrusion. These were cables that were in four-inch PVC pipes underneath the turbine building floor and somehow -- we believe it to be groundwater -- got in. And over time, that water actually migrated through these 4160 volt cables into the insulation, resulting in ultimate dielectric breakdown.

And as such, we took that information and

the information from Arkansas. We have incorporated that into GALL. It's in there under aging management program for medium-voltage cables, subject to significant moisture and voltage. And we do even recommend several tests that might be considered. These are actually used by Davis-Besse -- the partial discharge test and power factor test. We found those are more sensitive. Megger is too gross a test to detect insulation degradation. So I think we've captured the operating experience in GALL -- well, I don't think we have, so we're comfortable licensees, future applicants, will be aware of this issue.

DR. BONACA: Thank you.

MR. KUO: And I also would like to mention that the April 2001 version of the GALL has been released to the public.

MR. PRATO: Okay. Time-limited aging analyses fatigue. The applicant considered cumulative effects of fatigue for the containment liner plate in penetrations, and the reactor coolant system environmental assisted-fatigue, consistent with GSI-190 in the license renewal application initially.

As for fractured toughness, the applicant considered fractured toughness related to the acceptability of reactor vessel internals under loss

of coolant and seismic loads in its reactor vessels internal aging management program, consistent with the topical report, BAW 2248.

For flaw growth, the applicant considered flaw growth in accordance with the ASME boiler and pressure codes, Section 11 of ISI requirements in the license renewal application, consistent with the topical report, BAW 2248.

For neutron embrittlement of the reactor vessel, the applicant performed analysis to evaluate the impact of neutron embrittlement on reactor vessel integrity.

DR. BONACA: I have a question regarding the specimen for the vessel. It wasn't clear to me reading the application, you have specific specimens for your vessel, Arkansas One.

MR. YOUNG: Yes. I may need to get with Mark here. I think the specimens for the Arkansas vessel I don't believe are in the Arkansas vessel anymore. I think they're in another --

MR. RINCKEL: That's right. Mark Rinckel, Framatome. Yes, they are being irradiated in Crystal River 3 and Davis-Besse Unit 1. And they're part of the integrated program, which is a MIRVP.

DR. BONACA: Thank you.

MR. PRATO: Pressurized thermal shock. The applicant performed an analysis to the criteria in 10 CFR 50.64 and Sharpy upper shelf energy analysis to Appendix K of the ASME code for the end of the period of extended operation.

Containment pre-stress tendons. Concrete reactor building tendons pre-stress will be managed during a period of extended operation using ASME Section 11, IWL In-Service Inspection Program.

DR. BONACA: Was this an open item?

MR. PRATO: Yes, sir.

DR. BONACA: Yes, it was.

MR. PRATO: Yes.

MR. YOUNG: Yes. The issue here was in the original application we provided just the description of the ASME Program, but there was some additional monitoring that the staff wanted to see the results or the information regarding. And it was really, I think, more of a miscommunication. We were misunderstanding what the question was, and the by the time we got to the open item, we finally got down to the details and were able to provide the needed information.

DR. BONACA: Yes. You needed to develop curves, if I remember.

MR. YOUNG: Yes. Right.

DR. BONACA: Okay.

MR. PRATO: For reactor building liner plate fatigue analysis, the applicant demonstrated that the original fatigue analysis is valid for the extended period of operation. For the reactor vessel underclad cracking, fracture mechanic analysis indicated that the reactor vessel will have adequate fracture resistance through the period of extended operation. And for the reactor vessel in-core instrumentation nozzles, flow-induced vibration on reactor vessel in-core instrumentation nozzles have been projected to the end of the period of extended operation.

DR. UHRIG: Is that a movable system or is that a fixed system?

MR. YOUNG: Mark?

MR. RINCKEL: Mark Rinckel of Framatome again. The nozzles that they're referring to are fixed and attached to the bottom of the head. We don't have a system like Westinghouse does with the thimble tube. Our in-cores are actually exposed to the reactor coolant, and they move within the guide tube and through the nozzles and up into the fuel assembly.

DR. UHRIG: It's not like the Crystal System.

MR. RINCKEL: Crystal River is a B&W plant. It is, yes, yes.

DR. UHRIG: Is the in-core instrumentation essentially the same?

MR. RINCKEL: Yes. The in-core instrumentation is, but there's not a separate thimble tube or pressure boundary. I mean the in-core itself is exposed to the reactor coolant, and it's made of different material. The stainless steel guide tube goes from the seal table to the bottom nozzle of the -- and the nozzle is attached to the vessel. And then it runs from there up through the internals and up into the fuel assembly.

DR. BONACA: Do you inspect these nozzles on a periodic basis?

MR. RINCKEL: The nozzles will be inspected from the outside in accordance with Section 11. It would be a VT-3 -- I believe VT-3 or VT-2 inspection. And then from the internal, it would be during when they pull the reactor vessel internals out. So you would look at both from the outside and the inside.

DR. BONACA: That would be once every --

MR. RINCKEL: That is correct, yes.

DR. BONACA: And I guess they're less acceptable?

MR. RINCKEL: Yes, they are. In fact, those things, if you remember from your history, they were repaired. They initially broke off at Oconee Unit 1, and then they were beefed up and repaired at all of our plants.

DR. BONACA: Thank you.

DR. SHACK: The wall thing isn't explicitly included at a time-limited aging analysis here; is that correct? It's not treated as a time-limited aging analysis?

MR. YOUNG: Right. We went back and evaluated whether or not we had any corrosion allowances or wall thinning that was based on time-limited aging analysis, and we did not find any in our documentation that took credit for that. So those were not identified as TLAAs for Arkansas.

DR. SHACK: So in your Flow-Assisted Corrosion Program, you have no measurable thinning in your feedwater piping?

MR. YOUNG: No. No, no. Okay. That falls in the category of being an aging effect, so that is included -- that was identified as an aging

effect when we did the system reviews. And we did identify the FAC Program as being the program that manages that. The TLAAs were strictly the analytical evaluations that were done in the original safety analysis to determine the safety of the plant. So if we had had an analysis that showed that we had a corrosion or an erosion/corrosion allowance that was valid for 40 years, then we would have evaluated here to extend it to 60 years.

DR. SHACK: But doesn't the flaw growth TLAA include flaws that you would find after -- that weren't considered in your original design and then you project that life?

MR. YOUNG: Yes. You're right, yes. For flaws, any time we identify a flaw then we do an evaluation for the remaining life of the plant. And those, too, were identified as TLAA. So, you're right, those get identified after the original design.

DR. SHACK: Why wouldn't wall thinning be in the same category as the flaw that you find?

MR. YOUNG: We didn't do any analysis to project that the walls would remain in tact for the life of the plant. When we did the evaluation for the FAC Program, we determined that we in fact needed an aging management program, not an analytical analysis,

to show that it would go the life of the plant, because in fact it won't.

DR. SHACK: Okay. But you mean you do an analysis to show that it will go till the next inspection.

MR. YOUNG: Yes. Right. But those are not classified as TLAAs because -- right.

MR. PRATO: One of the criteria for TLAAs is that it's projected to the current operating term.

MR. YOUNG: Right.

MR. PRATO: And that brings us to our open items. We talked briefly about pre-stress tendons. There were a number of different graphs that needed to be developed, and the applicant provided that prior to the final SE. And the staff found that acceptable. And the second item was the Boraflex Monitoring Program. This is kind of interesting in that the applicant initially provided a program similar to Oconee.

From the time they submitted their application to the time that the staff developed a request for additional information, they took some additional data on that monitoring program. And they found that the -- when they plotted that data, they found that the boraflex would not last through the

current operating term. As a result, it ended up being a TLAA.

Under Part 50, they're required to maintain a sub-critical margin, and if they can't maintain that sub-critical margin, they have to submit a plan to the staff for their review and approval. So they felt that it did not belong under Part 50. And the staff reviewed the definition under Part 54 for TLAA and concurred, because it is supposed to be for analysis that are projected to year 40.

Design Engineering Management did not feel comfortable in that resolution, removing boraflex as a TLAA. As a result, we spent some time with OGC, and OGC concurred with DE Management and said it does not necessarily have to be eliminated just because recent analysis shows it's not going to make it to the 40 years. So what the staff requested is that the applicant keep the program in place, the monitoring program in place until the resolution has been identified and that the boraflex life and the ability to maintain sub-critical margin can be established out through the period of extended operation.

DR. BONACA: You do have boraflex only in one region of your pool.

MR. YOUNG: Yes, that's right.

DR. BONACA: And in the other regions, you have Boral or some other material?

MR. YOUNG: I'm not totally up to speed on the details of our spent fuel pool, but we --

DR. BONACA: But there's no boraflex.

MR. YOUNG: Right. We do have some regions that have the boraflex and some that do not.

DR. BONACA: Do you already have a plan on how you're going to get rid of the boraflex?

MR. YOUNG: We're developing that plan right now. As Bob mentioned, the finding was fairly recent, and there are several options to correct the situation, and those are being evaluated. And probably within the next two years, we're going to wind up with a recommendation to take some action with either a different material or --

DR. BONACA: So you still have flexibility in your pool to move those assemblies in some different location as you --

MR. YOUNG: Yes. We still have some room in the pool for moving the fuel around, yes.

DR. BONACA: Okay. All right.

MR. PRATO: The next slide, slide 20, is just a list of the aging management programs. If anybody has any particular question on any of the

aging management programs, I'll be glad to answer them at this point.

DR. BONACA: I would like to go back a moment to the CRDM casings. And the question I have is -- I know that Oconee has already committed to repairs. Essentially, the repairs include re-welding. The question I have is, is the material being used for welding over? And I'm sure that Arkansas has some plan of that nature too. Is it going to be less susceptible to the same kind of failures? I guess what I'm driving at is are these steps that are being taken now to repair those cracks going to be -- are they being viewed as a permanent repair that should not be affected anymore by this phenomenon or is it going to be simply another time-limited repair?

MR. YOUNG: Well, I think the answer to that is it's still being evaluated. And I know the repairs that were done at Arkansas were different than the repairs that were done at Oconee, but I think it's part of this evolving process and analysis of what is the correct solution, where do we need to go from here. I think in the case of Arkansas, the repairs were done with the information that was available at the time, which was just within the last couple of months. And they're continuing to do the analysis on

the findings to determine if -- well, first of all, it will change our inspection program.

DR. BONACA: Sure.

MR. YOUNG: So that's definitely a change. And then it may require some subsequent repair actions or preventive actions based on the results of those analysis. But that's still being evaluated.

DR. BONACA: I guess what I'm driving at is that ultimately the measure of success of the program is going to be the ability of preventing an occurrence to happen again. And so right now really we don't know if these kind of repairs are going to be effective to do that. I mean we don't, I guess.

MR. YOUNG: That's my understanding. Now, there may be some people here from the staff or from Framatome that know more about the details of the work that's been done so far. But I know at Arkansas we're fairly early into the analysis. And like I said, we just finished the outage in which we found the problem, so I know there's still a lot of work going on in that area.

DR. BONACA: I understand that some of the materials are being changed, so there is some expectation that those changes in materials should lead to a different kind of performance, although we

cannot right now estimate whether or not they will prevent these kind of failures from occurring again. And so you have to rely on future inspections.

MR. YOUNG: Right. And I think, as mentioned earlier, the Materials Reliability Program, the industry program, is looking at this as well to see what changes are needed throughout the industry relative to this type of problem.

MR. PRATO: Before I go into the conclusion, are there any other questions?

MR. LEITCH: Earlier there was an indication that there were 22 existing programs, and here there are 28 listed. Is that just a different bean count or is there some significance to the difference in those numbers?

MR. YOUNG: Again, the way we count the programs is somewhat difficult, because it's a bean count issue. We all have the same list of programs, but in the application itself we would have a section, and then it would have an A, B, C part. So it depends on whether you count the A, B, C part or just the headings.

MR. LEITCH: Okay.

MR. YOUNG: That's really where we're at on that.

MR. LEITCH: Thanks. Just one other minor, very minor, comment. In the SER Chapter 5, there's a section about presentation to the ACRS, and the number of the ACRS meeting at which those presentations occurred is incorrect.

MR. PRATO: I'll verify that.

MR. LEITCH: It's just a nit.

DR. BONACA: That's a good point. I mean this is the first application for which we have not had an interim full Committee meeting. And, of course, as I mentioned before, there are good reasons for that. One was the low number of open issues identified, and we agree with the staff that there were no additional ones.

Second, the fact that there was a lot of lessons learned, and we actually asked the staff to articulate the presentation on the basis of comparison to the previous ones so that we could understand whatever we accepted the program for Oconee, then the program should be acceptable for Arkansas, unless Arkansas presents a better program, which in some cases did.

And the reliance on the standard application format, actually striving for it. The work that Arkansas did with the NRC I think was very

helpful, and the reliance on the guidance of NEI 95-10 made the application, I think, much easier.

And I point it out because we have been trying to have some demonstrations from repeated applications that in fact ultimately the guidance documents and the endurance of the guidance documents and previous experience will facilitate the review and improve the applications. And we, I think, have proof here in front of us.

MR. PRATO: Any other questions?

Okay. In conclusion, on the basis of the staff's review of the license renewal application and the applicant's response to the request for additional information and resolution to the open items, as documented in the safety evaluation report, the staff found that, one, the applicant has appropriately identified the aging mechanisms associated with passive, long-lived structures and components, as required under 10 CFR 54 and 10 CFR 54.21(a).

Two, the applicant has instituted the programs needed to manage age-related degradation of these structures and components such that there is reasonable assurance that ANO 1 can be operated in accordance with its current licensing basis for the period of the extended license without undue risk to

the health and safety of the public.

And three, the applicant has analyzed the time-limited aging analysis associated with ANO 1, consistent with the requirements of 10 CFR 54.21(c).

On the basis of these findings, Region 4's verification of these activities, and the Regional Administrator's recommendation, the staff requests that the ACRS provide the Commission with a favorable recommendation on the renewing of the ANO 1 operating license for an additional 20 years of operation. And that concludes our presentation for today.

DR. BONACA: Okay. Any questions from the members? Any perspectives you want to share regarding the application and the SER? If none, I would like to thank the staff, Mr. Prato and Mr. Young, for well-informed presentations. And I would like to also, again, recognize Arkansas for an application that facilitated that review. And I think it's been quite effective. And with that, I thank you very much, and I --

MR. KUO: And this concludes the staff's conclusion. And what I would take back, I think, there are three points here that we're going to check SER Section 5 and correct, if possible, the discrepancy in the numbers of the ACRS meetings. And

the second one is we will monitor the progress of aging management for both the CRDM cracking issue and the small-bore piping issue.

DR. BONACA: Small-bore piping, yes.

MR. KUO: And with that, of course, we will recommend that ACRS write a letter to the Commission for approval of the --

DR. BONACA: We will write a letter.

MR. KUO: Thank you.

DR. BONACA: Okay. Thank you very much. And with that, Mr. Chairman --

CHAIRMAN APOSTOLAKIS: Thank you very much. We were told that the review of the application was completed eight months ahead of schedule?

MR. PRATO: Yes, sir.

CHAIRMAN APOSTOLAKIS: And Dr. Bonaca completed his presentation half an hour, actually -- half an hour before schedule. There must be something going on with license renewal issues.

(Laughter.)

We probably overestimated what it takes to review those. Thank you very much, gentlemen; appreciate it.

MR. YOUNG: Thank you.

CHAIRMAN APOSTOLAKIS: As the members

know, we will meet again at 10:30 in the Commissioners' Room to attend to the Commission's meeting on nuclear research with Dr. Powers and Dr. Wallis leading the charge on behalf of the Committee.

Thank you very much, and we'll see you back here at 1:30.

(Whereupon, the foregoing matter went off the record at 9:55 a.m. and went back on the record at 1:30 p.m.)

A-F-T-E-R-N-O-O-N S-E-S-S-I-O-N

(1:30 p.m.)

CHAIRMAN APOSTOLAKIS: We're back in session. The next item on the agenda is a presentation on risk-based performance indicators. Mr. Mays, the floor is yours.

MR. MAYS: Thank you, George. Good afternoon. It's a pleasure to be back here before the ACRS to discuss our work on risk-based performance indicators. This presentation will be an abbreviated version of what we presented to the Subcommittee last month. The Subcommittee asked us to concentrate the proposed shutdown, performance indicators, the validation and verification, including comparison with the current reactor oversight process PIs, and the new alternative approaches for risk-based performance indicators that we've developed in response to internal and external stakeholder comments.

So as we did at the last meeting, our counterparts from NRR are here to briefly explain the relationship between the RBPIs and the reactor oversight process. And the rest of the presentation will be our summary of the work that we did to establish the technical feasibility of risked-based performance indicators as a potential enhancement to

the ROP.

We're seeking a letter from the ACRS addressing whether you see this work as potential benefit to the reactor oversight process, whether you think our technical approach is feasible, and whether you think we should continue to expand and/or add the proposed alternative approaches to the Phase 1 report. We issued the Phase 1 report in January. You have had it for a few months now, and we're going to look forward to see what comments you have from that.

Now, Tom Boyce, from NRR, who works in the Inspection Program Branch, is here to go over the NRR view of the interrelationship between the RBPIs and the reactor oversight process.

MR. BOYCE: Thank you, Steve. As stated, I'm Tom Boyce. I'm the Inspection Program Branch of NRR. You heard about the Reactor Oversight Program yesterday. I'm a member of the Branch who is responsible for that oversight process, and we would be the people who would be the users of the risked-based PIs.

I wanted to start just by talking about some of the environment surrounding the risk-based PIs and the direction we're going. In the Commission PRA policy statement and in their strategic plan, the

Commission articulated its intent to move in a more risk-informed direction, and we think these risk-based PIs are clearly a step in that direction. We also wanted to point out that the current reactor oversight process is a significant step in that direction. We think it's much more risk-informed, objective, understandable, and predictable than the previous oversight process that was in place.

We also wanted to point out that industry and the NRC have been responsive to larger movements, advances in information technology, and the collection of data is improving, the transmission of data is improving through the use of the Internet and personal computers. And the PRA models, specifically the SPAR models under development by the NRC and the PRA models that licensees are using, have continued to improve. And so against that backdrop, it's more ripe for risk-based PIs than we've had at any time in the past. Next slide.

DR. POWERS: May I ask a question? The industry, when it does risk assessments, it gets a certification from an industry group for the PRA that it uses.

MR. BOYCE: The question is do they get a certification?

DR. POWERS: Well, I believe they do.

MR. BOYCE: Okay.

DR. POWERS: And what I'm asking is what is the equivalent for the SPAR models?

MR. MAYS: Let me answer that, Dana. The SPAR models, the Ref 3 models that we're using for this program, we have instituted a process by which they get reviewed by the contractor and by us as they're being done. They're reviewed internally by NRC personnel when we get them. And we also have a process for doing on-site reviews where we go to the plants and look at the as-built, as-designed plant and what they've done in their PRAs to identify if there are any shortcomings that we've had in that.

In addition, we've been using the SPAR models for several years now in the Accident Sequence Precursor Program. So whenever we evaluate the risk significance of an event or condition at a plant using those models, we would send those out formally to the licensees to review, and we were getting feedback and comment on those during that process as well.

DR. POWERS: So you really don't have what I would call an independent review. And I'd invite Dr. Wallis to comment on his experience with people saying, "Gee, we've used a code for several years, so

it must be right."

MR. MAYS: Well, that wasn't the statement I made, but I was saying we have had the opportunity to get feedback from licensees about the validity of models we've used through the ASP Program. That's not a complete review, but it is more than nothing. And we are going to every site for the models that we're developing to have those reviewed by the folks on-site. So I think we have a pretty substantial process for being able to do that.

CHAIRMAN APOSTOLAKIS: Wouldn't it be a good idea, after the Agency agrees to some form of an ASME standard, to apply the standard to SPAR?

MR. MAYS: If we were to come up with a standard, I think that would be appropriate.

DR. WALLIS: I hate to use the word "independent" that was used this morning, but wouldn't it useful to have also some independent check on these things from -- I don't know where it would come from, but just between you and the licensees, I'm suggesting someone else might who was not so tied up in the process be able to contribute to improving or detecting --

CHAIRMAN APOSTOLAKIS: At this point, having the licensees review them may be good enough.

DR. POWERS: How can you possibly say that? I don't think that would inspire public confidence if I were a member of the public.

CHAIRMAN APOSTOLAKIS: Still, the program is under development. The numbers are not being used in any real way by the Agency, right? And they have 30 SPAR models. They plan to have, what, 70 more or 40 more? I mean it's really important at this point to make sure that their SPAR model for a particular plant is not off the mark. So by having the licensee review it, you get that assurance. But they are not really taking any regulatory actions yet, because eventually when they have the totality of the 70 SPAR models, then they will have to think about how to have maybe an independent review panel or somebody.

DR. POWERS: Well, I can see this now. You're going to bring a review panel and say, "Here, review 70 models."

CHAIRMAN APOSTOLAKIS: So you plan to have established a review panel that will be reviewing them as they are produced?

DR. POWERS: I don't know. That sounds like a good idea to me.

CHAIRMAN APOSTOLAKIS: And the other point is that let's not overexaggerate the value of these

review panels. I mean I can't imagine that they will do a review like Sandia did for Indian Point and Zion PRAs. I mean these panels will probably look at the overall approach, how did you do common cause failures, how did you do data analysis. But otherwise it's a huge job. I mean it's huge now. It's huge in the future.

DR. POWERS: And it seems to me that the pattern for the review has been set by the Agency in the kind of reviews that is applied to the codes that's developed for severe accident analysis.

CHAIRMAN APOSTOLAKIS: Can you elaborate on that?

DR. POWERS: They do a fairly detailed review. The panel actually exercised the models. They have a process set out, begins with are the intentions of the model. They do a top-down, then a bottom-up examination. They publish a report that has their complaints about the -- their comments on the models and includes the response from the model developers.

CHAIRMAN APOSTOLAKIS: But here you're not talking about a model that will be used to produce results under different conditions. Here you are talking about PRA for a particular unit. So, you

know, that approach will have to adapted to this particular problem.

DR. POWERS: Well, I think it's adapted to every curve, but it seems like a pretty good approach to me.

DR. SHACK: And it will be independently checked by the PRA that the licensee has. I mean, obviously, I think if the licensee is getting different results, then you're certainly going to hear about it.

DR. POWERS: What I would worry about is if you've overlooked some vulnerability in the SPAR model that the licensee has overlooked, and the item that comes promptly to mind is induced station blackout.

MR. MAYS: I guess the question I would have is who would have that level of knowledge outside of us or the plants to be able to conduct that kind of an in-depth review?

DR. POWERS: Another plant.

DR. WALLIS: Maybe that's right. Someone who's done it himself knows the ins and outs, knows the traps --

CHAIRMAN APOSTOLAKIS: Do you think that will contribute to public confidence to tell them that

San Onofre was reviewed by Diablo Canyon?

DR. POWERS: Well, I think if I was to formulate a panel, I would probably draw from a cross section of the community; that is, I would look to somebody with experience from the nuclear industry with a similar type plant, someone from academia, maybe even sophomore at Dartmouth. Well, they seem to be very knowledgeable individuals. And maybe somebody from the PRA specialist community. Budd Boyack's not a bad choice.

CHAIRMAN APOSTOLAKIS: I don't think that when you say that you appreciate the magnitude of this effort. I'm not against a review, but just to say, "Have these models reviewed," I mean we can start by reviewing SAPHIRE, for heaven's sake, and apply what you said earlier about the severe accident goes to SAPHIRE, which is the basis for the models. Let's do that first and then we can have a panel and so on. And then go to the individual SPAR models and make sure that we have a practical approach. That's all I'm saying. I mean just to ask, "Have you reviewed your 30 SPAR models," it seems to me is a little bit too much.

MR. BARANOWSKY: I'm Pat Baranowsky, Chief of the Operating Experience Risk Analysis Branch, and

I'd be glad to meet with the Subcommittee or the full Committee regarding SPAR models and whether there's adequate review or not. But I would like to point out that, as George Apostolakis said, these models have been evolving over a number of years, and there's a difference between SAPHIRE, which is the tool, if you will, and the model, which is the logic that reflects the way the plant's built. And as Steve said, the logic has been modified and is currently being looked at closely on each one of these models.

