Official Transcript of Proceedings ACRST-3370

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards

Docket Number: (not applicable)

PROCESS USING ADAMS
TEMPLATE: ACRS/ACNW-005

SUNSI REVIEW COMPLETE

Location: Rockville, Maryland

Date: Wednesday, November 1, 2006

Work Order No.: NRC-1299

Pages 1-245

ORIGINAL

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

TR04

DISCLAIMER

UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

November 1, 2006

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on November 1, 2006, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

This transcript has not been reviewed, corrected and edited and it may contain inaccuracies.

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

+ + + + +

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

537TH MEETING

+ + + + +

WEDNESDAY,

NOVEMBER 1, 2006

+ + + + +

The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 8:30 a.m., Dr. Graham B. Wallis, Chairman, presiding.

MEMBERS PRESENT:

GRAHAM B. WALLIS	Chairman
WILLIAM J. SHACK	Vice Chairman
GEORGE E. APOSTOLAKIS	ACRS Member
J. SAM ARMIJO	ACRS Member
MARIO V. BONACA	ACRS Member
MICHAEL CORRADINI	ACRS Member
THOMAS S. KRESS	ACRS Member
OTTO L. MAYNARD	ACRS Member
DANA A. POWERS	ACRS Member
WILLIAM J. SHACK	ACRS Member
JOHN D. SIEBER	ACRS Member-At-Large

ACRS STAFF PRESENT:

PATRICIA LOUGHEED (Via telephone)

JENNY M. GALLO

MICHAEL R. SNODDERLY

SAM DURAISWAMY

JUAN AYALA

FRANK GILLESPIE

LOUISE LUND

PAT PATNICK

NEIL RAY

BOB RADLINSKI

PHIL QUALLS

SUNIL WEERAKKODY

GARY HAMMER

STEPHEN DINSMORE

MIKE TSCHILTZ

MARK RUBEN

TIM COLLINS

ALSO PRESENT:

BOB VINCENT

BRIAN BROGAN

JOHN KNEELAND

MARK CIMOCK

KEVIN CAMPS

RICHARD DUDLEY

JOHN BUTLER

P R O C E E D I N G S

(8:34:22 a.m.)

CHAIRMAN WALLIS: Good morning. The meeting will now come to order. This is the first day of the 537th Meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the committee will consider the following - final review of the license application for the Palisades Nuclear Plant, proposed revisions to Regulatory Guide 1.189, "Fire Protection for Operating Nuclear Power Plants", draft final rule to risk-inform 10 CRF 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors", proposed revisions to Regulatory Guides and Standard Review Plan Sections in support of new reactor licensing, and the preparation of ACRS reports.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Dr. John Larkins is the Designated Federal Official for the initial portion of the meeting. We have received no written comments from members of the public regarding today's session. We have received requests from Mr. Fred Emerson, BWR Owner's Group, for time to make oral statements regarding 10 CFR 50.46, and Mr. Kevin Camps, Nuclear Information Resource Service, regarding Palisades Nuclear Plant license renewal.

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 have a couple of items of current interest regarding changes in our staff. Maitri Banerjee joined the ACRS Staff on October 2nd. She has a Master of Science degree in Nuclear Engineering from Columbia in the City of New York, Master of Science degree in Physics from the University of Calcutta, India, and a Professional Engineer's license from the State of New Jersey. She has 10 years of experience with NRR, working as Senior Project Manager, Technical Assistant to the Associate Director, Regional Coordinator in the Office of the EDO, and Operating Engineer in the Inspection Program Branch. In these positions, she provided a management and coordination function for NRR review of various licensing actions.

In addition, Maitri worked at Region I for eight years as a Senior Resident Inspector at

Susquehanna, Resident Inspector, Enforcement Coordinator, and State Liaison Officer at Oyster Creek.

Before joining the NRC, Maitri worked 11 years for the nuclear industry supporting plant operation at Indian Point II, Salem, and Hope Creek. Please welcome Maitri.

(Applause.)

CHAIRMAN WALLIS: I'd also like to welcome Carol Brown. Carol Brown joined the ACRS Staff on October 16, 2006 as the