The assumptions that go into the models, for instance, how do model this sequence or that sequence and are they complete, are primarily based on the insights that we've derived from the IPEs and PRAs that are in existence and the accident sequence analysis work that we've done over the last 20 years. They're not meant to be models that uncover new accident sequences that nobody ever heard of before due to unique design or operational characteristics at a plant that aren't manifested in operating experience. That's supposed to be the purview of the licensee and other types of design and operational reviews.

So they have a different purpose, and that is to say if there's a new sequence and a contributor

that is unknown, I don't know that we would use the SPAR approach to try and find that kind of thing. It reflects what we understand today, our best understanding about what should be in risk models and a simplified version of them.

CHAIRMAN APOSTOLAKIS: And even more significant question, I think, is the level of detail that goes into the SPAR models. And I think the staff is still working on that in some sense anyway. You started with very simple models. Then you went to the next level. And I think as you use them for your purposes here, you will probably realize that we may do a little more here, a little more there. That's why I'm kind of reluctant to jump into expert panels and all that at this point. Although for SAPHIRE, I really think we should have a review, because it's a model, it's a tool, it's been out there for years now. It's the official PRA tool of the Agency. I mean we should have a serious peer review, and I think it can be done for a tool but for 30 SPAR models --

DR. SHACK: Well, I mean the question is if you're going to spend that kind of money, is this the way that you would spend it? I mean there are lots of things to spend money on.

CHAIRMAN APOSTOLAKIS: Exactly. Exactly.

MR. MAYS: Well, I know I kept control of the meeting at that point, so --

(Laughter.)

DR. WALLIS: Well, let me suggest, George, though, that I mean I think Dana's raised an important issue. It may not be the envisioned expert panel is the solution, but something to sort of ensure that the integrity and completeness of these things would be good. And I don't know what should be done, but --

CHAIRMAN APOSTOLAKIS: I did not object to the essence of their argument. I just thought that it was a little bit too soon to do that for the individual SPAR models. Let's do it for the tool first and then after you guys say, "Now we have the 70 models and this is what we're using them for," then it seems to me some sort of a review, not necessarily --

DR. POWERS: It seems to me you're begging to get into the situation of where we come back and say, "Well, these models really aren't what you really want, but since you've already built 70 of them, we might as well let you go ahead and do this."

MR. MAYS: I think it's a little more -- we may not have communicated as well, either through this document or through other briefings to you, the depth of what's going on with the SPAR model

development and what's been happening over time. We started out very early on in the Accident Sequence Precursor Program with just simple event trees, no-fault trees, fault probability numbers as an estimate of risk significance of events. We moved to models that had more detail in them in terms of the event trees that were more up to date with our current understanding of success criteria, as PRA evolved through 1150 and other things. And we have subsequently expanded that SPAR models and the Rev 3 down through fault trees to include support states, to include uncertainties explicitly in the analysis.

So we've made -- we had an outside panel in 1992, I believe, come in from all over the place, and George was a member of that working group in Annapolis where we said from people from industry and from academia and from the Agency, "What kind of models do we need? What characteristics do they have to have?" And so this SPAR model development has gone along that kind of a development path from the beginning.

And we also have internally to the Agency a SPAR models users group, which are the people who have to use risk understanding in doing their regulatory business, who are our users and our

customers who say, "These are the features we need. These are the characteristics it has to have. We've set out a standard in that group for how should we go about reviewing these models." So I think we may have a more substantial review process than is patently clear from this information.

And we agree that the models have to have a reasonable reflection of the risk characteristics of the plants for the purpose of what we're using here. Our external reviewers, including the industry, has told us they want to get the SPAR models and have a review of them, and we agree with that. And so I think we're on the same wavelength with respect to what needs to be done, and that is we should have SPAR models that are a reasonable representation of the plant. How specifically we go about doing them, I would propose we save for another day.

CHAIRMAN APOSTOLAKIS: At least until the ASME standard is approved. In fact, I hope that your guys on that joint committee that's developing the standard know that the Agency's models group is subjected to that standard. That's always a good check. So can we continue?

MR. BOYCE: All right. I'm on page 4. The first bullet there talks about two Commission

papers that NRR wrote that laid out the basis for our Revised Reactor Oversight Program in early 1999. And as you heard yesterday, we used both performance indicators and inspection findings to take regulatory -- to have regulatory engagement with our licensees. We ran a pilot program for six months in 1999, and we reported to the Commission the results of that pilot program in SECY-00-049.

And in the SECY paper, we said that while the future success of the Oversight Program was not predicated on the risk-based PI Program, that we thought that risk-based PIs would potentially support a couple of areas. And we said there are certain enhancements to our current oversight process where we thought risk-based PIs would help. Those are actually articulated in the last bullet. They're the reliability indicators, unavailability, shutdown and fire and containment indicators. And we also thought that plant-specific performance indicators would be useful in the future.

In order to make this happen, NRR wrote a user need letter to --

CHAIRMAN APOSTOLAKIS: Let me stop you right there, because that's something that has been bothering me for a long time. If you read -- I don't

know how anyone who reads Appendix F of the report of the staff issue in January can say that we don't need plant-specific performance indicators. And in fact the evidence there is so compelling that it seems to me that the current reactor oversight process, the revised process, risk-informed, has to immediately start looking again at the thresholds.

All I have to do is look at the tables that these ladies and gentlemen prepared, and I see things that if I use the industry variability curve as it is being used now, according to Appendix H of the revised oversight process, to get into the red for transient initiators, if I observe for three years, collect data for three years, I will need 646 transients. For loss of feedwater, to get into the red, I will need 355. To get into yellow, I will need 36. I don't know which utility or whether this Agency would tolerate 36 losses of feedwater in three years before it said, "Oh, now you're in yellow. We have to do something about it."

It's clear to me, and the mathematics shows it, that the thresholds we have now are no good. They're too generic. If I were running the reactor oversight process as it is now and I looked at this, I would make it my number priority to revisit the

thresholds. Now, tell me why I'm wrong.

MR. BOYCE: Well, it's important to remember that the purpose of the performance indicators is to help us establish the right threshold for regulatory engagement. I mean they're not definitive unto themselves. Just because you have a performance indicator does not mean that you should immediately shut down the plant. It means you should do further investigation to look at the causes.

DR. POWERS: It seems to me that he's asking the opposite question. Would you really tolerate 36 losses of feedwater in three years and not engage the licensee?

MR. BOYCE: Well, I mean, actually, I was trying to be supportive of the risk-based PI effort. It sounds like you're suggesting that risk-based PIs did not give you the correct indication.

CHAIRMAN APOSTOLAKIS: No. I was going the other way. The risk-based PIs are giving you an indication -- I don't know now; we have to review it more and so on -- but they are raising a flag that the thresholds you are using now are way off the mark, because they're generic. And for losses of heat sink, just as another example, to go to white, which is the very first level of alert, right, I will have to have

19.5 losses in three years.

DR. WALLIS: Which heat sink is that?

CHAIRMAN APOSTOLAKIS: What?

DR. WALLIS: Which heat sink is that?

CHAIRMAN APOSTOLAKIS: The ultimate heat sink.

PARTICIPANT: Condenser heat sink.

MR. MAYS: Let me help a little bit with that, George. One of the realities of looking at this from a risk perspective is that there are certain elements, whether they be initiating events or whether they be reliability, availability of particular equipment, that have relatively lower risk importance, and therefore in order to get to the pre-determined thresholds that we have, you have to have a lot of events.

And the other thing that's important to recognize is that all of those thresholds in the current ROP, as well as the thresholds that were in the initial draft Phase I report that you had from us, were based on having one variable out of all the variables in the risk analysis change enough to get to that threshold, while everything else at the plant remained at its baseline performance. And what you see is that for some elements the relative importance

of that particular element is such that if everything else stays at baseline, you really have to change that a lot to equate to that level of performance. That tells you something about relative risk.

It also tells you that since risk is really a multivariate function that you have a possibility of sometimes having thresholds that seem counterintuitive, because when you see the threshold the thought that, "Oh, and everything else had to stay at the same value in order to reach the threshold, which was the basis for that calculation," isn't really obvious to people.

And I think it's pretty clear that I would expect that before you got to 16 losses of heat sink in three years or 15 or ten, that the kinds of conditions that would be necessary to make that happen would also manifest themselves in other areas of the plant performance. And if we have a process that samples those other areas, you're going to see multiple areas starting to degrade, and that's what will get our attention rather than relying on the fact that loss of heat sink is the only thing that's going to change at this plant.

DR. POWERS: So what you're saying is we've defined the parameter incorrectly.

MR. MAYS: I'm saying the current reactor oversight process and the initial pieces that were in the risked-based performance indicator report were based on a concept which was we'll have a broad sample of performance, we'll see how bad each one of those individual pieces would have to get if everything else was nominal. That was the basic philosophy. And an implication of that philosophy is that the threshold set by that might seem counterintuitive because in real life there's more likelihood that you will see multiple things go wrong in that case than just one go really severely wrong.

CHAIRMAN APOSTOLAKIS: No, but -- no, no, no. I think Dana touched on the real issue here. I think either what Dana said is right, we defined them wrong, or the criteria that were used to derive these numbers and in the reactor oversight process were not the same, and in fact they were not, because you are using CDF changes, whereas they are using the generic plant-to-plant variability curve for each event.

MR. MAYS: Only for the green-to-white interface.

MR. BOYCE: For the white-to-yellow we used limited SPAR models.

CHAIRMAN APOSTOLAKIS: I know, I know, but

for the green-to-white there was a difference.

MR. MAYS: Correct.

CHAIRMAN APOSTOLAKIS: And this other thing that you mentioned, I don't know. I mean we are looking at individual indicators. I don't remember anybody making a presentation here that we are looking at the combination.

DR. KRESS: That's what the integrated performance indicator is supposed to do, isn't it?

MR. BOYCE: Right. That was in --

CHAIRMAN APOSTOLAKIS: Yes, but the indicators themselves were developed on an individual basis.

DR. KRESS: Yes. But they're going to integrate.

CHAIRMAN APOSTOLAKIS: Either these numbers make sense or they don't. We can't produce different results under different studies and then say, "Well, but the other results were okay too." It seems to me that you make a very good case in Appendix F that these things have to be plant-specific. You say that clearly when it comes to unavailability. The observability over diesel generators on reliability varied greatly across the industry, from 2.5 tenths to the minus four for BWR Plant 3 to 2.9 tenths to the

minus two.

Similarly, for RCIC unavailability, and there you say, "Weak examination of data for other systems revealed similar variation among units. Therefore, we decided that only site-specific data were appropriate for estimating the variability of outage data at the plant." Now, if I read this and I was running the reactor oversight process, wouldn't I worry? Wouldn't I say, "Am I doing the right thing?"

MR. BOYCE: Yes.

MR. MAYS: George, let me help a little bit on that too.

MR. BOYCE: Yes, I agree with you. In fact, that's what we said. We thought that plant-specific PIs were the way to go. I mean we said that.

CHAIRMAN APOSTOLAKIS: And what I'm saying is there is a higher degree of urgency to this than just saying, "We'll wait until Mays is done and then take the results."

MR. BOYCE: There are other problems.

CHAIRMAN APOSTOLAKIS: Because this tells me that -- well, this gentleman has been trying to talk for a while now.

MR. HOUGHTON: I'm sorry. Tom Houghton, NEI. Good afternoon. I thought I heard you say --

and perhaps I was wrong -- I thought I heard you say that the current program has a very high number of loss of heat removal scrams for the green/white indicator. The indicator is two. You can have two in three years is all you can have for the green/white.

CHAIRMAN APOSTOLAKIS: I understand.

MR. HOUGHTON: It's not a higher number than that.

CHAIRMAN APOSTOLAKIS: No, no, no. The numbers are quoted from here. I didn't mean that.

MR. HOUGHTON: Okay.

CHAIRMAN APOSTOLAKIS: But what I'm saying -- let me emphasize what I'm saying. I'm not prepared to claim that the numbers we're using now are no good. No, actually I am.

(Laughter.)

But the numbers we're using now -- no, no. I think I should rephrase this. I'm not prepared to say that. What I'm saying is that there is sufficient evidence from the analysis that is presented in Appendix F of this report to convince me that we really need plant-specific indicators, plant-specific thresholds, and that we should make a much more careful study, do much more careful study of the observation time and the actual thresholds, of course,

using methods similar to Appendix F to make sure that we have covered these uncertainties, which are aleatory and epistemic because now you are really dealing with the real world, and increased public confidence or at least my confidence that what we're doing is really rational.

So I guess the reason I -- I guess -- I don't guess. The reason why I'm raising this is because I think it's of a certain urgency for the existing revised reactor oversight process. It's not something that can wait until you guys are done. You guys means research.

MR. MAYS: There are two issues that kind of got woven up here together. One of them had to do with the fact that you can have some fairly high numbers for certain -- to get to certain thresholds, notably yellow and red, that seem to be counterintuitive because the idea is if you had anywhere near that number of events, something else would have -- we would have been doing them. And I agree that that's a separate thing, and it has to do with the nature of having single variate analysis in a multivariate picture and the relative risk importance.

The second point you made was about the

plant-specific nature. Now, one of the things we had in the discussion here on verification and validation is we went back and looked at how the plant-specific data and information we had would compare with the similar kinds of indicators and information in the current reactor oversight process. So to give you a little more -- maybe a little feeling of a little more ease, we didn't find substantial differences in the overall assessment of things between the risked-based performance indicators and the Reactor Oversight Program.

CHAIRMAN APOSTOLAKIS: And why do you say that?

MR. MAYS: There will be -- in the verification and validation section we talk about that.

CHAIRMAN APOSTOLAKIS: Chapter 5 of the main report.

MR. MAYS: What we did find was that there were differences. Sometimes they were -- the risked-based performance indicators indicated that performance was worse than indicated in a similar version of the reactor oversight process, and sometimes they indicated they were better. And when we get to the section where we discuss the alternate

ways of looking at RBPIs, in light of the comment of how many we had, you'll see that the more integrated approach that we took in this alternative section helps to address both of those issues.

CHAIRMAN APOSTOLAKIS: You know what the integrated approach is? Take the PRA of the plant, look at the initiating event number they have, look at the unavailability of the system, because they have already done it. And say, "For this number I don't want this deviation, I don't want that deviation," and then you have the integrated view. You don't have to do anything; the PRA had done it for you.

DR. KRESS: Your threshold would be delta CDF --

CHAIRMAN APOSTOLAKIS: Exactly.

MR. MAYS: That's exactly what we --

CHAIRMAN APOSTOLAKIS: And also it will be --

MR. MAYS: That's exactly what we did in the alternate approach here, George, is we used the entire model, and depending on whether we were looking at the cornerstone level or whether we were looking at a functional level on systems or a response to --

CHAIRMAN APOSTOLAKIS: That's not what you do in Appendix F.

MR. MAYS: That's not in Appendix F. That's the alternative stuff that we presented at the Subcommittee last month. The stuff we're going to present --

CHAIRMAN APOSTOLAKIS: The ultimate result of all this is take the PRA, which comes back to my favorite subject of objectives. See, as you read the -- I'll ask you questions. I'm just talking to NRR because they are here, but your turn will come.

But the objectives, the objectives are extremely important, because you're playing there with prior distributions. Appendix F was written by a statistician, I think. He says, "Well, this number doesn't make sense, so I'll use another prior." You'll use another prior because the numbers don't make sense? Perhaps you should be shot first.

MR. MAYS: Well, actually, that's not what we did, but that's --

CHAIRMAN APOSTOLAKIS: That's what it says. I can only go by what it says.

MR. MAYS: Well, actually, that's a different characterization than I would put on it.

CHAIRMAN APOSTOLAKIS: My point is plant-specific PRA, plant-specific thresholds make much more sense than anything else, and it's your work to date

-- I appreciate your valiant efforts to defend your colleagues -- but your work to date makes that urgent, in my view.

DR. KRESS: And why have thresholds on individual performance indicators?

CHAIRMAN APOSTOLAKIS: Well, they went to trains, which is very good. We'll come to that if we ever come to that. I mean they did some good stuff there.

DR. KRESS: That would help, but why not integrate it all at once?

CHAIRMAN APOSTOLAKIS: At some point.

DR. KRESS: It says suppose you're using the PRA and plant-specific.

CHAIRMAN APOSTOLAKIS: Well, there are two competing --

DR. KRESS: Call Bob Christie and say, "Let's say the performance indicator on delta CDF."

PARTICIPANT: Is Christie here?

CHAIRMAN APOSTOLAKIS: No, no, no, no, no. There are two competing --

MR. MAYS: He was, but he got scared and left.

(Laughter.)

CHAIRMAN APOSTOLAKIS: -- elements here:

One is to be as high as you can, as you say, to go the Christie way, and the other counter argument is that you want something you can observe. So you have to go -- that pulls you down, the other thing pulls you up, and you have to --

DR. KRESS: No, no. But you're observing the things that go into the PRA to make the delta CDF calculation.

CHAIRMAN APOSTOLAKIS: Yes. And that's what these guys are doing. And then they come back and they tell you --

DR. KRESS: Yes, but don't put the threshold on those, because they're determined, just like he said, as if all of them say the same except that one. Just look at all of them and integrate the total change and see the effect on delta CDF and put a threshold there, rather than have individual colors for each PI.

CHAIRMAN APOSTOLAKIS: In an ideal world, that's the way it should be done. You are asking the Agency to take a gigantic step away from micromanaging all the way out, and they will never do that. So let's hope that they will go to the trains that these guys are offering now, and then maybe later -- because, remember, we're going to discuss option two

a little later.

MR. BOYCE: I'm on page 5 now.

(Laughter.)

Actually, I mean, we're challenged as to why we just don't do it immediately. And that giant step forward is, I mean, really what we're facing here. And we think that there's certain key implementation issues that need to be looked at before we go and take that giant leap forward or if we take that giant leap forward.

And the ones that we've already discussed, data quality and availability, SPAR model development, and V&V. The V&V that I'm referring to was -- it's not enough that we developed the SPAR models, we need some way to gain what we were looking at was acceptance by the licensees and the public, that the SPAR models were going to give you a reasonable answer. And we weren't saying a perfect answer, that we modeled all possible events and all possible scenarios; we were just saying a reasonable answer with which we could regulate. So I think we had identified these issues. They're in Section 5 of the Phase I report. And I won't go into more of that.

I did want to make one more comment on data quality and availability. The reliability data

is coming from a database that is called EPIX. It's run -- that database, I think, is collected by INPO, and it's the successor to NPRDS. And it was in response an AEOD initiative for a reliability data rulemaking, and industry said they would stand up EPIX and populate it in lieu of that data rule. And that was about 1997 time frame.

And industry has in fact followed through on that effort, but it's still a voluntary initiative. We don't have a requirement. There's no rulemaking that says anybody needs to submit data. Even the current reactor oversight process is still voluntary submission of data. And we haven't taken a close look at the EPIX database to say that there is 100 percent participation in submission of data. We haven't said that there is consistency in terms of submission of that data. And we haven't done verification of that data.

CHAIRMAN APOSTOLAKIS: Where would you get your data? The current process, where does it get its data?

MR. BOYCE: The reactor oversight process is submitted directly from licensees to the NRC on a voluntary basis.

CHAIRMAN APOSTOLAKIS: And why can't I do

that with risked-based performance indicators? Remember, I am not advocating generic numbers, so I don't need to have assurance of the whole of industry in submitting data. I will do it on a plant-specific basis.

MR. BOYCE: It does go back to acceptance. I mean industry -- we worked very closely with industry in order to get where we are today on the current reactor oversight process. Industry has already publicly stated that if we add -- I think we're looking at an additional 30 performance indicators, that they may not accept that on a voluntary basis, because it's a huge additional burden, and it opens up the potential that if you have more performance indicators, you'll have more opportunities across thresholds, you'll get more regulatory attention. And they want to understand is it really warranted? And we've heard that -- I think you heard that at the Subcommittee meeting, and we've heard that at public meetings.

And so we are working through these sorts of issues, and that's implementation. And it's got to be acceptable to all parties in order for this to work correctly. They own the data, they need to help with the models and make sure they're right, and it's got

to be a cooperative effort.

CHAIRMAN APOSTOLAKIS: Okay. Now, again, for me that's a non-issue, and let me tell you why. This is a plant-specific issue, and this Agency has already done similar things on a plant-specific basis. But the Maintenance Rule, I didn't hear anybody complain about data at that time. You asked the licensee, "Tell us what the threshold should be," and there is a rule out there, and we're using it. Why can't we do the same for the oversight process? "Mr. Licensee, tell us in the integrated model, for initiating for this and that, what would be the thresholds?" And, of course, we look at them, we study them, we create an Appendix F, blah, blah, and then eventually we agree. We've done it for the Maintenance Rule. What's so difficult with this?

MR. BOYCE: I guess you need to weigh the costs and benefits. When you go to the Office of OMB and we need to justify that the benefits would exceed the costs.

CHAIRMAN APOSTOLAKIS: Okay.

MR. BOYCE: I mean that's one bureaucratic hurdle.

CHAIRMAN APOSTOLAKIS: I understand that, but at the same time this is hailed as a -- the

revised process is hailed as the major regulatory change of the last 20 years. But I don't want to elaborate the point too much.

There is one other major issue that I think has not been addressed, neither by this project nor by the revised oversight process. And because it has not been addressed, we see a lot of problems here and reaction from NEI. It seems to me that somebody should study the tradeoffs between using a performance indicator and baseline inspection. The way we appear to be handling this is we are looking at the performance indicators. Now these guys come up with a total of 30 or so. The industry says immediately, "Wait a minute now. How many are we going to have?" Because the industry doesn't see on the same piece of paper we're going to have these indicators, and we will relax the Baseline Inspection Program in these areas, because these areas are covered by the indicators. As long as you don't see that tradeoff, you will have these objections all the time.

So it seems to me that's a high-level issue of equal importance as the previous one, but I think both, maybe this project and most importantly the people who run the oversight process, they should address, because otherwise we'll have this perennial

problem. We have one transit indicator. Now you want to make them four, I think, or some three or four. Why? What kind of tradeoff is that? You're just increasing the burden.

MR. BOYCE: I think philosophically we agree with you. We would like to say that our revised reactor oversight process was in fact a significant step in that direction. When we took a look at going from our Core Inspection Program to our Baseline Inspection Program, we did exactly that sort of approach, conceptually. We took the best data that we had available at the time, and we said this is the sort of PIs that we can get insights on a specific area of plant performance, and we don't need to do additional inspection in that area. I think you know that -- I mean that effort was limited, but we're pragmatists here. We're getting to that point, and we can't expect perfection on the first try.

The risk-based PI report, as you also know, laid out a systematic approach to here are the accident sequences, here's the data you can collect for performance indicators, here's the data you can collect on an industry-wide level, and here's the gaps that could be covered by inspection. And you brought that up at the Subcommittee. We think that sort of

approach has got merit. We would like to see the effort move to be more mature and gain greater acceptance before we say, "Okay, let's charge forward."

But in the meantime we have done a separate effort where we're taking the significant risk insights from various studies such as the Initiating Events study, and research has provided that to our inspectors and is providing those sorts of insights to the Inspection Program Branch, and we're attempting to incorporate those significant insights into our current inspection procedures. It's not perfect, but at least it's a step in the sort of direction that you're alluding to.

CHAIRMAN APOSTOLAKIS: Now, Steve, I understand it's not part of your charge to look at these tradeoffs. You're just looking at the feasibility of having certain indicators, right?

MR. MAYS: That's correct. We were looking at what could be technically feasible using, basically, off-the-shelf and readily available models, tools, and data. And I think we should point out that the Reactor Oversight Program has, as an integral part of it, a change process where proposals to change the indicators and the reactor oversight process can go

through. And that process involves meetings with internal and external stakeholders, understanding of what the implications of the information is, and an opportunity to look at what the potential costs or benefits are as part of the reactor oversight process change process. We've only gone through a couple of different things in the oversight process from that standpoint, but I do think we have a mechanism for doing that.

So I believe what we raised in the report was based on our understanding of the models, methods, and data and where this would potentially fit in the oversight process. We said these are what we think are the key implementation issues. And from our discussions with internal and external stakeholders, we've got pretty good agreement that those really are the issues and that the process for dealing with those issues is through the ROP change process.

CHAIRMAN APOSTOLAKIS: Maybe there is a process, but I think the process does not emphasize enough that within the process we are doing these -- we are making these tradeoffs between baseline inspection and performance indicator in a systematic way. Because otherwise, if everything is so good, why is industry complaining that you are trying here to

increase the burden? Surely, they must know what the process is all about.

But I think we're running out of time here, so can you tell us what the real message you want to send us is by summarizing your --

MR. BOYCE: I think that NRR is cautiously supportive of the Risk-Based PI Program. We would like to try and engage industry further to resolve their comments on burden using the technical merits of this product and perhaps taking a look at our inspection practices to see if there's some solution to those. And we'd like to try and keep moving forward with this effort. We've endorsed it in a user need letter, and we'd like to see the results.

I think that right now the comment period on the Phase I report expires on the 14th of May, and we're going to take a look at the comments that we get and try and deal with them. And I think the schedule for issuing this Phase I report is November time frame. So we hope to address some of those issues between now and then.

MR. LEITCH: I have a question about the unplanned power change indicator that's in the ROP now. And my question is not so much about the definition, and I understand that may be up for

reconsideration, the precise definition of that. But that kind of information, unplanned power change, seems to me to be a valuable indicator, and I understand that it doesn't really have any linkage to risk. In other words, the risk-based -- that kind of an indicator would not be in a Risk-Based PI Program.

And my question, basically, is if we go to risk-based, is the thought that we have to be all risk-based? In other words, would an indicator such as that necessarily fall by the wayside?

MR. BOYCE: That goes back to the earlier question I think we had on the thresholds for certain of the indicators and why we have particular indicators. When you get to the pragmatics of regulating, you end up doing some things that are not, say, fully consistent with risk techniques, like the scram indicator. Scrams you can tolerate, I don't know, 25 on a plant before you get past ten to the minus six CDF. And yet we have found by comparing the scram indicator to what used to be our definition of problems plants -- the watch list and near-watch list type of plants -- there was a fairly good correlation between plants that had a high number of scrams and plants we thought were problem plants.

And so in terms of regulatory engagement,

we found the scram indicator to be a very useful indicator. So I can't prejudge a decision as to where we would be, but we think we would probably continue that scram indicator for that reason. And we think that risk-based PIs could be an enhancement to our current set of indicators, perhaps replacements for many, but we would retain certain ones because they other insights beyond pure risk.

MR. LEITCH: And the power changes made could very well be one of those?

MR. BOYCE: It could be. I don't want to get ahead of the problem, but it could be. All right. I'll turn it over to Steve on page 6.

MR. MAYS: In light of the fact that we now have about 40 minutes left for the section we expected to take between five and ten minutes in the initial phase, I think we may need to address an abbreviated version even of what we have here. If it's suitable to you, George, I would like to skip down to the sections that you asked at the Subcommittee that we specifically go to, which means I will skip over the information about the potential benefits and our development process. And I want to go first to the table, which is on your page 8 and give you a flavor of what we had from the draft Phase

I report and then move into the specifics of what we had in those areas you asked us to spend more time on.

This table shows what's in the existing Reactor Oversight Program as PIs and what areas through our development and work we've determined as proposed risked-based performance indicators. We went over in greater detail the derivation of these in the Phase I report with the Subcommittee, so we've only put a summary of what that information is here. This shows that the RBPIs cover more and often different aspects of the impacts of performance on plant-specific risk. And we'll show you some more specific results and calculations in the V&V discussion. You'll note that there are a couple of asterisks on this chart that indicate potential performance indicators that we either didn't have all the models, data or capability to put together PIs right now, although we think they might be something we could od in the future.

CHAIRMAN APOSTOLAKIS: Now what you're saying with this table, Steve, the way I understand from the discussion so far, is that, yes, the Risked-Based Performance Indicators Program identify more potential indicators for mitigating systems, for example. But you are not necessarily advocating that

these be adopted. You are saying these are feasible. And it's another decision whether, you know, we want to use all of them, what to do with the baseline inspection, and so on.

MR. MAYS: That's correct.

CHAIRMAN APOSTOLAKIS: That's the way I see it.

MR. MAYS: That's correct.

CHAIRMAN APOSTOLAKIS: Okay.

MR. MAYS: A notable thing also that we want to bring your attention to is we had been asked by NRR in their user need letter, as I mentioned before, to see what we could do to come up with indicators for shutdown, fire, and containment areas. And we're going to talk about what we came up with for shutdown. We were unable to produce performance indicators for fire and containment because of either lack of models or lack of available data.

We have three things we need to develop a risked-based performance indicator for potential use. The first one is a model that reasonable reflects the risk, and the key word there is reasonable; not perfect but reasonable. The second one is we have to have baseline performance data to put into the model so that we can vary that through sensitivity analysis

to see where the threshold should be set. And the third thing we need is an ongoing source of data to compare that performance to the thresholds.

In the case of fire and containments, we were lacking in both models and data. In the case of shutdown, we were able to find models and a baseline performance and information to potentially use the PIs. But also in the shutdown, we're not currently gathering the data right now, but it's something we believe is potentially able to be done relatively easily. So we've gone ahead with the shutdown performance indicators to discuss those.

CHAIRMAN APOSTOLAKIS: So you're not necessarily saying that a shutdown PRA is better than the fire PRA.

MR. MAYS: Correct. I'm not saying that.

CHAIRMAN APOSTOLAKIS: I think you have a question coming from somewhere there, no?

DR. POWERS: Can I ask a question about your Mark I containment spread?

MR. MAYS: Sure.

DR. POWERS: Correct me if I'm wrong, but I believe that containment spread of Mark I is connected also to the low-pressure injection system.

MR. MAYS: That's correct.

DR. POWERS: And most of the Mark I containments have blanked out the containment spread; it's non-operational.

MR. MAYS: I'm not --

DR. POWERS: It requires a manual change to make it active.

MR. MAYS: Not that I'm aware of.

MR. HAMZEHEE: I don't think we noticed that in our work.

DR. POWERS: I could be wrong about that.

MR. MAYS: Not that I'm aware of.

DR. POWERS: I don't think I'm wrong but I could be.

MR. MAYS: I believe they're manually initiated, but I don't believe they're -- I don't think they have an automatic set point where they come on, but I believe that they are still capable and functional in the systems.

MR. LEITCH: They're operated from the control room. It requires manual actuation from the control room.

MR. MAYS: In the area of shutdown for performance indicators, the Subcommittee asked us to spend a little time on that. The process we used here is a different approach slightly from what we did with

the other types of indicators that you've seen, either in the ROP or in the other parts of the RBPI report in that this indicator is more a measure of the impact of configurations during a small period of time, the outage, as opposed to an accumulation of performance data over time, such as the reliability of a pump or the frequency of an event that you would track over time and history and be able to trend.

This has been linked more towards a SDP type analysis of conditions than the standard classical indicator definition, and we recognize that that's the case.

Let's go to the next page here. The key in this process was the acknowledgment that there are certain necessary combinations of decay heat, reactor coolant system inventory, and equipment availability the utility must go through in order to conduct a refueling outage. So we wanted to be able to take into account that that was something that was a necessary part of operations. It had some risk associated with it. And if we were going to make performance indicators associated with shutdown operations, we had to allow that particular portion of the risk to be there without penalty.

So the baseline risk was taken into

consideration. We looked at shutdown PRAs. We looked at information about plants and how long they were spending in various conditions in shutdown. And we took that indication in the baseline information that's on these tables for BWR and PWR.

Then we looked and said how much time would somebody spend in categories of high, low, medium or early reduced-inventory vented conditions that would result in accumulation of risk in addition to that baseline. And we set the thresholds according to that to be consistent with the ROP thresholds of ten to the minus four, ten to the minus five, and ten to the minus six delta CDF associated with being in performance areas outside the norm.

DR. KRESS: If the containment is compromised during that same period, why should you use those same deltas as your criteria? Shouldn't you have a more stringent delta?

MR. MAYS: The issue of containment was one where our problem is model availability to be able to assess what the risk implications and set thresholds are with respect to that. We're basically going off of core damage frequency here, because that's what we have the readily available models to do.

DR. KRESS: But I would have thought you might have gone a little more severe in the thresholds for those.

MR. MAYS: The problem we faced there was --

DR. KRESS: Maybe five or ten.

MR. MAYS: What?

DR. KRESS: Maybe five or ten.

MR. MAYS: Maybe. The problem there is it was, again, what factor do you use and what's your basis for saying that that particular factor has an implication to public risk. And we just were not capable of doing that in this particular analysis. I don't disagree, because we said in the report that having containment models for both at-power and shutdown conditions would give us the ability to determine what the impacts were on those, which we're not able to do now.

So what we have here is baseline information. And then on the next two slides what we have is examples of configurations associated with specific times, decay heats, and RCS conditions that a plant might be in during a shutdown outage.

CHAIRMAN APOSTOLAKIS: So your indicator here is the time the plant spends in that state?

MR. MAYS: That's correct. So what we would do, for example, is you'll have examples on this table where if you have a diesel generator out under a certain set of conditions, the table will tell you whether that's a low, medium, high or a nothing in terms of how much you need to accumulate. So you would accumulate all the time you spent in those conditions under the low, add them all up and see if that exceeded the threshold. You do a similar thing for medium, a similar thing for high.

Now, there is one special case we have here, which is called the early reduced-inventory vented condition, which in order to do shutdowns plants are often having to go into mid-loop, install nozzle dams, do other kinds of things to conduct their outages. Early on in the regulatory business, there was a shutdown rulemaking effort that was underway. There was an agreement made that there would be a process by which the industry would put together a set of standards for dealing, for how they would conduct outages under those conditions.

So this indicator that we've proposed here recognizes that condition and says, "If you are conducting early reduced-inventory vented conditions in accordance with the, I believe it was NUMARC 9106

guidance for shutdown configuration control, that we would set our thresholds assuming that you had those configurations met. If you're not in those configurations in accordance with that document, you would automatically transfer into the high category under this scheme, which is a more severe and more limiting setup.

So we're trying to give appropriate credit for the baseline of what you have to do to get into a shutdown and refueling. And then indicate if you've done performance issues that exceed that, what their potential risk significance is. And so we also have another slide here which gives the BWR corresponding conditions for that.

CHAIRMAN APOSTOLAKIS: Now these times are the cumulative times over a period.

MR. MAYS: The cumulative times over the refueling outage. So, for example, if you're a plant operating state 4, hot shutdown with the RCS boundary in tact, and you had a diesel generator out of service for a certain time, that would be a low in this chart. So you'd add up that time. And any other low times that you were in during that outage would all be counted together, and you compare that to the thresholds on the previous page to see whether you had

exceeded the threshold or not. And if you're in an area of operation where it's a blank cell, you can be in that as much time as you want.

And, again, the industry commented during our public meeting that we had the week after the ACRS Subcommittee that they believed this tool was probably more appropriate to use as a significance determination process type of tool rather than a performance indicator type tool. In other words, you would use this tool to determine after the fact, if a plant was in a certain outage condition, whether that outage condition was really important or not.

CHAIRMAN APOSTOLAKIS: But it seems to me that in order to go to the SDP, some sort of deviation from something has to be observed. What is that something in this case? If you don't have an indicator and a threshold, why would you even enter the SDP?

MR. MAYS: Well, the issue there would be is this somebody's had discovered as part of their outage, for example, that they had had equipment out of service, like two diesel generators, when they weren't planning on it originally. And you would go back into something like this process and say, "Well, what was the risk associated with being in that

condition for however long you were in it? What were the RCS conditions and the decay heat conditions when you were in that?" And you would make an assessment based on this kind of an approach.

CHAIRMAN APOSTOLAKIS: I guess I don't understand how you would decide to make the assessment. Don't you have to deviate from something?

MR. MAYS: I agree you do --

CHAIRMAN APOSTOLAKIS: The SDP says -- I mean the examples we heard yesterday were they forgot to do a test. They're supposed to do a test; they didn't do it.

MR. MAYS: Yes. Right.

CHAIRMAN APOSTOLAKIS: So that's sort of a violation of some sort.

MR. MAYS: Right.

CHAIRMAN APOSTOLAKIS: So now you enter the SDP or in another instance what did they do? There was something else. But if it's something they're supposed to do and they didn't do it, then I go to SDP. If I don't have an indicator here, what is that something that will make me go to the SDP?

MR. MAYS: I'm not aware of what that would be.

MR. BARANOWSKY: This is Pat Baranowsky

again. Are you done, Dr. Kress? Am I interrupting?

DR. KRESS: Go ahead.

MR. BARANOWSKY: What I was going to say is that remember the industry is committed to following certain guidelines during shutdown. And one of the things we do in inspections and verify that they've followed those things. So as part of the inspection they might verify that they were operating in accordance with those guidelines, which could then be fed into this model, if you will, to assess the findings associated with that.

CHAIRMAN APOSTOLAKIS: So the point is that one way or another you have to have some sort of --

MR. BARANOWSKY: Yes. There has to be a way to get in there, but I believe there is a way. Maybe Tom Houghton could help me.

MR. HOUGHTON: Yes. You have to have a performance issue, meaning either you have some event or occurrence or you have some violation or behavior which is viewed as suspicious in some way. If you're not following a procedure, you're committing a violation, and that procedure's significance, that violation could be assessed using this process. Is that helpful to you?

CHAIRMAN APOSTOLAKIS: That could be, could be.

MR. HOUGHTON: Yes. I mean if you viewed -- if you looked and there was a tech spec violation in terms of having RHR capability, you could use this process to determine what the risk impact of that was and put it in perspective.

CHAIRMAN APOSTOLAKIS: It seems to me, though, the industry should be arguing the other way, because this already allows you some, quote, "violation" without anything happening. Now you're saying, no, I will have the procedures. If I deviate a little bit, I will have to go through the whole process, which doesn't make sense to me. Because this already has built into it what's allowed. So I don't have to do anything else.

MR. HOUGHTON: Well, I think it's a little different than what's allowed, because, for instance, there's not a limit on mid-loop operation. However, if you look at the thresholds built into this, one might find oneself crossing a threshold when you're doing the perfectly right thing, which is if you're having a problem, not to rush through to keep the hours under two hours. And in fact the most difficult time -- the most risky time is going in or coming out

of the mid-loop. So here I am. I'm approaching, the clock's ticking off. I've about reached the threshold. Two more hours I go into a yellow threshold when I really should be stopping all work and saying, "Let's find out what's wrong. Let's plan and do it correctly." So that's part of the concern about the --

CHAIRMAN APOSTOLAKIS: You are really discouraging people from doing the cautious thing.

MR. HOUGHTON: It may or may not, and we need to look at that more carefully.

CHAIRMAN APOSTOLAKIS: No, that's a very valid point, I think. Which brings me to my other favorite topic. This implies that what really controls the risk here is the time of -- the duration. I don't like that. Because that means that no matter how high the risk is during that time, as long as the exposure is short, we're okay.

DR. KRESS: Well, wait a minute, George.

CHAIRMAN APOSTOLAKIS: I know.

(Laughter.)

DR. KRESS: And you're a PRA guy.

CHAIRMAN APOSTOLAKIS: I know. You and I have disagreed about this in the past. I don't see why we can't disagree today.

DR. KRESS: Yes, okay.

DR. POWERS: Well, I guess the point I would appreciate a little advice on is the summation of hours. I mean if I enter a medium configuration for two hours and then I come out of it, go along and I find I have to go back in to it, why should I sum that previous two hours? I escaped scott-free there. Why shouldn't it be the continuous period that I'm in there that gets evaluated?

MR. MAYS: Well, I think the answer is that this -- if you're in for two hours and you come out and you go back in for two hours, we're measuring the accumulation of risk that you've incurred over this outage. So what we're doing is saying over this outage the accumulation of risk you have incurred by being in these states which have relatively high risk significance is what we want to know. We don't want to -- you know, the idea then, if you --

DR. POWERS: I think I understand what you're doing.

MR. MAYS: If you didn't have that philosophy, then you could be in the high risk thing for up to one hour before you get to threshold, back out, come back in for a few minutes, go back up to it again, and you would just never be there. And, in

effect, you would have been there the whole time.

DR. KRESS: Well, what bothers me about that is -- I think it's a reasonable thing, but what bothers me is how do you add high and low and medium together?

MR. MAYS: Well, that's the thing we haven't done here, we haven't done here.

DR. KRESS: Yes, I know. By the same concept, it has to be done some way. So that's the one that bothers me about it.

CHAIRMAN APOSTOLAKIS: Why do you have to add high and low?

DR. KRESS: Because they represent the cumulative risk.

MR. MAYS: That would be the cumulative impact of the entire thing.

DR. KRESS: You can't just add the times.

CHAIRMAN APOSTOLAKIS: That's what I'm saying, but why would you have to add them?

DR. SHACK: Well, he says he's interested --

DR. KRESS: He's accumulating risk. You've got to accumulate off of this.

CHAIRMAN APOSTOLAKIS: But I thought it was cumulative for each category.

MR. MAYS: It is cumulative for each category.

CHAIRMAN APOSTOLAKIS: Not in total.

DR. KRESS: Yes, but that doesn't make sense.

MR. MAYS: Dr. Kress is raising the question as if I am in the white for my low and the white for my medium and the white for my high, what's the net total effect?

DR. KRESS: Are you not in red overall?

MR. MAYS: And I haven't gone to the further step of accumulating that all together, although that could be done.

CHAIRMAN APOSTOLAKIS: Isn't that an issue for the Action Matrix?

MR. MAYS: That's the way we set it up to do it here, but that's another thing where we could, as we're doing the alternate approach, we could potentially accumulate them all together as well.

MR. HAMZEHEE: We have the same thing for at-power situations. We don't have an accumulative impact measurement right now except the Action Matrix. So you have the same situation.

DR. KRESS: Yes, you would, absolutely.

CHAIRMAN APOSTOLAKIS: When it doubt, give

it to the Panel.

MR. MAYS: Okay. The next thing we wanted to talk about was the work associated with how much risk coverage do we have with these RBPIs and what's the verification and validation that we've done? What I want to do here is indicate that we have gone back and looked at this from two different standpoints: One from kind of a false vessel approach, one from a risk achievement worth kind of approach.

And I'd like to put up the next slide, which shows one of the comments that was made earlier about how do you use risked-based performance indicators versus risk-informed baseline inspection? So what we did and what's in the report for all the 23 plants that were in the Phase I report is we went back and we went through the IPE database, which was compiled after all the IPEs were put together, as to what the dominant sequences were at the various plants.

And what we have in this graphic display is we have a box around all of the areas that are part of the dominant sequences in the IPE database where we either have a risked-based performance indicator, we either have an industry trending information or we have an initiating event indicator.

And what you can see fairly quickly just from looking at this is there aren't very many dominant sequences for which we don't have some multiple way of looking at what the performance of the plant has been with respect to dominant sequences.

The other thing that it also tells you is the areas in the dominant sequences for which we don't either a mitigating system indicator or an initiating event indicator or an industry trend are areas that we should be covering in a risk-informed baseline program.

So to answer you earlier question, although it's not on this particular chart, you could potentially go into this and say, "Okay. If I've got these things covered by indicators, what are the things I should have in my Risk-Informed Baseline Inspection Program? I think that's one of the valuable things that this particular program has done is to make that more clear from a risk perspective what those particular areas should be.

CHAIRMAN APOSTOLAKIS: And I still have the issue, though, that you raised, which is, is it really fair -- maybe you didn't put it in the same words -- but is it really fair or reasonable to take, say, the first box there, TRX, okay, number 8,

sequence number -- no, eight is no good. Tell me what the sequence means. I can start with a TRX and then I have the HPCT? Is that what that means?

MR. MAYS: This was a sequence where you had a transient and you had failure of the automatic depressurization --

CHAIRMAN APOSTOLAKIS: Oh, okay.

MR. MAYS: -- and failure of DC power.

CHAIRMAN APOSTOLAKIS: And for these I can or cannot have --

MR. MAYS: I don't have risked-based performance indicators for those. So those will be areas that should be covered for that particular function through the Risk-Informed Inspection Program.

CHAIRMAN APOSTOLAKIS: The baseline.

MR. MAYS: Right.

CHAIRMAN APOSTOLAKIS: So you are addressing that issue now here, the tradeoffs. Very good. But let's look at number 23 where I have the same transient, but now you're telling us with the boxes that I can have indicators for the two mitigating systems, right, RCIC and HPCT.

MR. MAYS: That's correct. And the reason this one was --

CHAIRMAN APOSTOLAKIS: Now, wait a minute.

Let me finish my thought.

MR. MAYS: Okay.

CHAIRMAN APOSTOLAKIS: So now when I set my indicator here, my thresholds, I should take into account, I think, in some way the fact -- I mean is it reasonable to set the threshold in such a way that TRX alone, its frequency, should trigger a ten to the minus five or six change in CDF? I thought you were arguing earlier that doesn't make sense. You shouldn't do it one at a time.

MR. MAYS: What we did was we had -- when we, in the Phase I report, looked at, for example, the HPCI train reliability, we said if the HPCI train reliability changes and everything else stays the same for all the sequences, what would be the change in CDF associated with that? So it wasn't just associated with TRX; it was associated with all the sequences for which HPCI would be affected. However, it assumes that RCIC, the transient frequency, the LOCA frequency, the diesel generator reliability are all at their nominal values.

CHAIRMAN APOSTOLAKIS: So I thought you meant something else then. But I think using the plant-specific PRA, I can work with these things and define the indicators at an appropriate level so that

I take advantage of these indications that I have now. I'm not prepared myself now to tell you how to do that, but I think that's a good thought.

In other words, on the one hand, as we said earlier, the PIs should be as high as possible on the PRA where the CDF is at the top, okay? And I will try to do that as much as I can with the sequence. On the other hand, I have this issue of having to observe some data, which pulls me down, okay?

DR. KRESS: You're going to have a really tough time there, George, because what these PIs are is a sample --

CHAIRMAN APOSTOLAKIS: That's correct.

DR. KRESS: -- of things that are part of the PRA. And you're sampling a limited -- it's a limited sample, and you're going to look at the degradation of all of them, and some of them may have improved, actually. But what you're going to try to do is now infer from that what the total plant change has been on all the things that affect the PRA results. That algorithm doesn't exist, and that's the problem right here. And I don't think you can set individual thresholds on these things without that algorithm, and that's my problem.

CHAIRMAN APOSTOLAKIS: Okay. But maybe

there is another way out of this.

DR. KRESS: The other way out of it is to use the Bob Christie -- here is here now.

CHAIRMAN APOSTOLAKIS: No. Christie is only one element of this.

DR. KRESS: And set the threshold on delta CDF itself.

CHAIRMAN APOSTOLAKIS: No, no, no. But there is another way of doing this. You remember that this Committee has asked the staff to explain how the Action Matrix was developed and what does it mean -- why two reds make this and one yellow and one white.

DR. KRESS: Yes. That impacts --

CHAIRMAN APOSTOLAKIS: We can use this table now --

DR. KRESS: That impacts on that.

CHAIRMAN APOSTOLAKIS: -- to scrutinize the Action Matrix --

DR. KRESS: You're right. That would --

CHAIRMAN APOSTOLAKIS: -- rather than worrying about the thresholds for individual events, which have the problems we mentioned.

DR. KRESS: But once again, in order to do that, you have to have this missing algorithm that I talked about that says the total effect on the whole

PRA, due to the changes, which are variable, variable changes, and going in different directions, you have to have some sort of algorithm to convert that.

CHAIRMAN APOSTOLAKIS: I think Steve and his colleagues can do some sensitivity studies for us --

DR. KRESS: They might, they might.

CHAIRMAN APOSTOLAKIS: -- by taking tables like this --

DR. KRESS: They haven't done this yet.

CHAIRMAN APOSTOLAKIS: Well, because they are overwhelmed, but they can do it. They can do it. They can do these calculations, and you never know. Maybe you'll find that two whites usually lead to the same changes --

DR. KRESS: It not just a matter of doing some calculations that are sensitivity. It's a missing algorithm that's a correlation. It's a correlational algorithm between these things that's missing. It's not just a matter of doing some calculations.

DR. POWERS: But, Tom, it's not missing. It's maybe implausible to create?

DR. KRESS: Pardon?

DR. POWERS: It may be impossible to

create.

DR. KRESS: Maybe. That's my point.

CHAIRMAN APOSTOLAKIS: It could be. It could be.

DR. KRESS: And so you have to do something in its stead. And I don't know what that something is, but you have to make some reasonable assumptions or reasonable approximations that are maybe bounding or maybe a little more conservative than you might want.

CHAIRMAN APOSTOLAKIS: But I can take it the other way. What if I were doing something negative? If I take Table 4-2(a) and pick two whites or a white and a yellow from sequence 5 and sequence 20 and I calculate those delta CDF, assuming everything else is the same, and I find it's X. Then I take another white and another yellow and I find that the new delta CDF is 20 times X. Then I know I have a problem with the Action Matrix.

DR. KRESS: Well, that's something --

CHAIRMAN APOSTOLAKIS: That's a negative.

DR. KRESS: That doesn't tell you how to deal with it.

CHAIRMAN APOSTOLAKIS: No. But it tells me I --

DR. KRESS: It tells you you have a problem.

CHAIRMAN APOSTOLAKIS: Which I don't know right now.

DR. KRESS: But I already know you have a problem.

CHAIRMAN APOSTOLAKIS: I don't know that I have a problem, because these guys come in here and say it's a professional judgment; this makes sense. But this will be definite proof that you have a problem.

DR. KRESS: Well, that would be worthwhile.

CHAIRMAN APOSTOLAKIS: And then Steve will come back and justify it.

DR. KRESS: Then I would say, "I told you so."

MR. MAYS: As soon as you sign the check, George.

(Laughter.)

CHAIRMAN APOSTOLAKIS: Now, Steve, we're really running out of time, and I trust that you can summarize your presentation. Still got the letter?

MR. MAYS: Yes, we do. Let me go to move down to -- I will go with two things.

CHAIRMAN APOSTOLAKIS: This is a wonderful table, by the way.

MR. MAYS: Thank you.

DR. KRESS: Yes, that's a good table.

CHAIRMAN APOSTOLAKIS: It really is. See, again, I can't resist this. Why didn't we do all this work before revised the oversight process?

MR. MAYS: Actually, we were putting together a program, as you're aware of. From the beginning, we came down in 1995 and spoke to the ACRS about our plan for risk-based analysis reactor operating experience, and we laid out a matrix at that time that said here's the stuff we're trying to get data on, on a plant-specific basis and across systems and components and things to say this is the information we would use to be able to understand risk implications of operating experience. So we've been working on this since 1994 and 1995 time frame to get the basic methods, models, data, and information together to be able to do this kind of thing.

Now, the Reactor Oversight Program development and the crisis that came about in the summer of 1998, I guess, came here and that helped to provide an impetus for doing an oversight program that was more along the lines of what we were working on

here. And we're just continuing to try to push that envelope a little bit more as we get more data, more capability, and more information.

Because, remember, the thing we're trying to do here is go to progress, not perfection. We don't want to end up in the old source term problem where you have a source term that had a generation coming from a need and then subsequently you might have 20 years of research to get more technically capable and competent understanding of the source term, but you couldn't change it until you got one that everybody thought was more perfect. So we're trying to avoid that problem here. We recognize that there are places where this doesn't do everything you might ever want to do. But we believe it's --

CHAIRMAN APOSTOLAKIS: You're not implying that the Committee does not appreciate the distinction between progress and perfection.

MR. MAYS: No, I'm just saying that we have to make sure we keep that in mind as we go forward.

CHAIRMAN APOSTOLAKIS: The Committee does keep that in mind, just as the Committee understands what engineering approximation is.

MR. MAYS: Let's go to -- I want to go to

the alternate approach.

CHAIRMAN APOSTOLAKIS: I think you should highlight some of the good stuff you have here and tell us what you are trying to do.

MR. MAYS: Okay. I want to go to the alternate approach thing, because we've bumped into it a few times, and I want to talk about that a little bit.

One of the things we got a lot of comments on was the excessive number and increase in the PIs implicated by potentially adopting these. And the major limitation that drove us to the number of PIs that we've done was a philosophy that says that you are going to set thresholds at the basis of where you were collecting data. That's the way it had been done in the past. That's the way it was in the reactor oversight process. And we were making our first attempt at risked-based performance indicators using that.

What we subsequently decided to do was to go back and re-look at that and see if we could come up with a different concept that would reduce the overall number of indicators but still keep the fidelity towards risk that we were having in the RBPI process on a plant-specific basis.

So what we did was we said -- let's go to this Figure 1 now. If we break core damage frequency down into two major groups, the initiators and the mitigation, you can subsequently break those down into some general categories, such as transients, LOCAs, and special initiators for the initiating events. And you can break mitigation systems down, generally, into functions like reactivity control, heat removal, feed and bleed, recirculation, which are the kind of general terms people talk about when they make functional event trees or talk about risk assessments.

So let's go to Figure 3 now. What we did was we said let's reevaluate the concept a little bit. So what we would do is we'd take the same inputs that we were having for individual risked-based performance indicators in the Phase I report, and we said let's put them into a more complicated, a higher level functional model, and then compare the sequence changes in core damage frequency that we would get by exercising that model.

So we did that. This is work we've done since the Phase I draft report was published. And what we came up with was three potential hierarchies that we could do these indicators for. One of them was at the cornerstone level. So we would say -- we

would have one indicator for initiating events and mitigating systems that would represent the overall impact of all of the changes for the data that we were gathering for the individual indicators. So we would have an indicator that said for mitigating systems, whatever the changes were in reliability, whatever the changes were in availability for all the systems, we'd integrate them together through the risk model and say what was the net change in core damage frequency associated with that performance.

Now, the advantage there is we now have the integration you were talking about earlier. Maybe one system's unavailability went up, and maybe another one went down. Maybe certain performances went differently. But we would now have an integrated approach to doing that. And we would have an indicator at the cornerstone level of the reactor oversight process.

CHAIRMAN APOSTOLAKIS: And, again, an alternative to that is not to worry so much about the indicator, where to put the indicator, to keep the indicators at the lower level, but have the Action Matrix take care of these things. In other words, as you enter the Action Matrix, if you have a change in a mitigating function that I can measure its impact on

the CDF, then I react differently than if I had just something else. So there is a combination there that it's not just where I put the indicators.

MR. MAYS: The other thing we looked at, doing the same approach, was to -- we looked at putting together functional-level indicators, and we chose two groups to try this out on. One group was by initiators. So we would, for example, say four transient initiators, what is the impact of all the different variations in the mitigating systems on those sequences associated with transients. And then we'd have another indicator for those sequences associated with loss of off-site power. And we would have another indicator for those sequences associated with loss of coolant accidents. So we found that we could go back through the models and put an indicator where we would have three to five indicators per plant that were more rolled up and more integrated at a functional level, although less integrated than at the cornerstone.

And then the last level was down at the component or train level where we had already done work in the risked-based performance indicators. And at the Subcommittee, one of the things that was brought up was, "Well, why don't you just do them at

all these indicators? Why don't you have maybe an official indicator at the cornerstone level and you have functional or component level indicators so that you can understand when you have a non-green performance what specifically it was about it that was non-green and what was actually causing that condition to be done?" That's a potential possibility that we could do.

We were looking for some advice based on that concept in the stuff we showed at the -- that's in the package here as well that we showed to the Subcommittee as to whether you thought that was something we ought to pursue, that ought to be in the Phase I report or something we ought to take more time and maybe put in Phase II of the RBPI development. So we're looking for some input on that.

But we think we have models that if we take this data, we can evaluate risk performance on a plant-specific basis at whichever level we choose to. I think that's the thing you should be taking away from this. And the question of what's the right level to do is something that would have to be negotiated with the industry, the other external stakeholders, and the public to say what makes the most sense as an improvement on the existing reactor oversight process.

And there's pluses and minuses for each of them, which we discuss in some of the other slides here.

So having done that, we also had a meeting -- I want to go back to this industry one -- we also had a meeting with the public the week after we had the Subcommittee meeting, and this is a summary of some of the issues that they thought were important. I think we also presented the alternate approach at that meeting, and these are the issues that the industry folks raised during that meeting. I think these are primarily issues associated with how do we implement this stuff and what are the implications to plants in terms of the regulatory responses if we were to implement a process like this.

I think the oversight process/change process is supposed to be able to be the place where we evaluate and make assessments on that. The thing I'm looking for from the ACRS in terms of a letter, we want to know what your feelings are about whether this looks like it's a potential benefit to the reactor oversight process that should be pursued.

DR. POWERS: Steve, let me ask you this question: Suppose we did something like this and suppose I'm a member of the public and I say, "Gee, how do these guys have three fire barrier penetration

seals out of commission? It sounds pretty hazardous to me, but they tell me it's a green finding." That's what you will tell me that it's a green finding. And I say, "I wonder how in the world did they arrive at that conclusion that it was a green finding?" Am I going to be able to figure out how you got to that being a green or am I going to have to take that on faith?

MR. MAYS: I think with respect to what we've done with risked-based performance indicators, we will have the capability out there in the public domain for somebody to duplicate our analysis and our work. I mean not every single member of the public will be able to do that, but I mean we'll have the information out there so that people will be able to do that.

The case you're representing would be from the significance determination process. I'm not as familiar with the specifics of the fire SDP, but my understanding is the logic and the framework for if you have this condition, we characterize it this way and that causes a result to come out would be available and open to the public.

But I think what you're raising is a larger question. And the larger question is, how, as

an agency, do we communicate risk importance to the public and in what context do we do that? That is a significant challenge that we faced for a long time. I agree it's something that we can improve on.

I'm not sure what exactly that form should be, but I agree we're going to have problems in that area with any new oversight process that we've come up with. And people need to be able to have some sense of feeling of what does the green mean, what does the white mean, and how do I know what the implication of that is to me? Now I believe the Oversight Program tried to do that in SECY-99-007 and in the NUREG that they issued, which was the summary of that, but I'm just not in a position to really say much more than that.

DR. POWERS: It's a very thorny problem, and I choose fire protection, because fire is one of those hazards that nuclear power plants face that's very palpable to any individual. I mean you just know fire is a bad idea, and you kind of know what it's going to do. And so when you see failures in the fire protection system, some of those are very familiar. They're unlike pressurizers or high-pressure injection systems. You have many of them in your own house or your own business that you work at.

And so you see failures of these things. You say, "Gee, that ought to be significant. I would do something about that in my own business if I saw those fire penetration seals failing." And it's not the licensee is not doing something about it. It's that the regulator doesn't feel like he needs to do anything about, because he finds it a green finding. But that' not very easily communicated to an individual who has been cautioned to worry about nuclear power plants.

I mean it came up today in the meeting with the Commission. I think it's an area that we can't continue to say, "Gee, that's a problem we're going to have to address one of these days." We've got to address it. And it seems like you have the vehicle for doing it.

CHAIRMAN APOSTOLAKIS: I just don't think that's a problem.

MR. MAYS: Well, I think we have a --

CHAIRMAN APOSTOLAKIS: Why don't you tell the public whatever that means that green means that, look, this is a major industrial facility. It has 40,000 components, it has 800 people working on it. Little things happen here and there. By design and regulations and so on we have allowed for these, and

in this particular case our analysis shows that it has an insignificant impact. What's wrong with that?

MR. MAYS: Well, I think you're touching on one of how might one go about doing that, and I think my interpretation of Dana's question is do we have an agency process for making sure that that kind of communication takes place in a consistent way so that people have an understanding of that? That's the age-old question that Chauncey Starr raised years ago in his "Perceptions of Risk" Paper.

And I think Dana's correct, every person in their house can say, "Oh, I know fire's a bad thing." I had a fire in my kitchen once. But nobody understands what the issue about the availability of the high-pressure core spray pump, because they don't have any high-pressure core spray pumps. Maybe they can make an analogy to their sump pump in their house or something, I don't know.

But I think risk communication is an important feature that we have to be able to do as an agency in order to meet our strategic goals for public confidence. I just don't think --

CHAIRMAN APOSTOLAKIS: The reactor oversight process, I thought it was very good. Have you guys seen this?

MR. MAYS: Yes.

CHAIRMAN APOSTOLAKIS: No, I know you have. Have you gentlemen seen it?

MR. MAYS: Thanks a lot, George.

(Laughter.)

MR. BOYCE: If I could use that as a segue a minute. We have to face this issue in the reactor oversight process today, how do you communicate SDP results in a coherent manner that's understandable? And what you have to look at -- it primarily comes down to the web page really.

DR. POWERS: Even to very technically sophisticated people, how do you communicate the SDP results?

MR. BOYCE: That's exactly right. And we have that problem. And the primary vehicle, actually, turns out to be the web page for everybody. And everybody includes intervenor groups, casual members of the public who are browsing from America Online, licensees, staff members --

CHAIRMAN APOSTOLAKIS: Do you have any data that showed you -- give you some idea of how many members of the public actually do this?

MR. BOYCE: Actually, yes. If you go onto -- in fact, you can access it from the internal web

yourself. If you go onto NRC's home page, there's a spot there that says, "Web Statistics." And it will tell you -- it's actually pretty good. It's a contractor program --

CHAIRMAN APOSTOLAKIS: What does it tell you?

MR. BOYCE: -- that collects data on I guess it's the domain names that have accessed the pages, the entrance page, the exit page, the number of hits on a page, and that sort of thing.

CHAIRMAN APOSTOLAKIS: But that doesn't tell you that these people were public.

MR. BOYCE: Well, what you end up doing is you find out that they come from aol.com, and you find out they come from nrc.gov, and you find out that they come from dot-org. And, so you can get a rough idea of the usage.

CHAIRMAN APOSTOLAKIS: Oh, you know that. Okay. So there are some data.

MR. BOYCE: Yes, from the domain names.

CHAIRMAN APOSTOLAKIS: So there is a significant number of hits from --

MR. BOYCE: From the members of the general public.

CHAIRMAN APOSTOLAKIS: -- a basis where we

might suspect there is public involved?

MR. BOYCE: Well, yes. As a matter of fact, one of the -- it's interesting that whenever we issue a press release, the number of hits spikes on our web pages.

CHAIRMAN APOSTOLAKIS: Whenever you do what?

MR. BOYCE: Whenever we issue a press release.

CHAIRMAN APOSTOLAKIS: Is that right?

MR. BOYCE: The number of hits spikes. And it comes from places like America Online. The geographical --

CHAIRMAN APOSTOLAKIS: But it could be inside NRC?

MR. BOYCE: It may very well could be.

CHAIRMAN APOSTOLAKIS: I mean those guys are professionals. I don't count them as public.

DR. WALLIS: Well, the press releases is attractive, because it might be understandable. I think a hit doesn't mean that the person who hit understood what he read.

MR. BOYCE: Correct.

DR. WALLIS: That's the problem I think you have.

MR. BOYCE: Correct. And trying to bring it back to where we are, the web pages is our primary vehicle for communication right now. And what we have tried to put on it is this colorized scheme to make it easier to understand. And we put all our inspection reports by cornerstone on the web page so that you start off with a color, and if you have a white color or yellow color, you can click on the color and you get down to the next level of detail. The next level of detail would be perhaps an NRC assessment letter saying, "We've reviewed your performance over the previous year, and this is our assessment." If you want to know about a specific topic, like an inspection finding, you click on that color. It will take you down to the inspection report, which talks about the NRC's view of that.

We're getting to the point where we're putting our, what we call, SDP letters on the web so that all the information and how we characterize it will be there. I'm not going to tell you it's perfect, but it's what we're doing today. We've gotten additional -- we had a public communication session as part of our lessons learned workshop at the end of March, and we got a lot of feedback that we needed to do better in this regard.

So we're at the forefront telling you what we're doing. We can't solve the world's problems, but here we are.

CHAIRMAN APOSTOLAKIS: Steve, is there anything else that you think you should point out to the Committee?

MR. MAYS: No, I think the key thing that I want you to come away with is that we have the ability, using readily available data and models, to be able to estimate plant-specific performance impacts on risk in several areas that are broader, more comprehensive, and can be integrated, using the alternate approaches we're proposing here, to give us indication of performance at various levels. And if this is something the Committee thinks we should go forward with, we would appreciate hearing about it. If there are aspects of how we're doing it you'd like us to do different, we'd like to hear about that too.

I think realistically it's going to take a considerable amount of time to meet with the external folks, go through process, because this is going to be primarily voluntary process to do. And we're going to have to show people what we have, examine the stuff in a bigger picture than just what the technical stuff is. But I want the implications

of what it will mean to you. But that's specifically what the Reactor Oversight Process Change Program and procedure is designed to do.

CHAIRMAN APOSTOLAKIS: You said that your so-called alternative approaches are described where?

MR. MAYS: They're only the presentation we made to you on the Subcommittee and the stuff that's in this particular thing. They are in the report, because we got these comments after the draft report was put out, and we went to be proactive rather than just sitting on our hands until the comments came in that says, "That's too many PIs." We said, "Well, what other things, since we know that issue, can we go work on now?" And what we've done is we said, "There are some things that we could do that can solve some of the problems we've had in other areas."

Because one of the things we found, for example, in the ROP comparisons in this, when did the integrated look, we found that sometimes we would have, on an individual PI basis, a green and a white. And when you get to the integrated, it comes out green, because the green had improved so much and it was on the same sequence as the white, it basically counteracted it. And on the other hand, we found cases where we had green and green indicators, and you

put them in the integrated indicator and they come out white, because they were green, but they were both getting worse at the same time. So even though one individual didn't cross over an individual threshold together, they would have crossed the threshold. I think that's an important -- from my risk perspective, that's an important piece of information to have.

CHAIRMAN APOSTOLAKIS: It's very important.

MR. MAYS: And we also had -- in the ROP comparison stuff, we had examples where the ROP would indicate one color, and we would see worse and other cases where the ROP would say worse, and we would see green. And we were able to go back and look at each one of those specific cases and look at them from the standpoint of what's making this true and that face validity test, which we used in the slides, we were able to come to a reasonable conclusion from a risk perspective of why that really was true.

For example, we were using a plant-specific threshold instead of a generic threshold. For example, we weren't averaging diverse trains; we were using individual trains. So those were all the kinds of things we found that I think tell me, anyway, we can do a better job of understanding risk

performance with this process than the current ROP. And, again, progress not perfection. That's not saying it's broken and dead and is wrong. We're saying what we have here is potentially better.

CHAIRMAN APOSTOLAKIS: What you're saying -- I'll give you an example for me to understand it better. A particular indicator of the plant may formerly be yellow but because the utility is aware of it and they're doing something else better, the overall impact may be zero, right?

MR. MAYS: Well, the impact may be white, it may be green, it may be still yellow, I don't know. What I'm saying is without an integrated model you can't tell.

CHAIRMAN APOSTOLAKIS: And you have the tools to investigate.

MR. MAYS: I think we have the tools to investigate that.

CHAIRMAN APOSTOLAKIS: Speaking of tools, Steve, do you also have tools to test the hypothesis that if human performance and the safety culture of the plant deteriorates, then we will see the impact on the equipment decline in performance?

MR. MAYS: We have the tools to determine when we see degradations in the performance of the

equipment, whether or not the factors causing that were related to Corrective Action Program or other things. We don't have tools to directly measure Corrective Action Program and then posit what the risk impact would be. So if you were to look at public risk and make yourself a hierarchy, here's public risk, and then somewhere below public risk is core damage risk, and somewhere below that is system or train level performance, and somewhere below that is component performance. I think what you see is that the safety culture is somewhere below that in terms of being how leading you want to get from public risk down to the least level of detail that you might be able to do.

I don't have metrics to link safety culture measures that --

CHAIRMAN APOSTOLAKIS: But do you have tools?

MR. MAYS: I have tools to be able to see when I see a performance degradation at the lower levels of risk to be able to go back and examine whether the fundamental causes of that were safety culture, corrective action or other problems.

CHAIRMAN APOSTOLAKIS: So maybe that's something different. Maybe it has to do with root

cause analysis.

MR. MAYS: Correct.

MR. HAMZEHEE: If the impact is on the equipment performance.

MR. MAYS: Right, if the impact is on --

CHAIRMAN APOSTOLAKIS: Don't give me cryptic statements, Hossein.

MR. MAYS: If the impact were to be --

CHAIRMAN APOSTOLAKIS: What else could it be?

MR. MAYS: Well, for example, on the ability of the operators to respond to an accident. So we don't have data on being able to make sure that you initiate slick within five or ten minutes after an accident. So we don't have that kind of data either.

CHAIRMAN APOSTOLAKIS: Okay.

MR. BOYCE: The Allegation Program does compile statistics at an industry level.

CHAIRMAN APOSTOLAKIS: But we are not using those to confirm this hypothesis.

MR. BOYCE: Correct. In terms of tools, it's not a tool, but that's at least the best indicators we have for a safety conscious work environment.

DR. WALLIS: George, you never confirm my

hypothesis; you just disprove it.

CHAIRMAN APOSTOLAKIS: Yes, yes. I stand corrected. Thank you, gentlemen. This was a very lively session; appreciate it. Are you happier today?

MR. BOYCE: I was able to respond better to your questions today, which does make me happier.

CHAIRMAN APOSTOLAKIS: Okay. Thank you very much. Now we will hear from Mr. Houghton of NEI.

MR. HOUGHTON: Good afternoon. My name is Tom Houghton. I am the Project Manager for the reactor oversight process at NEI.

DR. KRESS: This is your first test to see if you can turn that on.

MR. HOUGHTON: First test is -- okay. Well, I think I have four slides here, and I've tried to summarize a lot of points on these. We do support movement towards risked-based performance indicators with some caveats. And the caveats, a very important one, depends upon the ability to integrate what's going on across the different aspects of regulatory space. And by that I'm particularly talking in the mitigating area to the dichotomy between design basis technical specifications and risked-based performance indicators.

And it plays a big role, because the

inspectors inspect to the design basis, and if we're trying to move towards risked-based performance indicators, we're shifting the focus of this performance indicator. The performance indicator's purpose is not to measure risk. performance indicator's purpose is to help the NRC manage its resources and determine where to put its inspection resources. So the inspectors are aiming at design basis, i.e. the automatic function would not have worked. And the risk-based indicator allows operator recovery, because the mission time is seven days, and there is seven days to restore the function.

We have a big dichotomy here. And we're seeing that already between the Maintenance Rule and the tech specs. And we'll see it even more in the risked-based performance indicators unless we address this problem up front with a plan that solves the problem so we're not having people going in different directions. And that really is a key issue in going forward with risked-based performance indicators.

Second point I put on here is the PIs and the inspection findings, their aim is to tell the inspectors how much additional inspection to do beyond the baseline. And, therefore, the indicators need to provide that value at the same time not adding

additional burden and to help us all focus on what's risk-important. Now, I said complement inspection activity, I didn't say reduce.

DR. WALLIS: This refrain about avoiding unnecessary burden, there's always a complementary side. When additional burden is appropriate it should be there.

MR. HOUGHTON: Absolutely, absolutely. Now, I agree with you, but to do that, one needs to look and say, "Okay, the current number of hours in the baseline inspection is actually slightly higher than it was."

DR. WALLIS: You really should say the regulatory burden should be appropriate.

MR. HOUGHTON: Yes, yes. It should be appropriate. To do that, one needs to ensure that additional reporting falls under 50.9 and has to be accurate to very fine levels is appropriate for the amount of effort people are going to have to put into that. And we do have inspectors that have gone down and looked at 15 minutes of availability time, of the time that was written in the log, as opposed to something else. And it can cause a lot of inspection effort by the NRC and by the licensees unless we're careful. And by adding additional indicators, we add

to that area. So that we would say, let's add more indicators, but let's have a tradeoff here. And if there is no tradeoff, then there's no advantage to doing it other than to gather more information to what purpose.

This 0609 Manual Chapter is the chapter that tells NRC how to proceed with interpretations of performance indicators, and we've had about 256 questions over the year on interpretation of indicators, mostly in the mitigation unavailability area. But it tells them what process to go through. And I think although research is -- as I understand it, research's duty here is to look at the technical feasibility, but we're looking ahead to see if these indicators are practicable to be used, okay?

So we're looking at those aspects, okay, easy to understand. We would wonder an indicator which rolled up, either to a cornerstone or at a higher level and how difficult that would be for someone to be able to readily understand. I mean you may not know what a high-pressure injection system is, but you know it's a system. If you're talking about the cornerstone of initiating events, that's an abstraction.

I think I covered the other points there,

but the 608 is important.

DR. POWERS: Could you explain the title of the slide? The title has me confused.

MR. HOUGHTON: Oh. I'm glad you asked that, because I should have discussed that. The purpose of the performance indicators and the inspection findings is to help determine where management should put resources. And we basically have three stakeholders. We've got the Regulatory Commission, which needs to assign resources, we've got the industry, and we've got the public. And our feeling is is that you have to -- these indicators have to meet the needs of all three stakeholders in this process. So you can't have extremely sophisticated indicators, you can't have indicators that are hard to collect accurately, and you've got to have indicators that are actionable by the Commission and by the people that are living with them. That's my point.

DR. POWERS: I understand better now. First I thought we were talking about producing electricity.

MR. HOUGHTON: I'll hold it at the ROP level.

Some comments on the draft PIs themselves,

and I think this is partly understanding and working through. But the thresholds need to be set at practical levels for action. That may vary from what a very strict risk study tells you. So if I were to look, for example, at the loss of heat removal threshold for one of the plants in the study, you'd be allowed 0.7 reactor scrams with the loss of heat removal in a three-year period. That means your threshold is less than one. That means there is no threshold. There are some difficulties in going strictly by a risk-based threshold system. It needs to be modified to be practicable.

Another example for you is the general transient green/white threshold, as I looked through the plants that were reviewed, varied. One plant would have a threshold of 1.2 general transient scrams per year; another one would have 8.2. Now if I'm a plant manager and I have two scrams in a year and I get an extra inspection and I get a mark of a white, and my neighbor has eight scrams in a year, and he is considered in the green band, that doesn't make sense. It just doesn't make sense. It has to be an indicator which is --

CHAIRMAN APOSTOLAKIS: No, but -- well, in all fairness, if you're running a plant where the

threshold is two, there must be some serious reasons why.

MR. HOUGHTON: No, I think it -- and I defer to the risk experts, but the threshold is based on a ten to the minus six delta CDF.

CHAIRMAN APOSTOLAKIS: Yes, but that is converted for your plant to a threshold of two, which means you don't have enough mitigating capability, right?

MR. HOUGHTON: But this PI won't get at that problem.

CHAIRMAN APOSTOLAKIS: So you should pay the price. That's the way I see it.

MR. HOUGHTON: But the PI won't get at that problem.

CHAIRMAN APOSTOLAKIS: No, the threshold gets at the problem.

DR. POWERS: For your first example, you just want that to be one per four years, is that all?

MR. HOUGHTON: Well, right now we've combined the loss of heat sink and the loss of -- the current indicator combines the loss of heat sink and loss of feedwater, and the green/white threshold is actually two. And there are several plants that have tripped that threshold, and they've done extensive

cause analysis for the situation. But that isn't a -- I'm pointing out that there are practicalities that need to be -- you can't blindly use a risk-based approach.

CHAIRMAN APOSTOLAKIS: And what I'm saying is that, you know, of course you should be practical, but at the same time, there is a reason behind this. And maybe a plant that is very well defended can afford to have maybe a couple more transients a year. Whereas another one that is not may be should not.

DR. POWERS: Wait until you see the kind of performance indicators we were talking about earlier that are very much more complex. I mean then you'll have some real problems with that practicality.

MR. HOUGHTON: But I would think --

CHAIRMAN APOSTOLAKIS: No, I appreciate the point, but I want you to appreciate mine.

MR. HOUGHTON: Yes, sir; I do. But I would say is that the venue for the discussion of whether you have a robust enough mitigating system is not the ROP, because the ROP is looking at your performance under the current rules and regulations and activities you're supposed to do.

CHAIRMAN APOSTOLAKIS: Anyway, you're talking about the draft PIs as given by these guys

today?

MR. HOUGHTON: Yes, yes.

CHAIRMAN APOSTOLAKIS: Okay.

MR. HOUGHTON: And we went through these discussions, actually, when we set the thresholds in the ROP, because we did have differences such as these, and what happened was is there was an accommodation of, "Well, let's use three scrams per year. Even though one plant is 2.1 and another is 7, we'll use three, because what we're really trying to do is look at are you maintaining and operating in an effective manner."

The mitigating systems, the most important issue, as I said to you several weeks ago, is the unavailability definition. And as I just said, it gets into issues of design basis versus risk basis. It gets into credit for operator action. It gets into cascading of support systems and whether we do that or not. And it gets into the reliability indicator in place of demand fault exposure. And we're very -- we support very much working towards, moving towards a more risk-based approach in this area, because we think that's appropriate, and it's more in line with the Maintenance Rule, and it can help to avoid this problem. I talked about it, having two or three

different targets that you're aiming at.

MR. MAYS: Tom?

MR. HOUGHTON: Yes.

MR. MAYS: If I might, the issues on design and licensing basis for unavailability and whether or not operator action is credited and role support systems and the fault exposure times were all issues that in the draft RBPI were done in the direction to which you're concerned that we should be moving.

MR. HOUGHTON: Yes, I agree, and that's what I was trying to say. We see that as moving positively. However, the tech spec issue is looming out there.

The component class PIs, we feel that better covered by the SDP and by the extent of condition in root cause analysis rather than having separate PIs. We don't feel there's a -- that there would be less inspection coming about through having PIs in those areas.

Now on the shutdown PI, I think there was some discussion of the level of our concern in terms of the amount of time and basing it on time when we think that you could have negative consequences of people trying to rush out of conditions. And it's not

really appropriate to have indicators like this. We want to hear more about it, but when you look at some of the thresholds in that table, you'll find that they're very unforgiving, and you can move from being green to yellow in just two or three hours. And when you're trying to be careful you don't want to put yourself in that situation. It's not clear that that's a good idea. We do think that it could be very helpful in the Phase II once you know you have a problem to see what sort of the risk level was.

Adding PIs requires examination of the Action Matrix. A comment here: I heard the talk about rolling up PIs to a higher level and then putting that in the Action Matrix. But the Action Matrix includes both the inspection findings and the PIs. And the Action Matrix really is more of a logic table to tell you if you have two or more -- if you have single white, be it a PI or an inspection finding, the NRC is going to look at your root cause and look at your corrective action. And it might require up to 40 hours of additional inspection. That's what that means.

The second column tells you that you have two or three white indicators in a particular cornerstone, whether that's physical security or

emergency planning or the barriers or mitigation. And what it's saying is, "We're not so sure you're handling things right, and we're going to come and look at your ability to do root cause and look at your ability to integrate this problem across different systems."

The next column, a yellow or degraded cornerstone says, "You have a more systemic problem and we're going to increase the inspection level higher." The next column probably has you in a diagnostic, like Indian Point. There's a very interesting inspection report that showed Indian Point if it had been under the new system for the year prior to the steam generator tube rupture. And it shows you that the Action Matrix in the system would have shown a steady degradation and the need for more inspection earlier on at Indian Point. I commend that to you to see how that worked, because that's an actual case study. It wasn't applying to them at the time.

So we see the Action Matrix as not being a risk meter at a certain level, but we see it as indications of problems across distinct areas. And as they increase, the Agency needs to take a closer and closer look at the problem. So we would really feel that aggregating these PIs you still have to compare

it with inspection findings, so you're not really integrating risk with the inspection findings. And we really think that the PIs at the level they are are actionable indicators.

DR. WALLIS: I understand that, but remember the public looking in, this is really a risk meter, and the public is not interested in a management tool. It's interested in how a state complies.

MR. HOUGHTON: Well, but they're interested, I think, in how does the NRC judge the plant. And you now can click on the Action Matrix, and you can see the 79 plants that are in the licensee control band, the 16 or 18 that are in the next one, the three or four that are in the next one, and finally Indian Point on the site. And it also tells you why they've changed from column to column. So it --

DR. WALLIS: I don't really care about that. If I was a member of the public, I probably look at it say, "Well, I want a good feeling that these things are safe enough. Here's a measure I've got." So it's going to be used in some way as a risk meter whether you like it or not.

MR. HOUGHTON: Agreed, but I'm not sure

that -- it's not clear to me that a risk number would tell someone more than being told that there are systemic problems across different areas. That's my opinion.

MR. SIEBER: It seems to me that that's a two-edge sword. For example, if you could predict the declining performance at Indian Point and then begin doing diagnostics and additional inspections, that probably would not have prevented the tube rupture.

MR. HOUGHTON: Right.

MR. SIEBER: Okay. So now the Agency is called into question. You knew this Plant was going downhill, yet you weren't able to prevent this event, even though the two are not associated. And I think you have to be careful about that, because a lot of these events are random events.

MR. HOUGHTON: Well, and that's very true is that things are going to happen that are not going to be caught by inspection, and they're not going to be caught by performance indicators.

MR. SIEBER: Yes, there's another effect that occurs that I've seen happen in plants is you go in with a diagnostic team that lasts three, four, five weeks and has five to ten people on it. That really disrupts the operation of that plant. And I think

that plant is more vulnerable during that time when an inspection is going on from a risk standpoint.

MR. HOUGHTON: They certainly find more things.

MR. SIEBER: They certainly do, and it ties up management, and it ties up your engineering staff, it ties up your licensing people, and it has to be done, but it's a cross-cutting issue.

MR. HOUGHTON: Although they might not have -- and I think the system, the way it works now, does attack cross-cutting issues, because it says, "Do I have a problem across different areas?"

MR. SIEBER: Right.

MR. HOUGHTON: Which says, "Does my maintenance force have a problem with the Corrective Action Program? Does my training organization have a problem with operations experience from other plants?" So that it does give you a feeling of whether there are problems across different aspects of the organization, which rolling up, to me, doesn't quite give --

MR. SIEBER: Thank you.

MR. HOUGHTON: Other questions for me? Appreciate the opportunity to talk to you.

CHAIRMAN APOSTOLAKIS: Thank you very

much; appreciate it.

Now, we will not need transcription after this point. And tomorrow afternoon, actually, we'll see you again at 1:30 when we discuss the general design criteria. Because in the morning there is no need for transcription.

(Whereupon, at 3:32 p.m., the NRC Advisory Committee Meeting was concluded.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: ACRS 482[nd] Meeting

Docket Number: (Not Applicable)

Location: Rockville, Maryland

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Rebecca Davis

Rebecca Davis
Official Reporter
Neal R. Gross & Co., Inc.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

May 2, 2001

REVISED
SCHEDULE AND OUTLINE FOR DISCUSSION
482nd ACRS MEETING
MAY 10-11, 2001

THURSDAY, MAY 10, 2001, CONFERENCE ROOM 2B3, TWO WHITE FLINT NORTH, ROCKVILLE, MARYLAND

1) 8:30 - 8:35 A.M. Opening Remarks by the ACRS Chairman (Open)
- 1.1) Opening statement (GEA/JTL/HJL)
- 1.2) Items of current interest (GEA/HJL)
- 1.3) Priorities for preparation of ACRS reports (GEA/JTL/SD)

2) 8:35 - 10:20 A.M. Final Review of the License Renewal Application for Arkansas Nuclear One (ANO), Unit 1 (Open) (MVB/GML/SD/RBE)
- 2.1) Remarks by the Subcommittee Chairman
- 2.2) Briefing by and discussions with representatives of the NRC staff and Entergy Operations, Inc. regarding the license renewal application and for ANO, Unit 1 and the associated staff's Safety Evaluation Report.

10:20 - 10:30 A.M. ***BREAK***

3) 10:30 - 12:30 P.M. Members Attendance at the Commission Meeting on the Office of Nuclear Regulatory Research Programs and Performance (Open)
Drs. Powers and Wallis are scheduled to participate in this meeting which will be held in the Commissioners' Conference Room at One White Flint North. Other members will be attending this meeting as observers.

12:30 - 1:30 P.M. ***LUNCH***

4) 1:30 - 3:00 P.M. Risk-Based Performance Indicators (Open) (GEA/MTM)
- 4.1) Remarks by the Subcommittee Chairman
- 4.2) Briefing by and discussions with representatives of the NRC staff regarding the staff's draft document entitled, "Risk-Based Performance Indicators: Results of Phase 1 Development," and related matters.

3:00 - 3:15 P.M. ***BREAK***

5) 3:15 - 4:15 P.M. Discussion of South Texas Project Nuclear Operating Company (STPNOC) Exemption Request (Open) (JDS/GEA/MWW)
The Committee will discuss the South Texas Project Nuclear Operating Company Exemption Request.

6) 4:15 - 7:00 P.M. Proposed ACRS Reports (Open)
Discussion of proposed ACRS reports on:
6.1) License Renewal Application for ANO, Unit 1 (MVB/GML/SD/RBE)
6.2) Management Directive 6.4 Associated with the Revised Generic Safety Issue Process (TSK/AS)
6.3) Risk-Based Performance Indicators (GEA/MTM)

FRIDAY, MAY 11, 2001, CONFERENCE ROOM 2B3, TWO WHITE FLINT NORTH, ROCKVILLE, MARYLAND

7) 8:30 - 8:35 A.M. Opening Remarks by the ACRS Chairman (Open) (GEA/JTL/HJL)

8) 8:35 - 10:00 A.M. Discussion of Topics for Meeting with the NRC Commissioners (Open) (GEA, et al./JTL, et al.)
The Committee will discuss topics scheduled for its meeting with the NRC Commissioners.

10:00 - 10:30 A.M. ***BREAK***

9) 10:30 - 12:30 P.M. Meeting with the NRC Commissioners (Open) (GEA, et al./JTL, et al.)
Meeting with the NRC Commissioners, Commissioners' Conference Room, One White Flint North, to discuss the following:
9.1) Proposed Framework for Risk-Informed changes to 10 CFR Part 50 (WJS/MTM)
9.2) South Texas Project Exemption Request (JDS/MWW)
9.3) Issues Associated with Thermal-Hydraulic Codes (GBW/PAB)
9.4) Status Report on Steam Generator Tube Integrity Issues (DAP/SD/MTM)
9.5) Status of ACRS Activities Associated with License Renewal (MVB/RBE)

12:30 - 1:30 P.M. ***LUNCH***

10) 1:30 - 2:30 P.M. Discussion of General Design Criteria (Open) (GEA/JNS)
10.1) Remarks by the Subcommittee Chairman
10.2) Briefing by and discussions with Mr. Sorensen, ACRS Senior Fellow, regarding his views on risk-informing the General Design Criteria that are included in Appendix A to 10 CFR Part 50.

11) 2:30 - 3:15 P.M. Future ACRS Activities/Report of the Planning and Procedures Subcommittee (Open) (GEA/JEL)

11.1) Discussion of the recommendations of the Planning and Procedures Subcommittee regarding items proposed for consideration by the full Committee during future ACRS meetings.

11.2) Report of the Planning and Procedures Subcommittee on matters related to the conduct of ACRS business, and organizational and personnel matters relating to the ACRS.

3:15 - 3:30 P.M. ***BREAK***

12) 3:30 - 3:45 P.M. Reconciliation of ACRS Comments and Recommendations (Open) (GEA, et al./SD, et al.)
Discussion of the responses from the NRC Executive Director for Operations to comments and recommendations included in recent ACRS reports and letters.

13) 3:45 - 4:00 P.M. Miscellaneous (Open) (GEA/JEL)
Discussion of matters related to the conduct of Committee activities and matters and specific issues that were not completed during previous meetings, as time and availability of information permit.

NOTE:

- **Presentation time should not exceed 50 percent of the total time allocated for a specific item. The remaining 50 percent of the time is reserved for discussion.**

- **Number of copies of the presentation materials to be provided to the ACRS - 35.**

Comments on Draft Risk Based Performance Indicators

Tom Houghton

Senior Project Manager, NEI

NEI

Industry Supports Movement Toward RBPIs which add value

- Need for an integrated strategic approach:
  - Design/Licensing Basis versus Risk-Based approach
  - Tech Specs and Maintenance Rule targets already vary -- must avoid adding a third target
- Any change or addition to PIs must enhance the inspection, assessment and enforcement process:
  - Improve understanding of risk-significant issues
  - Avoid unnecessary/additional regulatory burden and
  - Complement inspection activity

NEI

RBPI Effort Needs to Focus on End Product/Customer Needs

- Key success criteria in change management process (IMC 0608) should be considered now:
  - Easy to understand by industry and the public
  - Easy to report accurately and with minimal clarification
  - Low potential for inappropriate motivation to change operations or maintenance practices
  - More focus on risk significant issues
  - More efficient inspection

NEI

Comments on Draft PIs

- Initiating Event Thresholds must be practical
  - Example: Plant 22 LOHS G/W threshold 0.72 / 3yr
  - Example: GT G/W threshold that varied from 1.2 to 8.2 /yr
- Mitigating Systems
  - Most important issue is unavailability definition
    - Design/Licensing Basis vs. Risk Basis
    - Credit for operator action
    - Cascading of support systems
    - Reliability indicator in place of demand fault exposure
  - Consistency between Maint Rule, Tech Specs, and PIs
  - Component Class PIs are covered now by SDP and Corrective Action Programs

NEI

Comments on Draft PIs

- Shutdown PI
  - May conflict with Technical Specifications, AOTs, Maintenance Rule and NUMARC 96-01 guidance
  - May drive inappropriate actions
  - Concept could possibly be helpful in phase 2 SDP; however, threshold time periods seem inappropriate
- Adding PIs requires reexamination of Action Matrix
- Aggregating PIs to higher levels counters basic principles of ROP PIs
  - Purpose of PIs is to provide indication of where additional attention and action is necessary -- it is a management tool, not a risk meter
  - Aggregation disguises specific actionable areas

NEI

RISK-BASED PERFORMANCE INDICATORS

RESULTS OF PHASE-1 DEVELOPMENT

PRESENTATION TO ACRS

Steven E. Mays (415-7496)
Hossein G. Hamzehee (415-6228)
Office of Nuclear Regulatory Research
Michael R. Johnson (415-1241)
Office of Nuclear Reactor Regulation

May 10, 2001

Phase-1 RBPI Development Results

- The objectives of this presentation are to:

  - Provide perspective on relationship of RBPIs to ROP
  - Present summary of results from draft Phase-1 RBPI development report
  - Discuss Alternative approaches for developing RBPIs
  - Discuss industry inputs from 4/24/01 public meeting
  - Address questions raised during April 17 presentation to ACRS Subcommittee on PRA

- We are asking ACRS to provide feedback (via a letter) on:

  - Potential benefits of RBPIs to the Reactor Oversight Process (ROP)
  - Technical feasibility/adequacy of RBPIs
  - Alternative approaches for developing RBPIs in response to stakeholders concern over total number of RBPIs

Phase-1 RBPI Development Results

Relationship of RBPIs to ROP:

- Goals of Commission PRA Policy Statement and NRC Strategic Plan (NUREG) are to better risk-inform NRC processes.
- ROP was revised to be more risk-informed, objective, understandable, and more predictable than previous oversight process.
- Continuing advances in industry use of information technology and data
  - Gathering/analyzing more plant-specific and industry-wide data
  - Internet and micro-computers allow improved capabilities to gather/share data
  - NRC and industry continue to expand their capabilities to model/assess risk-significant attributes of plant operations

Phase-1 RBPI Development Results

Relationship of RBPIs to ROP (cont'd):

- As discussed in SECY-99-007 and 99-007A, ROP uses both inspection findings and performance indicators

- As discussed in SECY-00-049, while future success of the ROP is not predicated on the RBPI program, RBPIs would potentially support:

  - Enhancements to specific areas in current ROP where RBPIs may be applicable
  - Future development of more plant specific PIs using improved risk analysis tools

- In response to NRR User Need Letter, RES examined feasibility of selected RBPIs as part of Phase-1 report.

  - Reliability indicators
  - Unavailability indicators
  - Shutdown and fire indicators
  - Containment indicators

Phase-1 RBPI Development Results

Relationship of RBPIs to ROP (cont'd):

- Several key implementation issues are identified in Section 5 of Phase-1 report, some of which are:
  - Data quality and availability
  - SPAR model development and V &V

- Process for potential integration of RBPIs with ROP
  - Assess feedback from stakeholders on Phase-1 report to ascertain an appropriate course of action
  - Consideration of safety benefits/costs
  - Follow process for changing ROP performance indicators in IMC0608, which includes opportunity for stakeholder involvement
  - A pilot program would be conducted prior to considering any RBPIs for full implementation
  - Additional PIs may require re-assessment of ROP Action Matrix

Phase-1 RBPI Development Results

Potential Benefits of Proposed RBPIs:

- Broader sample of plant performance impacting risk than current ROP indicators. Provides more objective indication of plant performance to licensees, NRC, and the public.

- Better understanding of plant-specific risk implications than current ROP indicators

  - Plant-specific thresholds
  - No averaging of diverse system trains which can mask actual risk contribution
  - Failures affecting reliability/availability are based on loss of risk-significant functions, not design-basis functions

- RBPI process will look similar to performance indicators in the current ROP

- RBPIs can be implemented in part rather than as an entire set.

- RBPIs are a straightforward extension of existing models, data, and capabilities. No significant new infrastructure is needed to support them.

Phase-1 RBPI Development Results

RBPI Development Process:

- RBPIs were developed using four major steps (Figure 2.1):

  1. Assess potential risk impact of degraded performance
  2. Obtain performance data for risk-significant elements
  3. Identify indicators capable of detecting performance changes in a timely manner
  4. Identify performance thresholds consistent with a graded approach to performance evaluation from SECY 99-007

- Successful development of potential RBPIs requires:

  - Models that reasonably reflect risk impact
  - Baseline performance for setting thresholds
  - Ongoing performance data for assessing plant-specific performance against performance thresholds

Summary of RBPI development Results

Table ES-1 Summary of Phase-1 Risk-Based Performance Indicators

Safety Cornerstone	Existing PIs	Proposed RBPIs			
Initiating Event	- Unplanned Scram - LONHR - Unplanned Reactor Power Changes	- General Transient - LOFW - LOHS			
		PWR at Power	**BWR at Power**	**Shutdown**	**Fire**
Mitigating System	- EPS (UA) - RHR (UA) - PWR AFW (UA) HPI (UA) - BWR HPCS/HPCI (UA) RCIC/IC (UA) - Safety system functional failures	- EPS (UR&UA) - AFW-MDP (UR&UA) - AFW-TDP (UR&UA) - HPI (UR&UA) - PORV (UR) - RHR (UR&UA) - SWS (UR&UA) - CCW (UR&UA) - AOV (UR) - MOV (UR) - MDP (UR)	- EPS (UR&UA) - HPCS/HPCI (UR&UA) - RCIC/IC (UR&UA) - RHR (UR&UA) - SWS (UR&UA) - AOV (UR) - MOV (UR) - MDP (UR)	- *Time in High/Medium/Low Risk-Significant Configurations	- *Fire Suppression System (UR&UA)
Barriers	- RCS Specific Activity - RCS Identified Leak Rate	- *CIV (UR&UA)	- *Drywell Spray (MarkI)(UR&UA) - *CIV (Mark III) (UR&UA)	None	None

* Requires data that are not currently reported.

Note: The emergency preparedness, occupational radiation safety, public radiation safety, and physical protection cornerstones of safety are not included in the Phase-1 RBPI scope.

Summary of RBPI development Results

Shutdown Modes:

- Measures impact of configuration rather than accumulation of performance over time.
- Proposed mitigating system RBPIs during shutdown reflect excess time spent in risk-significant shutdown configurations
- Monitors time in excess of baseline based on nominal refueling outages
- Four shutdown configuration categories are defined based on CCDF: Low, Medium, Early Reduced-Inventory (vented), and High (Table 3.2.2-1 and 3.2.2-2)
- Risk-significant shutdown configurations are categorized by:
  - RCS conditions
  - time after shutdown
  - availability of mitigating system trains

Table 3.2.2-1 Baseline and Thresholds for Time in Risk-Significant Configurations Indicators - PWRs

Configur. Category	Baseline	G/W Threshold	W/Y Threshold	Y/R Threshold
Low	20 days	21 days	30 days	120 days
Medium	2 days	2 days + .08 day (2 hrs)	3 days	12 days
Early Reduced-Inventory (vented)[a]	1 day	1 day+	1.08 days (1 day + 2 hrs)	2 days
High	0	0+	.08 day (2 hrs)	1 day

a. This configuration category assumes that measures are taken to compensate for the risk associated with early reduced-inventory operations, as explained in Appendix B. If compensatory measures are not taken, these configurations are assigned to the "High" configuration category.

Table 3.2.2-2 Baseline and Thresholds for Time in Risk-Significant Configurations Indicators - BWRs

Configuration Category	Baseline	G/W Threshold	W/Y Threshold	Y/R Threshold
Low	2 days	3 days	12 days	102 days
Medium	0.20 day (5 hrs)	0.29 day (7 hrs)	1 day	10 days
High	0	0+	.08 day (2 hrs)	1 day

Table 3.2.2-3 PWR Shutdown Configurations Risk Classification (Based on a Generic Westinghouse 4-Loop Shutdown PRA Model)

POS				No Maintenance Unavailability	Backup RHR Train Unavailable	Emergency AC Trains Unavailable			Support Cooling Trains Unavailable		Secondary Cooling Trains Unavailable			Emergency Injection Trains Unavailable			Other Trains Unavailable			
Group	Mode	RCS Boundary	Days After Shutdown		RHR	EDG	EDG(2)	One Safety-Related AC Bus	One train of ESW	One train of CCW	One train of AFW	All AFW	All SGs	RWST	SI(2)[a]	Both Sumps	PORV(2)	SG/ PORV	SG/ RWST	SG/ and Both Sumps
Low Inventory Configurations Occurring Very Early (within the first 5 days) in an Outage																				
Depressurized RHR Cooling with Reduced Inventory	Mode 5 Cold shutdown	Intact or isolatable	2	Low	Med	Low	Low	Low	Low	Med	High	High	High	Low	Low	High	Low	High	High	High
Depressurized RHR Cooling with Reduced Inventory	Mode 5 Cold shutdown	vented	< 5	ERI-V[b]	ERI-V[b]						(shaded)	(shaded)	(shaded)	ERI-V[b]			(shaded)	(shaded)	(shaded)	(shaded)
Representative Configurations Occurring in a Typical Outage																				
Pressurized Cooldown	Mode 4 Hot shutdown	Intact	4			Low	Med	Low	Low			(shaded)	(shaded)	Med		Low		(shaded)	(shaded)	(shaded)
Depressurized RHR Cooldown with Normal Inventory	Mode 5 Cold shutdown	Intact	8				Low	Low			Low	Low	Low	Low		Low		High	High	High
Depressurized RHR Cooling with Reduced Inventory	Mode 5 Cold shutdown	Intact or isolatable	12		Low		Low	Low	Low	Low	Med	Med	Med	Low		Low	Low	High	High	High
Depressurized RHR Cooling with Reduced Inventory	Mode 5 Cold shutdown	vented	7	Med	Med	Med	Med	High	Med	Med	(shaded)	(shaded)	(shaded)	High	Med	Med	(shaded)	(shaded)	(shaded)	(shaded)
Depressurized RHR Cooling with Reduced Inventory	Mode 5 Cold shutdown	vented	13	Med	Med	Med	Med	High	Med	Med	(shaded)	(shaded)	(shaded)	High	Med	Med	(shaded)	(shaded)	(shaded)	(shaded)
Refueling Cavity Filled	Mode 6	vented	14								(shaded)	(shaded)	(shaded)			Med	(shaded)	(shaded)	(shaded)	(shaded)
Low Inventory Configurations Occurring Late in a Typical Outage																				
Depressurized RHR Cooling with Reduced Inventory	Mode 5 Cold shutdown	vented	24			Low	Med	Low	Low	Low	(shaded)	(shaded)	(shaded)	Med	Low	Low	(shaded)	(shaded)	(shaded)	(shaded)

Notes: Shaded cells indicate combinations of POS and configuration that are not analyzed, either because the configuration violates the POS definition, or the systems involved play no role in the POS. Blank cells represent configurations whose CCDF < 1.0E-6 per day.

a. In this configuration it is assumed that a makeup pump is available.

Table 3.2.2-4 BWR Shutdown Configurations Risk Classification (Based on NUREG/CR-6166 Results)

POS			No Maintenance Unavailability	Emergency AC/DC Trains Unavailable					Support Cooling Trains Unavailable		
Group	Mode	RCS Boundary		EDG I or II	4 EDG I & II	EDG I & III	One. BAT division	Two BAT divisions	SSW A	SSW C	SSW A & C
POS 4	Hot shutdown	Intact		Low	Med	Low		High		Low	Med
POS 5	Cold shutdown	Vessel head on		Low	Med	Low	Low	High	Low	Low	Med
POS 6	Refueling	Vessel head off (level raised to steam line)									
POS 7	Refueling	Upper pool filled									Low

Note: Blank cells indicate combinations of POS and configuration that are not analyzed, either because the configuration violates the POS definition, or the systems involved play no role in the POS.

POS			No Maintenance Unavailability	Emergency Cooling Trains Unavailable				Other Trains Unavailable			
Group	Mode	RCS Boundary		HPCS	LPCS & HPCS	SP empty	SRVs all	SSW A & HPCS	SSW A & CDS	RHR A and all SRVs	SDC A and SP
POS 4	Hot shutdown	Intact		Low	Low	Med	Med	Med		High	Med
POS 5	Cold shutdown	Vessel head on		Low	Low	High	High	Med	Low	High	High
POS 6	Refueling	Vessel head off (level raised to steam line)				Med					Med

POS 7	Refueling	Upper pool filled				Low		Low	

Note: Blank cells indicate combinations of POS and configuration that are not analyzed, either because the configuration violates the POS definition, or the systems involved play no role in the POS.

Summary of RBPI development Results

Risk Coverage by RBPIs:

- **Risk coverage was assessed using two methods, one based on RAW of risk-significant elements, and the other based on coverage of dominant core damage accident sequences**
- **Table 4.2a shows risk coverage at initiating event/system level using dominant core damage accident sequences from IPE studies for two plants**
  - **Almost all dominant accident sequences are covered by multiple RBPIs**
  - **Elements not covered are potential areas for inspection**
  - **Sequences with no RBPI coverage are not dominant sequences**

Table 4-2a RBPI Coverage of Dominant Full Power Internal Event Core Damage Sequences - BWR 3/4 Plant 18 (IPE Data Base Results)

IE RBPI

Industry-Wide Trending

System RBPI

ACCIDENT SEQUENCE FAILURES

SEQ	CDF	INITIATOR					
1	5.28E-07	T-LOOP	AC	EAC			
2	1.60E-07	S1	HUM				
3	2.70E-08	T-LOOP	HP1	HUM	AC		
4	2.21E-08	T-LOOP	AC	EAC			
5	2.05E-08	T-ATWS	RPS	CONDA	HUM		
6	1.80E-08	T-LOOP	HPCI(HPCS)	RCIC	AC	EAC	
7	1.34E-08	T-LOOP	HP1	HUM	AC		
8	1.16E-08	T-RX	ADS	DC			
9	1.10E-08	T-LOOP	HPCI(HPCS)	RCIC	HP1	HUM	AC
10	8.96E-09	T-LOOP	HP1	LPCI	SPC	AC	
11	8.12E-09	T-RX	DC				
12	7.76E-09	T-ATWS	RPS	LPCI	CS	CONDA	HUM
13	7.59E-09	T-LOOP	SPC	HUM	AC		
14	7.00E-09	T-LOOP	HP1	SPC	HUM	AC	
15	6.90E-09	T-LOOP	HP1	SPC	HUM	AC	
16	6.72E-09	T-LOOP	HP1	HUM	AC		
17	6.13E-09	T-ATWS	RPS	CONDA	HUM		
18	5.83E-09	T-ATWS	RPS	CONDA	HUM		
19	5.77E-09	T-LOOP	HPCI(HPCS)	RCIC	HP1	HUM	AC
20	5.66E-09	A	LPCI	CS			
21	5.53E-09	T-LOOP	HPCI(HPCS)	RCIC	HUM	AC	
22	5.43E-09	T-LOOP	HPCI(HPCS)	RCIC	HP1	HUM	AC
23	5.10E-09	T-RX	HPCI(HPCS)	RCIC	HP1	HUM	
24	5.02E-09	S2	HPCI(HPCS)	HUM			
25	4.60E-09	A	SPC	AC			
26	4.46E-09	T-LOOP	HP1	LPCI	SPC	AC	
27	4.44E-09	T-LOOP	LPCI	SPC	HUM	AC	
28	3.88E-09	T-ATWS	RPS	HP1	CONDA	HUM	
29	3.83E-09	S1	HPCI(HPCS)	HUM			
30	3.78E-09	T-LOOP	SPC	HUM	AC		
31	3.62E-09	T-ATWS	RPS	HPCI(HPCS)	CONDA	HUM	
32	3.46E-09	T-LOOP	HP1	HUM	AC		
33	3.42E-09	T-LOOP	SPC	HUM	AC		
34	3.38E-09	T-RX	HPCI(HPCS)	RCIC	MFW	HP1	HUM

Summary of RBPI development Results

Validation and Verification:

- The purpose of this effort was to show that RBPIs can be calculated using readily available data and risk models consistent with current ROP philosophy

- RBPIs for full power, internal events were tested by evaluating plant-specific data for 23 plants over three-year period (1997-1999)

- A "face validity" approach was used

- Differences between ROP PIs and RBPIs are known and make sense from a risk perspective

  - More precise accounting for risk-significant design features of plants
  - More plant-specific thresholds
  - More appropriate accounting for risk impact of fault exposure time

- Since models/data in these tables have not been formally peer reviewed, plant-specific inferences regarding "green" or "non-green" performance from these calculations would be inappropriate.

Key Implementation Issues

- Are any additional performance indicators needed in ROP?
- Is the number of potential new performance indicators appropriate?
- Do data sources for RBPIs exist and have sufficient quality for use in ROP?
- Will Rev. 3i SPAR models be available for setting plant-specific thresholds for all plants?
- Will LERF models be available for setting baseline performance and thresholds for mitigating and containment systems?

Alternative Approaches for RBPI determination

- Comments received regarding the number of PIs being "excessive".

- Reexamined bases for current selection:

  - based on devolving risk
  - thresholds set at data collection level
  - impacts based on sequence effects

- Devolved risk logic to cornerstone level and functions within cornerstone (Fig. 1 & 2).

- Separated thresholds from inputs. Thresholds set on ΔCDF of all inputs to a functional group (Fig. 3).

- Devised hierarchy of groups. (Fig. 3b).

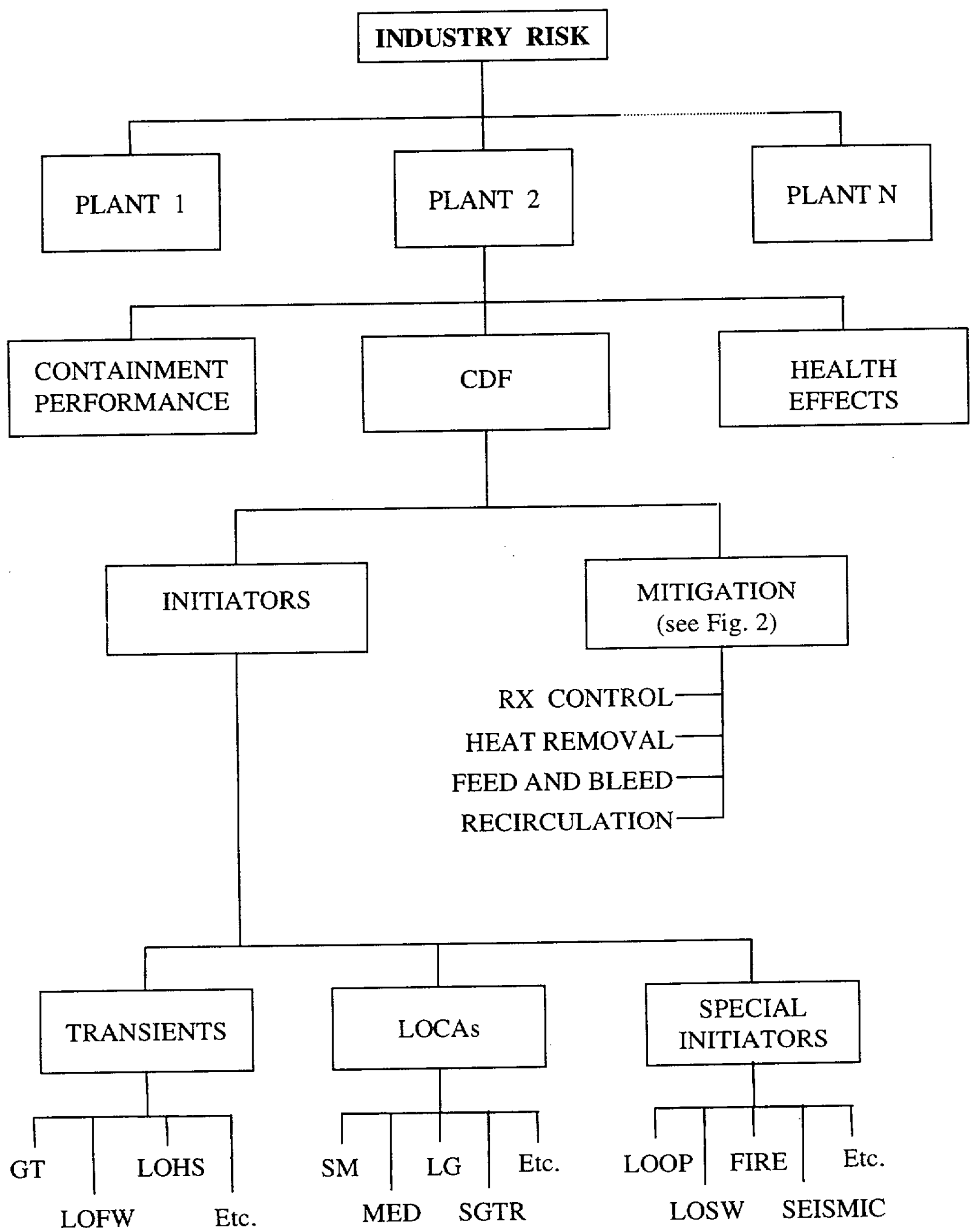
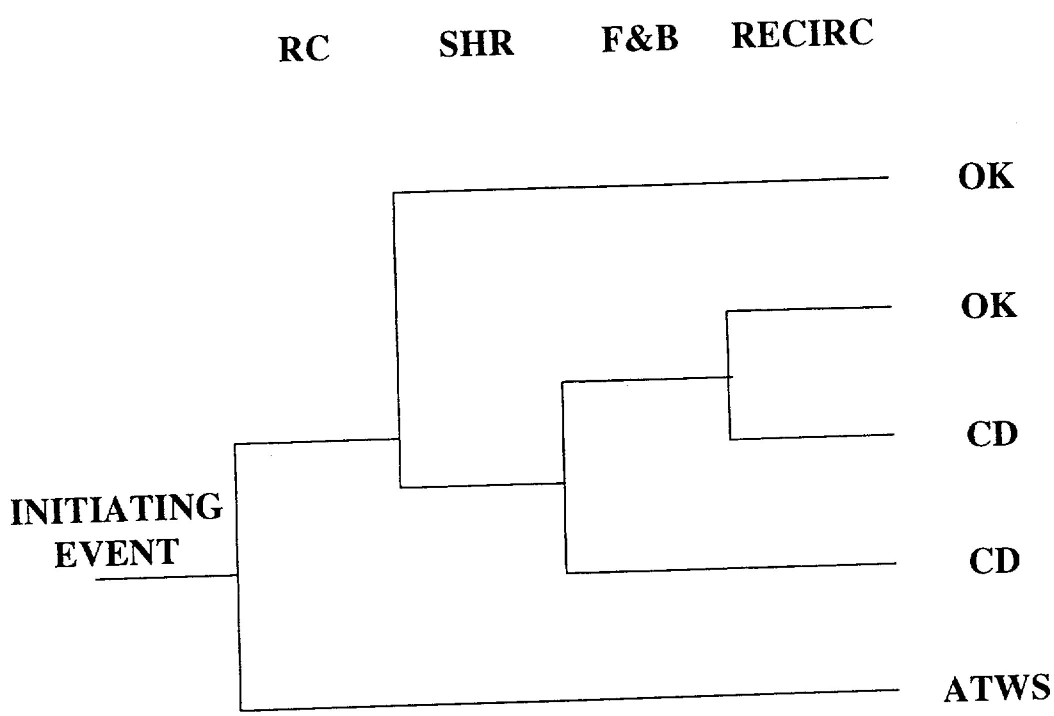

INDUSTRY RISK
PLANT 1
PLANT 2
PLANT N
CONTAINMENT PERFORMANCE
CDF
HEALTH EFFECTS
INITIATORS
MITIGATION (see Fig. 2)
RX CONTROL
HEAT REMOVAL
FEED AND BLEED
RECIRCULATION
TRANSIENTS
LOCAs
SPECIAL INITIATORS
GT
LOFW
LOHS
Etc.
SM
MED
LG
SGTR
Etc.
LOOP
LOSW
FIRE
SEISMIC
Etc.

FIGURE 1



RC: REACTIVITY CONTROL
SHR: SECONDARY HEAT REMOVAL
F&B: FEED AND BLEED
RECIRC: RECIRCULATION

FIGURE 2

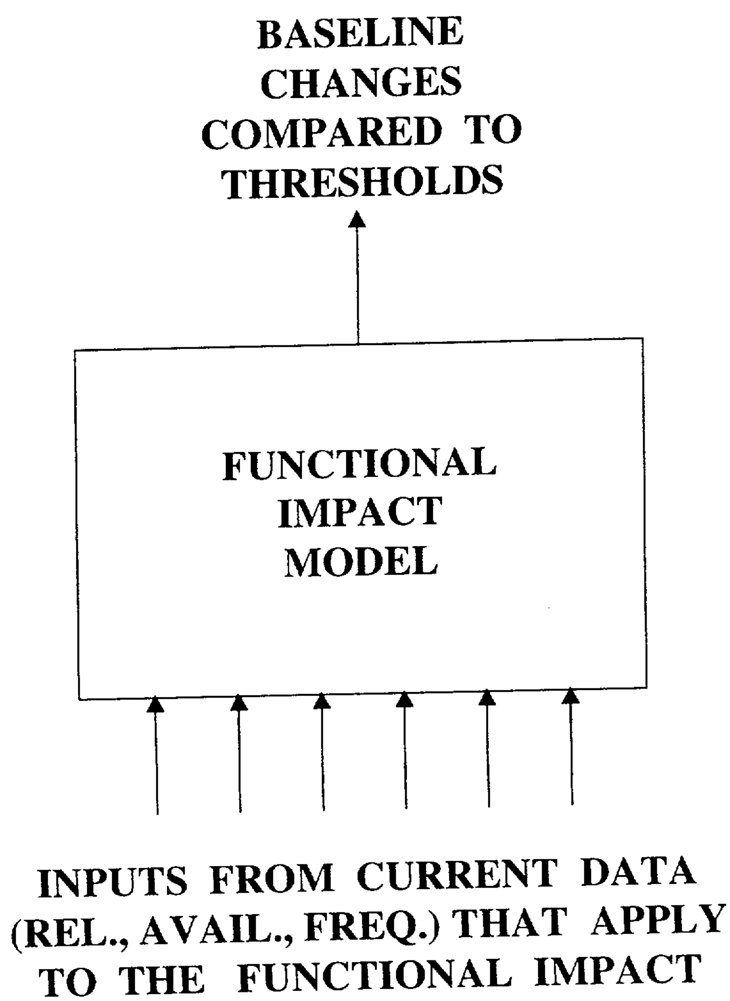

BASELINE CHANGES COMPARED TO THRESHOLDS
FUNCTIONAL IMPACT MODEL
INPUTS FROM CURRENT DATA (REL., AVAIL., FREQ.) THAT APPLY TO THE FUNCTIONAL IMPACT

FIGURE 3

Potential Indicator Hierarchy

- CORNERSTONE LEVEL - One indicator for IE and mitigating systems for at power operation.

- FUNCTIONAL LEVEL - 3-5 indicators for each cornerstone.

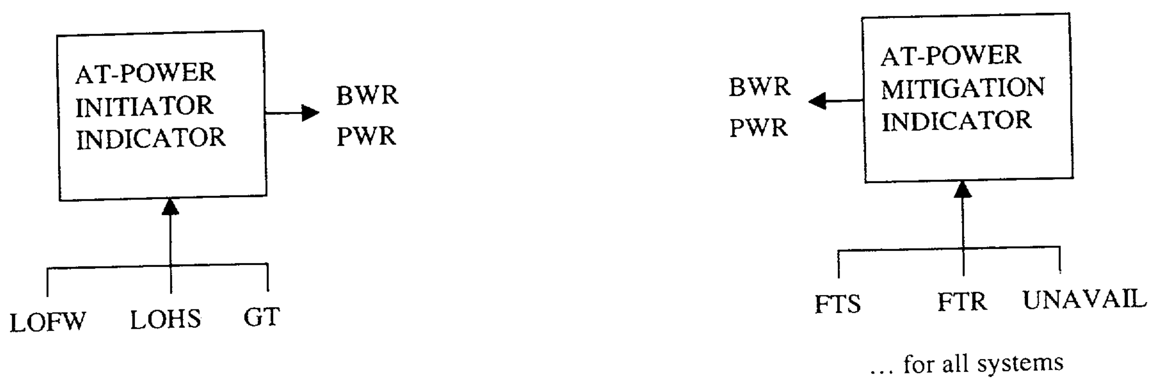
  - Grouped by initiator
  - Grouped by mitigating system/function

- COMPONENT/TRAIN LEVEL

  - RBPIs in Phase-1 report
  - System/function indicators grouped by initiating events

POTENTIAL LEVELS OF RBPIs

CORNERSTONE LEVEL



FUNCTIONAL LEVEL

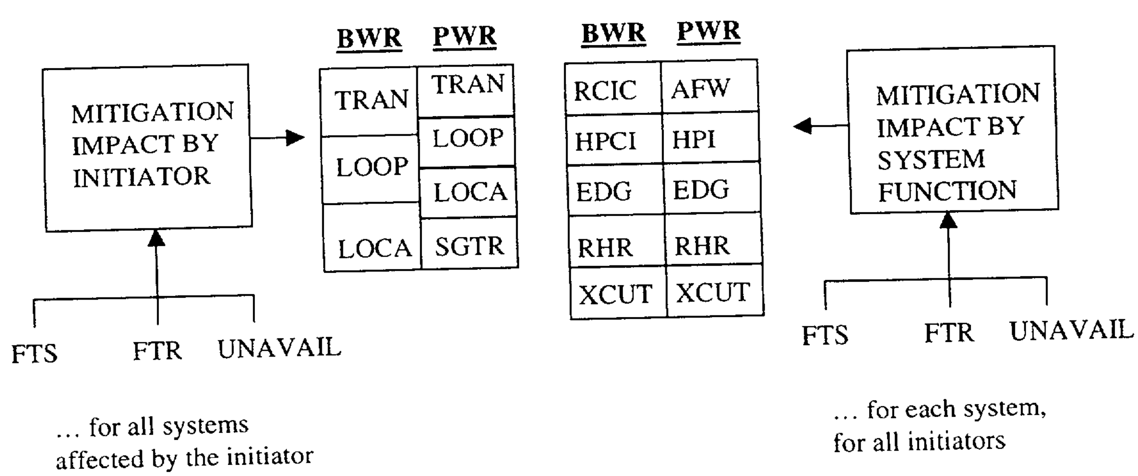


FIGURE 3b

Benefits/Limitations of Potential Alternate RBPIs

Cornerstone Level

- Benefits:
  - Single indicator for each cornerstone indicates overall performance at highest level
  - Takes into account intra- and inter- system impacts of performance in different areas (reliability vs availability, train vs system, and system vs. system)
- Limitations:
  - Causes of >green performance not directly known without further breakdown of indicator model, but it can be done practically

Benefits/Limitations of Potential Alternate RBPIs

Functional Level

- **Benefits:**
  - Fewer number of indicators (<6) for each cornerstone
  - Accounts for intra- and inter-system impacts
  - Can be grouped by either initiators (LOOP, TRANS, LOCA, etc) or by system functions (heat removal, emergency power, etc.)

- **Limitations:**
  - Doesn't directly provide cornerstone-level performance (still need to use Action Matrix)
  - Causes of >green performance not directly known, but can be derived by devolving indicators into parts.

Benefits/Limitations of Potential Alternate RBPIs

Component/Train Level

- Benefits:
  - Broadest evaluation of individual performance attributes
  - Causes of >green performance readily identified
  - Greater similarity to current indicators

- Limitations:
  - Intra- and Inter-system impacts not accounted for (synergies of impacts can be conservative or non-conservative depending on accident sequence logic)
  - Nearly doubles current number of PIs
  - Requires thresholds set for each data input

Summary of Industry Inputs

- Industry supports movement toward RBPIs
  - Moving toward plant-specific thresholds is appropriate
  - There is a need for an integrated approach
    - Design-basis versus risk-based approach
    - Impact on Action Matrix of additional RBPIs

- Any change/addition to existing PIs must add value to inspection, assessment and enforcement process
  - Avoid unnecessary burden
  - Improve understanding of risk-significant issue
  - Reduce inspection activity

- Unavailability issues for mitigating systems must be resolved
  - Design-basis versus risk-based
  - Credit for operator action
  - Cascading of support systems

- Data gathering and reporting under 50.9 requirements is a major impediment

- Shutdown RBPIs may be more appropriate for the SDP
  - Proposed RBPIs are not easily explained or understood

Phase-1 RBPI Development Results

We are asking ACRS to provide feedback (via a letter) on:

- Potential benefits of RBPIs to the Reactor Oversight Process (ROP)
- Technical feasibility/adequacy of RBPIs
- Alternative approaches for developing RBPIs in response to stakeholders concern over total number of RBPIs

Phase-1 RBPI Development Results

Back-up Information

Industry-Wide Trending

- Industry-wide trending includes all proposed RBPIs plus risk-significant IEs and CCF events that are impractical to monitor on a plant-specific basis.
  - Table ES-2 provides a summary of proposed trends
- Industry-wide trending provides:
  - Measures of ROP effectiveness.
  - Provides feedback to ROP to adjust technical emphasis and overall inspection frequencies.
  - Input to agency Strategic Plan Performance Measures

Table ES-2 Summary of Phase-1 Performance Areas Proposed for Industry-Wide Trending

Safety Cornerstone	Industry-Wide Trend
Initiating Event	**Full Power:** – All proposed IE RBPIs listed in Table ES-1 – Internal flooding – Initiators evaluated as ASPs – Loss of instrument/control air (for BWRs and PWRs) – LOOP – Loss of vital AC bus – Loss of vital DC bus – Small LOCA (including very small LOCA) – SGTR – Stuck open safety/relief valves **Shutdown:** – LOOP during shutdown modes – Loss of RHR during shutdown modes – Loss or diversion of RCS inventory during shutdown modes leading to loss of RHR – Loss of RCS level control (during transition to mid-loop) leading to loss of RHR (for PWRs only) **Fire:** – Fire events in risk-significant fire areas
Mitigating System	– All proposed mitigating system RBPIs listed in Table ES-1 – CCF events for AFW pumps – CCF events for Diesel Generators – Total CCF events
Barriers	None

Table 1 Cornerstone Level RBPIs

	Baseline CDF	Green	White	Yellow	Red
BWR Plant 18	2.0E-05	< 2.1E-05	<3.0E-05	< 1.2E-04	> 1.2E-04
All Systems (EPS, HPCI, RCIC, RHR)			2.5E-5 (W)		
All Initiators Combined		2.0E-5 (G)			
	Baseline CDF	**Green**	**White**	**Yellow**	**Red**
PWR Plant 23	3.4E-05	< 3.5E-05	< 4.4E-05	< 1.3E-04	> 1.3E-04
All Systems (AFW, EPS, HPI/PORV, RHR)			3.7E-5 (W)		
All Initiators Combined		3.4E-5 (G)			

NOTES:
1. (G) - Calculated CDF falls within the 'GREEN' performance band.
2. (W) - Calculated CDF falls within the 'WHITE' performance band.
3. Calculated CDF generated by quantifying model with all of the applicable failure values (e.g., FTS, FTR, UA) currently used for individual RBPIs.

Table 2 Functional Level Mitigation RBPI by Initiator

BWR Plant 18					
Baseline Plant CDF (2.0E-05)	**Baseline CDF**	**Green**	**White**	**Yellow**	**Red**
Baseline LOCA Group (SLOCA, MLOCA, LLOCA) CDF	1.6E-08	< 1.0E-06	< 1.0E-05	< 1.0E-04	> 1.0E-04
- Front Line Systems (RCIC, HPCI, RHR) & Components		3.7E-08 (G)			
Baseline LOOP/SBO Group CDF	1.8E-05	< 1.9E-05	< 2.8E-05	< 1.2E-04	> 1.2E-04
- Front Line Systems (RCIC, HPCI, EPS, RHR) & Components			2.2E-05 (W)		
Baseline TRANSIENT Group (TRAN, LDCB, LOSWS) CDF	2.2E-06	< 3.2E-06	< 1.2E-05	< 1.0E-04	> 1.0E-04
- Front Line Systems (RCIC, HPCI, RHR) & Components		2.4E-06 (G)			
PWR Plant 23					
Baseline Plant CDF (3.4E-05)	**Baseline CDF**	**Green**	**White**	**Yellow**	**Red**
Baseline LOCA Group (SLOCA, MLOCA, LLOCA) CDF	2.5E-07	< 1.2E-06	< 1.0E-05	< 1.0E-04	> 1.0E-04
- Front Line Systems (AFW, HPI/PORV, RHR) & Components		2.0E-07 (G)			
Baseline LOOP/SBO Group CDF	1.6E-05	< 1.7E-05	< 2.6E-05	< 1.2E-04	> 1.2E-04
- Front Line Systems (AFW, HPI/PORV, EPS, RHR) & Components		1.0E-05 (G)			
Baseline TRANSIENT Group (TRAN, LDCA, LOCCW, LOSWS) CDF	1.2E-05	< 1.3E-05	< 2.3E-05	< 1.1E-04	> 1.1E-04
- Front Line Systems (AFW, HPI/PORV, RHR) & Components			1.9E-05 (W)		
Baseline SGTR Group CDF	4.2E-06	< 5.2E-06	< 1.4E-05	< 1.0E-04	> 1.0E-04
- Front Line Systems(AFW, HPI/PORV, RHR) & Components		4.0E-06 (G)			

NOTES:
1. (G) - Calculated CDF falls within the 'GREEN' performance band.
2. (W) - Calculated CDF falls within the 'WHITE' performance band.

Table 3 Functional Level Mitigation RBPI by System

	Baseline CDF	Green	White	Yellow	Red
BWR Plant 18	2.0E-05	< 2.1E-05	< 3.0E-05	< 1.2E-04	> 1.2E-04
EPS		2.0E-5 (G)			
HPCI			2.6E-5 (W)		
RCIC		2.0E-5 (G)			
RHR		2.0E-5 (G)			
Component Groups (AOVs, MOVs, MDPs)		2.0E-5 (G)			
	Baseline CDF	**Green**	**White**	**Yellow**	**Red**
PWR Plant 23	3.4E-05	< 3.5E-05	< 4.4E-05	< 1.3E-04	> 1.3E-04
AFW			4.3E-5 (W)		
EPS		2.9E-5 (G)			
HPI & PORVs		3.4E-5 (G)			
RHR		3.4E-5 (G)			
Component Groups (AOVs, MOVs, MDPs)		3.4E-5 (G)			

NOTES:

1. (G) - Calculated CDF falls within the 'GREEN' performance band.
2. (W) - Calculated CDF falls within the 'WHITE' performance band.
3. Calculated CDF generated by quantifying model with all of the applicable failure values (e.g., FTS, FTR, UA) currently used for individual RBPIs.

Figure 2.1 RBPI Development Process

Sheet 1

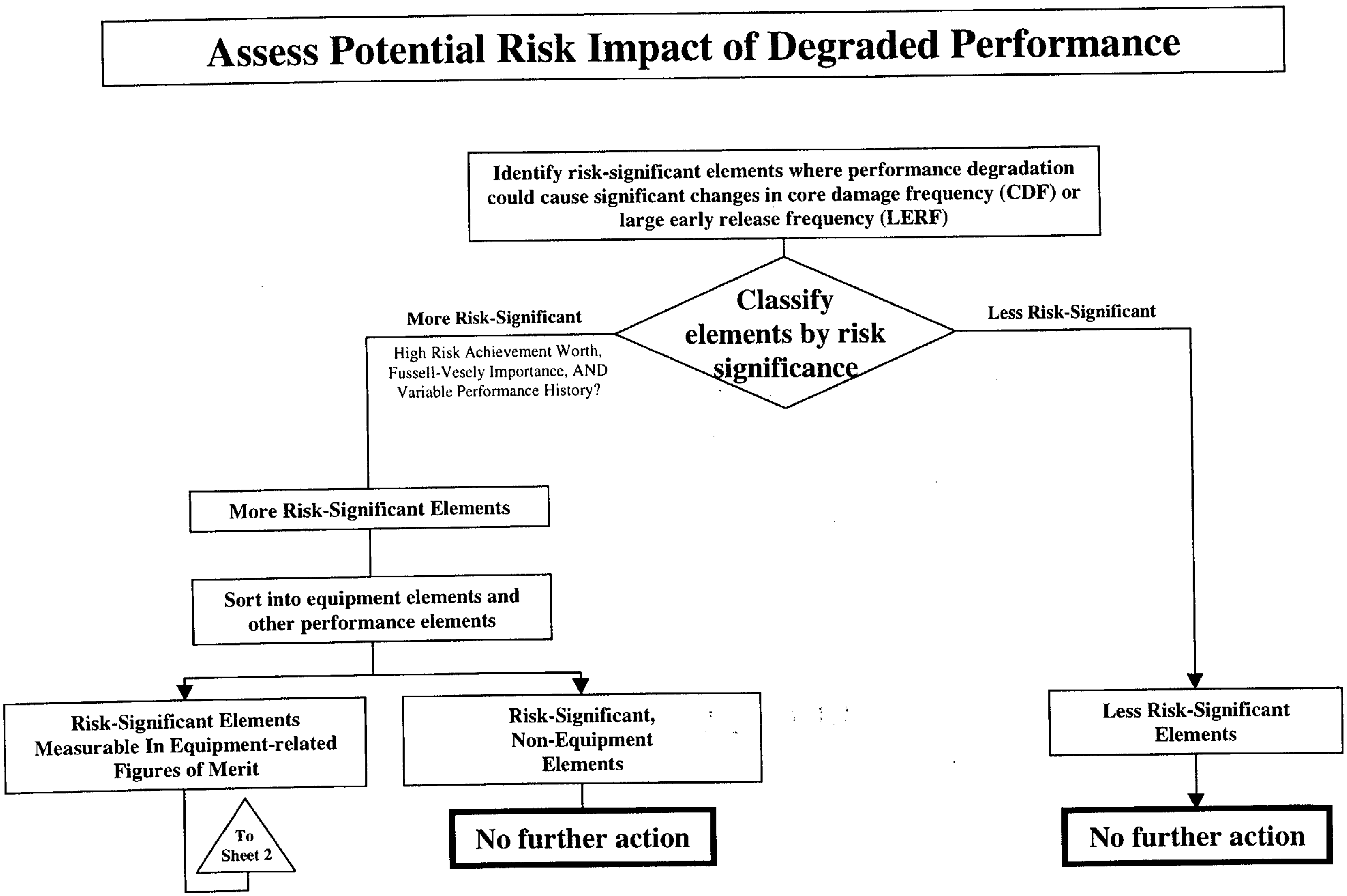


Figure 2.1 RBPI Development Process

Sheet 2

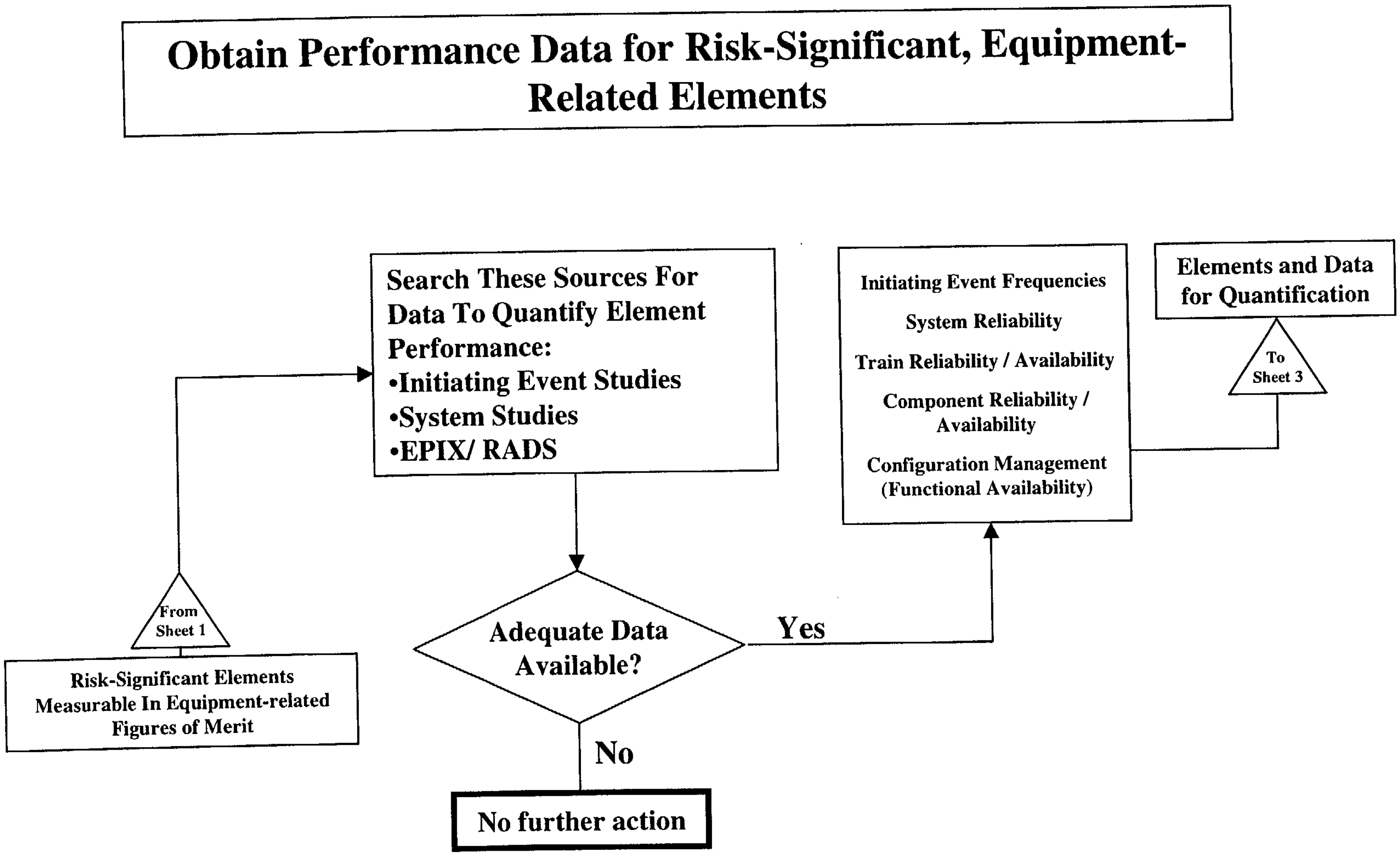


Figure 2.1 RBPI Development Process

Sheet 3

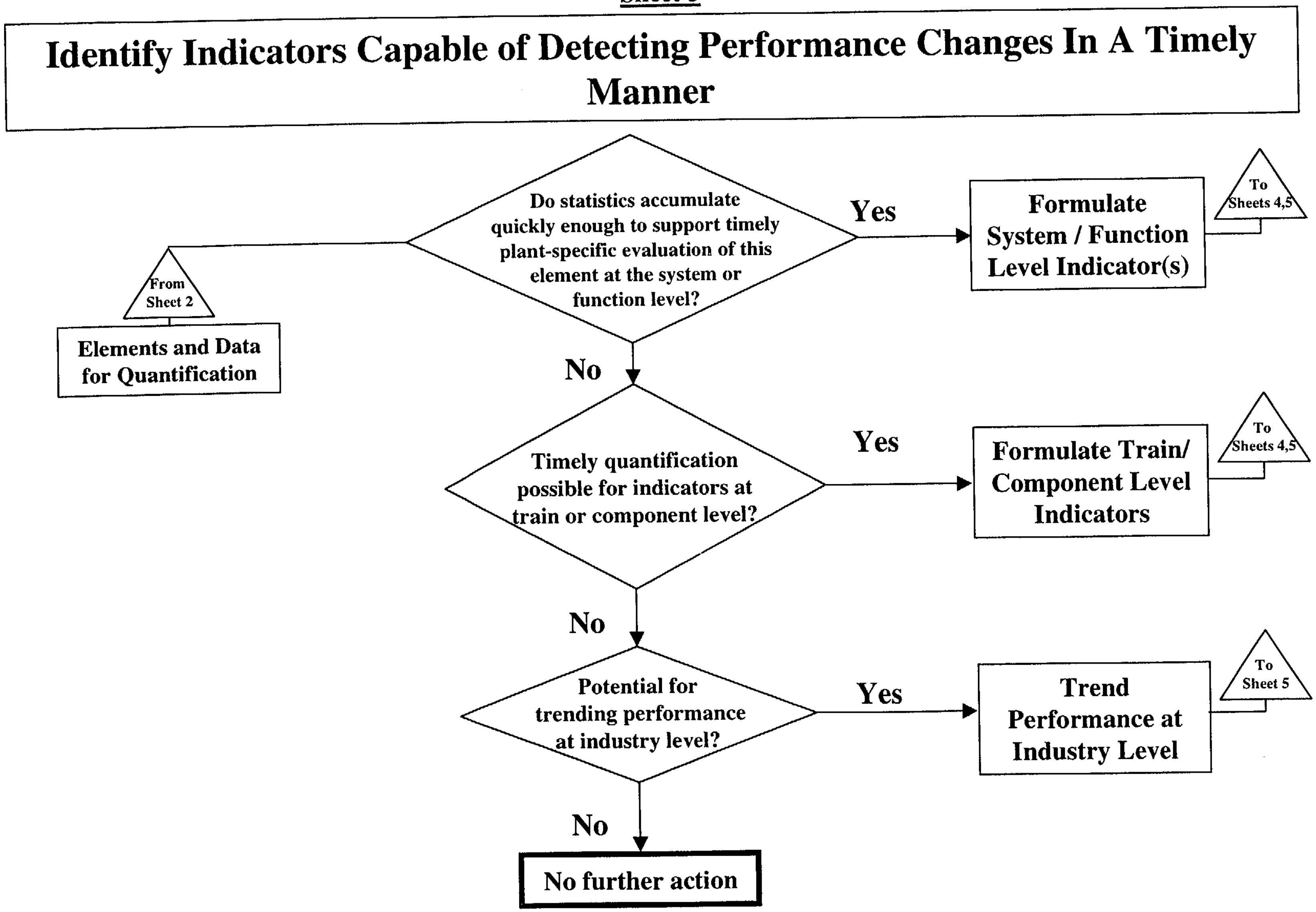


Figure 2.1 RBPI Development Process

Sheet 4

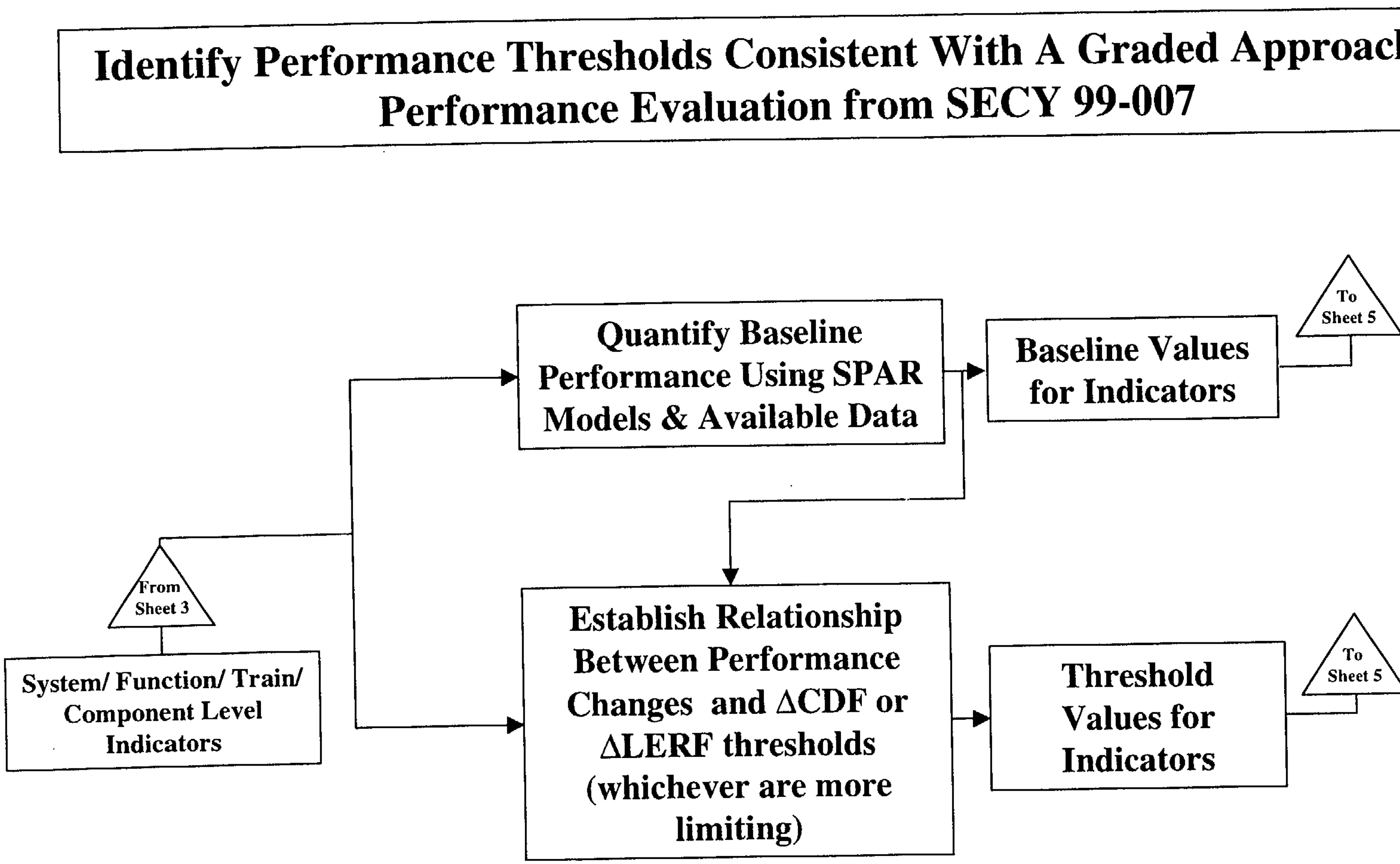
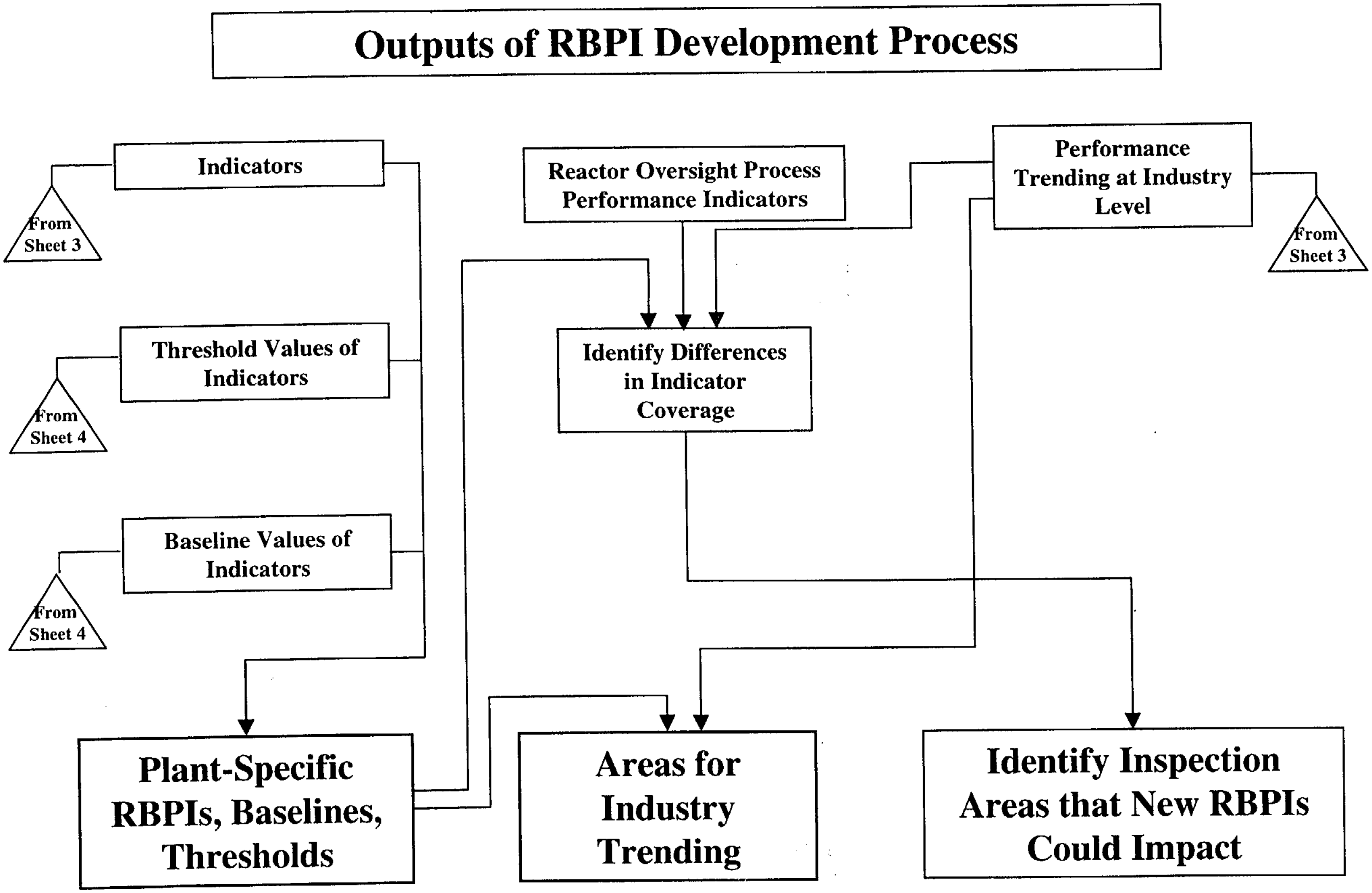


Figure 2.1 RBPI Development Process

Sheet 5



MAY 10, 2001

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
FINAL SAFETY EVALUATION REPORT
ARKANSAS NUCLEAR ONE, UNIT 1

ANO-1 LICENSE RENEWAL APPLICATION

Introduction	PT Kuo
Overview	Robert Prato
License Renewal Application	Garry Young (Entergy)
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Scoping	
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Open Items	
Aging Management Programs	Robert Prato
Conclusion	Robert Prato

OVERVIEW

- Unit description

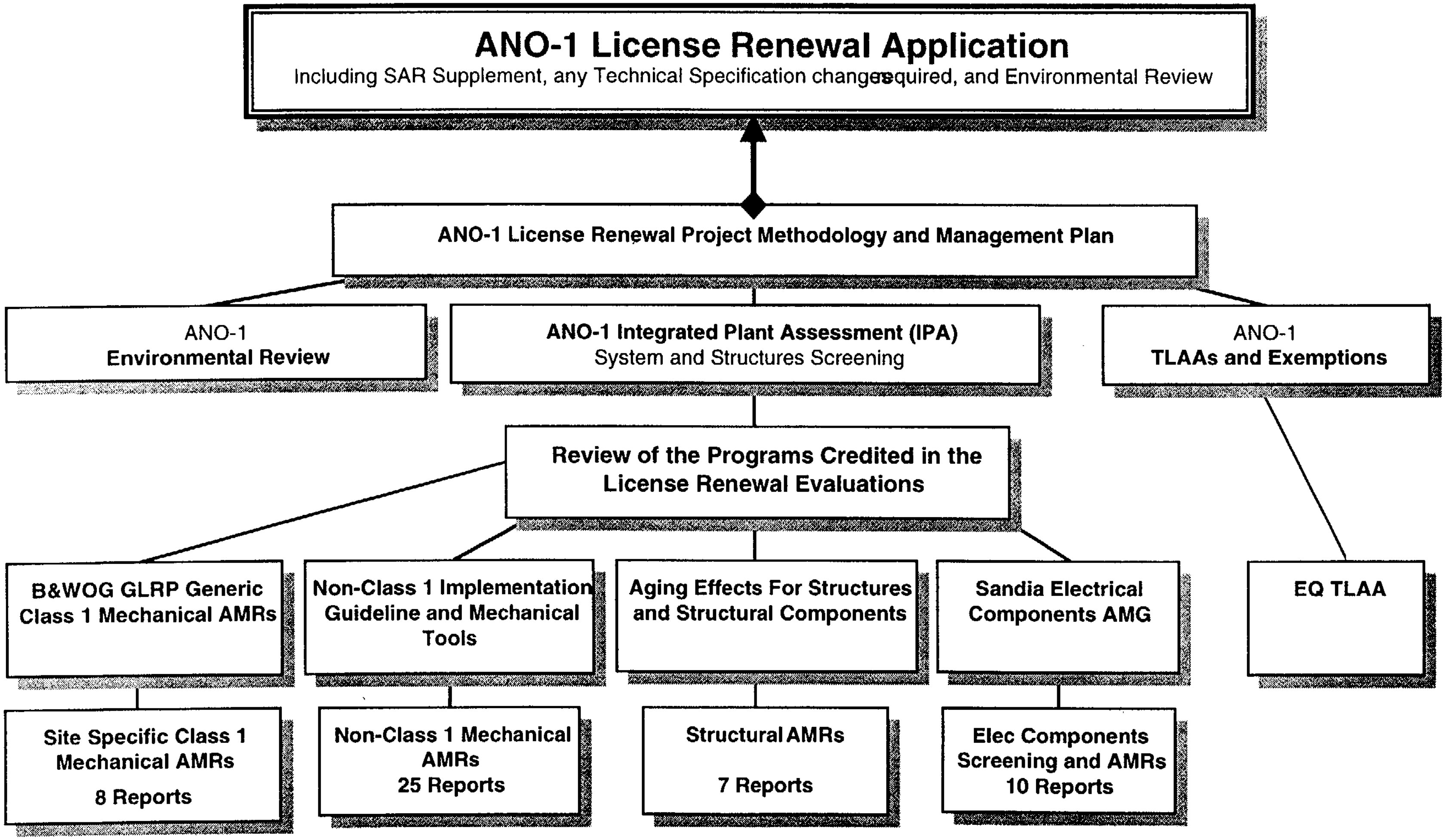
- ANO-1 site comparison with Oconee

- ANO-1 application comparison with Oconee application

- Safety evaluation reports Open Items

ANO-1 License Renewal Application

Document Hierarchy



LRA - Scoping

- Scoping performed using guidance from NEI 95-10

  - Safety-Related or 10CFR54.4(a)(1) SSCs identified from component level Q-List and SAR summary level Q-List

  - Non- Safety-Related or 10CFR54.4(a)(2) SSCs identified from the SAR and design documents

  - Commission regulations or 10CFR54.4(a)(3) SSCs identified from the SAR and design documents [includes fire protection, environmental qualification, pressurized thermal shock, ATWS, and station blackout]

LRA - Screening

- Screening performed using guidance from NEI 95-10
  - Identified "passive" SCs that perform an intended function without moving parts or a change in configuration or properties
  - Identified passive SCs that are not subject to periodic replacement based on qualified life
- Screening of mechanical Class 1 components performed using B&WOG topical reports, mechanical non-Class 1 components performed on plant specific basis
- Screening of electrical components and structural performed on plant specific basis

LRA - Aging Effects

- Identification of applicable aging effects of mechanical components performed using system based approach

  - mechanical Class 1 components identified using B&WOG topical reports,

  - mechanical non-Class 1 components identified on plant specific basis

- Identification of applicable aging effects of electrical components performed using spaces approach

- Identification of applicable aging effects of structures and structural components performed using commodity approach

LRA - Aging Management Programs

- New programs included 7 major categories (i.e., buried pipe inspection, electrical component inspection, pressurizer examinations, reactor vessel internals aging management, spent fuel pool monitoring)

- Existing or modified programs included 22 major categories (i.e., ASME Section XI, boric acid corrosion prevention, chemistry control, preventive maintenance, reactor vessel integrity, steam generator integrity)

LRA - Time Limited Aging Analyses (TLAAs)

- TLAAs identified and evaluated included:
  - Reactor Vessel Neutron Embrittlement
  - Metal Fatigue
  - Environmental Qualification
  - Reactor Building Tendon Prestress
  - Boraflex in Spent Fuel Pool Racks

LRA - Conclusions

- ANO-1 LRA utilized a number of lessons learned from Oconee and the industry
- Number of NRC requests for additional information substantially reduced
- Number of SER Open Items significantly reduced
- License renewal process is stable and predictable

SER - Scoping

- Originally designed to barriers for the release of fission products
- Design basis reconstitution
- Incorporated Lessons Learned
- Applicable aging effects
- Corrective Actions

SER - Scoping Open Items

Open Item 2.3.2.6.2-1	The applicant did not identify flow control as an intended function of the in-line orifice that controls the injection of sodium hydroxide for pH control.
Open Item 2.3.3.2.2.-1	The applicant did not identify the FP jockey pump, carbon dioxide systems, fire hydrants, the water supply to the low level radwaste building FP system, and the piping to the manual hose station as being within the scope of license renewal, and subject to an AMR.

SER - Aging Management Review

- Aging Effects

  - void swelling in the rx vessel
  - reduction in fracture toughness of RVI CASS components
  - cracking and loss of material of letdown cooler tubing
  - loss of material of external ferritic surfaces
  - cracking of RVI non-bolted items
  - cable trays and conduits located inside/outside of containment
  - vibrational loading of HVAC system

- Intended Function - heat transfer function for heat exchanger,

SER - Aging Management Review (cont.)

- AMR -
  - service water piping
  - tendon gallery
  - pressurizer spray head
  - heater bundle penetration welds
  - trash racks

- Aging Mangement
  - performance monitoring used to manage fouling
  - cracking of Alloy 600 and Alloy 82/182
  - Small Bore Piping management by a risk-informed method

SER - Aging Management Review Open Items

Open Item 3.3-1 - The applicant did not provide a sufficient summary description for 11 of the selected aging management programs that will be included in the FSAR supplement.

Open Item 3.3.7.2-1 - The applicant did not identify an aging management program for buried (inaccessible) medium-voltage cables, exposed to ground water that are within the scope of license renewal and subject to an AMR.

SER - Time-limited Aging Analyses

- Fatigue
- Fracture Toughness RVIs BAW 2248
- Flaw Growth
- Neutron Embrittlement of Reactor Vessel
- Pressurized Thermal Shock
- Containment Prestress Tendon pre-stress
- Reactor Building Liner Plate Fatigue Analysis
- Reactor Vessel Underclad Cracking
- Reactor Vessel Incore Instrumentation Nozzle

SER - Time-limited Aging Analyses Open Items

Open Item 4.5.2.-1	The applicant did not demonstrate the adequacy of the existing prestressing forces in the containment tendons by providing the trend lines for the containment post tensioning system for the period of extended operation.
Open Item 4.5.2.-1	The ANO-1 Boraflex monitoring program is similar to the ONS program. Data gathered during the summer of 2000 identified the fact that boraflex depletion rate would not provide an adequate shut-down margin during the current licensing term and, therefore, determined boraflex to no longer be a TLAA. The staff believes that boraflex depletion is still a TLAA.

AGING MANAEMENT PROGRAMS

NEW ACTIVITIES	
1	BURIED PIPE INSPECTION
2	ELECTRICAL COMPONENT INSPECTION
3	HEAT EXCHANGER MONITORING
4	PRESSURIZER EXAMINATIONS
5	REACTOR VESSEL INTERNALS AGING MANAGEMENT
6	SPENT FUEL POOL MONITORING
7	WALL THINNING INSPECTION
EXISTING ACTIVITIES	
1	ALLOY-600 AGING MANAGEMENT
2	ALTERNATE AC DIESEL GENERATOR TESTING AND INSPECTIONS
3	ASME SECTION XI INSERVICE INSPECTION (including IWB, IWC, IWD, IWE, IWF, IWL and "augmented" inspections as well as small bore piping and nozzle inspections)
4	BOLTING AND TORQUING ACTIVITIES
5	BORIC ACID CORROSION PREVENTION
6	CHEMISTRY CONTROL (including primary chemistry, secondary chemistry, auxiliary systems chemistry, diesel fuel monitoring and service water chemical control)
7	CRDM NOZZLE AND OTHER VESSEL CLOSURE PENETRATION INSPECTION
8	FIRE PROTECTION
9	FLOW ACCELERATED CORROSION PREVENTION
10	INSPECTION AND PREVENTIVE MAINTENANCE OF THE ANO-1 POLAR CRANE
11	INSTRUMENT AIR QUALITY
12	LEAKAGE DETECTION IN REACTOR BUILDING
13	MAINTENANCE RULE
14	OIL ANALYSIS
15	PREVENTIVE MAINTENANCE
16	REACTOR BUILDING LEAK RATE TESTING
17	REACTOR BUILDING SUMP CLOSEOUT INSPECTION
18	REACTOR VESSEL INTEGRITY
19	SERVICE WATER INTEGRITY
20	STEAM GENERATOR INTEGRITY
21	ANNUAL EMERGENCY COOLING POND SOUNDING
22	BATTERY QUARTERLY SURVEILLANCE
23	CONTROL ROOM VENTILATION TESTING
24	CORE FLOOD TANK MONITORING
25	EMERGENCY DIESEL GENERATOR TESTING AND INSPECTIONS
26	EMERGENCY FEEDWATER PUMP TESTING
27	NAOH TANK LEVEL MONITORING
28	SPENT FUEL POOL LEVEL MONITORING

1.4 Summary of Open Items

Upon completing its initial review, the staff identified and documented six open items in an SER dated January 10, 2001. The applicant responded to each of the open items by providing additional information in a letter to the NRC dated March 14, 2001. The following describes each of the six open items, the applicant's response to each item, and the staff's evaluation of the applicant's response.

- Open Item 2.3.2.6.2-1 - The ANO-1 UFSAR, Section 6.2.2.1, identifies an in-line flow orifice as being necessary to ensure the proper sodium hydroxide injection rate for pH control. This flow orifice was not identified as a component of the sodium hydroxide system that was subject to an AMR for its flow control intended function in Table 3.3-6 of the LRA.

  In response to this concern, the applicant added the flow control function for the sodium hydroxide in-line flow orifice to its AMR. This flow orifice is constructed of stainless steel, and is susceptible to cracking and loss of material. The inspection activities used to manage similar applicable aging effects of sodium hydroxide stainless steel components will be used to manage the aging of the in-line flow orifice for the flow control intended function. Aging management activities will be completed as part of the new ASME, Section XI, ISI augmented inspections activities evaluated in this SER, Section 3.3.1.4.9. This information was documented in a letter to the NRC staff dated March 14, 2001. The staff finds this resolution to Open Item 2.3.2.6.2-1 acceptable.

- Open Item 2.3.3.2.2-1 - The applicant does not include the fire protection (FP) jockey pump, carbon dioxide systems, fire hydrants, the water supply to the low level radwaste building FP system, and the piping to the manual hose station (located downstream of FS-43) as being within the scope of license renewal and subject to an AMR. The staff requested additional information for the exclusion of these components; however, at the time the initial SER was issued, the applicant had not provided sufficient justification for the exclusion of these components.

  In a public meeting with the applicant that took place on March 7, 2001, the applicant presented its position as to why the FP jockey pump, carbon dioxide systems, fire hydrants, the water supply to the low level radwaste building FP system, and the piping to the manual hose station (located downstream of FS-43) are not included in the applicant's CLB (as documented in the applicant's F-list) in accordance with the requirements of 10 CFR 50.48. The applicant explained that each of these components is maintained to the National Fire Protection Association standards, and provided a technical justification as to why these components are not required for safe shutdown consistent with General Design Criteria III. The staff presented its position that the requirements of10 CFR 50.48 go beyond safe shutdown, and a number of components beyond those required by GDC III are required by 10 CFR 50.48. As a result of this meeting, the applicant agreed to add the jockey pump and fire hydrants to the scope of SCS subject to an AMR and to its F-list consistent with the requirements of 10 CFR 50.48. At the same time, the applicant provided sufficient justification for not including

the carbon dioxide systems, the water supply to the low level radwaste building FP system, and the piping to the manual hose station to the scope of components required by 10 CFR 50.48 for ANO-1. This information was documented in a letter to the NRC dated March 14, 2001. The staff had no additional concerns relating to the scope of FP components subject to an AMR, therefore, this item is considered closed.

- Open Item 3.3-1 - The staff reviewed the applicant's summary descriptions of the aging management programs (AMPs), and the evaluations of the time-limited aging analyses (TLAAs) provided by the applicant in Appendix A, "Safety Analysis Report Supplement," of the LRA, to ensure that they are consistent with the requirements of 10 CFR 54.21(d). The staff identified a number of summary descriptions of AMPs and TLAA evaluations that needed additional information to meet the intent of 10 CFR 54.21(d). The additional information needed include the following:

  - FSAR Item 3.3.1.2.3 - In its revised summary description of Section 16.0 of the FSAR Supplement, the applicant added a summary description of the quality assurance AMP to its FSAR Supplement. This summary description contains an adequate description of the corrective action program that specifically describes corrective actions, the confirmation process, and the administrative controls consistent with 10 CFR Part 50, Appendix B, as it applies to license renewal in accordance with 10 CFR 54.21(d). The staff finds the revised summary description as submitted by the applicant in a letter to the NRC dated March 14, 2001, acceptable.

  - FSAR Item 3.3.1.3.3 - In its revised summary description of Section 16.2.13 of the FSAR Supplement for the Maintenance Rule program, the applicant clarified that this program only applies to external surfaces of the SCS that are managed by this AMP. The staff finds the revised summary description as submitted by the applicant in a letter to the NRC dated March 14, 2001, acceptable.

  - FSAR Item 3.3.1.4.1.3 - A review of the LRA, the applicant's responses to the staff's request for additional information, and the programs credited with managing the aging of fire protection systems buried piping, the staff verified that buried pipe inspection program is not credited, and is not needed to manage the applicable aging effects. The staff finds that no change to Section 16.1.1 of the FSAR Supplemented, as submitted with the LRA, is needed.

  - FSAR Item 3.3.1.4.2.3 - In a letter to the NRC dated September 12, 2000, the applicant states that the Heat Exchanger Monitoring Program does not address fouling. The Heat Exchanger Monitoring Program will inspect heat exchangers to the extent required to ensure seismic qualification is maintained, but it is not intended to monitor for fouling. A staff review of the LRA, the applicant's responses to the staff's request for additional information, and the applicable AMPs, verified that fouling will be adequately managed by other programs such as the Service Water Integrity Program or system surveillance testing. The staff finds that no change to Section 16.1.3 of the FSAR Supplemented, as submitted with the LRA, is needed.

- FSAR Item 3.3.1.4.3.3 - After a review of the LRA, the applicant's responses to the staff's request for additional information, and the applicable AMPs, the staff verified that the wall thinning inspection program was not limited to the chilled water components of penetrations 51 and 59. Other reactor building isolation system carbon steel components credit the Wall Thinning Inspection Program. These other penetrations are correctly listed in the program description in Appendix B of the LRA (Section 3.7) and in the FSAR Supplement as submitted with the LRA. The staff finds that no change to Section 16.1.7 of the FSAR Supplement, as submitted with the LRA, is needed.

- FSAR Item 3.3.2.4.3 - In its revised summary description of Section 16.2.7 of the FSAR Supplement, the applicant states that if an inspection program is determined to be necessary for the CRDM nozzle and other vessel closure penetrations, the applicant will analyze and evaluate axial flaws using NUMARC acceptance criteria, and address circumferential flaws with the NRC on a case-by-case basis. The staff finds the revised summary description as submitted by the applicant in a letter to the NRC dated March 14, 2001, acceptable.

- FSAR Item 3.3.3.3 - In its revised summary description of Section 16.2.3.7 of the FSAR Supplement, the applicant includes a one-time inspection to detect cracking and wall thinning of piping and fittings in the sodium hydroxide system in the summary description of the Augmented Inspection program. The staff finds the revised summary description as submitted by the applicant in a letter to the NRC dated March 14, 2001, acceptable.

- FSAR Item 3.3.7.4 - In its revised summary description of Section 16.1.2 of the FSAR Supplement for inaccessible medium-voltage cables exposed to significant moisture and voltage, the applicant states that it will either test for the presence of aging effects or implement a periodic replacement program for these cables. If periodic replacement of medium-voltage underground cables is determined to be the most effective action for this type of cable, ANO-1 will define the frequency for replacement prior to the expiration of the initial 40-year licensing term. The frequency will be based on site-specific and industry operating experience. The staff finds the revised summary description as submitted by the applicant in a letter to the NRC dated March 14, 2001, acceptable.

- FSAR Item 4.3.4 - In its revised summary description of Section 16.3.2 of the FSAR Supplement, the applicant provides a proposed program to address the environmental effects of fatigue that meet the requirements of 10 CFR 54.21(d). The staff finds the revised summary description as submitted by the applicant in a letter to the NRC dated March 14, 2001, acceptable.
- FSAR Item 4.5.5 - In its revised summary description of Sections 16.2.3.6 and 16.3.4 of the FSAR Supplement, the applicant includes an adequate summary description of the prestress monitoring and trending activities, the acceptance criteria, and corrective actions for managing prestress tendons of the ANO-1 containment in the FSAR Supplement consistent with 10 CFR 54.21(d). The staff finds the revised summary description as submitted by the applicant in a letter to the NRC dated March 14, 2001, acceptable.

- FSAR Item 4.7.3 - In its revised summary description of Section 16.3.6 of the FSAR Supplement, the applicant provides a summary description of the monitoring, evaluation activities, optional corrective actions, and decision criteria for the aging of Boraflex in the spent fuel pool. The staff finds the revised summary description as submitted by the applicant in a letter to the NRC dated March 14, 2001, acceptable.

- Open Item 3.3.7.2-1 - Buried (inaccessible) medium-voltage cables, exposed to ground water typically do not have comparable accessible cables exposed to a similar environment that can serve as a sample for these inaccessible cables. For buried cable exposed to ground water that are within the scope of license renewal and subject to an AMR, visual inspection is not sufficient for managing a reduced insulation resistance to ground, and potential electrical failure due to moisture intrusion, water treeing, and contamination so that the intended function will be maintained consistent with the applicant's CLB for the period of extended operation in accordance with the requirements of 10 CFR 54.21(a)(3).

  In response to this concern, the applicant committed to implement either a test or replacement program for the cables of concern. If a testing program is implemented, inaccessible medium-voltage cables exposed to moisture and voltage will be tested for the presence of aging. The specific type of test that will be performed will be identified and implemented prior to entering the period of extended operation. This test will provide an indication of insulation integrity. Along with this test, the applicant will monitor and manage groundwater in manholes containing in-scope medium-voltage cables to reduce the exposure of these cables to moisture.

  The applicant is also considering a periodic replacement program based on industry and site-specific operational experience, as an alternate approach to testing and monitoring. If the applicant determines periodic replacement to be a more effective means of managing the aging of these cables, the program will be implemented prior to entering the period of extended operation. The staff finds this resolution to Open Item 3.3.7.2-1 acceptable.

- Open Item 4.5.2-1 - In response to an NRC staff RAI, the applicant did not adequately describe the AMP for the prestress forces for the ANO-1 containment. Specifically, the applicant needed to provide additional information regarding the prestress monitoring and trending activities, the acceptance criteria, and corrective actions when acceptance criteria are not met.

  In a letter to the NRC dated March 14, 2001, the applicant provided sufficient information regarding the prestress monitoring and trending activities, the acceptance criteria, and corrective actions when acceptance criteria are not met. This information provided by the applicant and the staff's evaluation of this information is discussed in Section 4.5.2 of this SER. The staff finds the additional information regarding prestress tendon forces for the ANO-1 containment acceptable to resolve Open Item 4.5.2-1.

- Open Item 4.7.2-1 - The applicant needed to provide the basis upon which the staff can conclude that there is reasonable assurance that the effects of aging of Boraflex will

be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1).

In a letter to the NRC dated March 14, 2001, the applicant acknowledges the analysis of Boraflex in the spent fuel storage racks as a time limited aging analysis. The applicant further states that the existing analysis is not valid through the license renewal period and cannot be acceptably projected to the end of the license renewal period as documented in a letter to the NRC dated September 6, 2000. In accordance with 10CFR54.21(c)(1)(iii), the applicant committed to continue its boraflex monitoring program to provide reasonable assurance that the effects of aging on the intended function will be adequately managed for the period of extended operation.

In its March 14, 2001 letter, the applicant also provides the additional information regarding the boraflex monitoring program requested by the staff in a letter to the applicant dated May 5, 2000. This information provided by the applicant and the staff's evaluation of this information is discussed in Section 4.7.2 of this SER. The staff finds the additional information regarding the boraflex monitoring program acceptable to resolve Open Item 4.7.2-1.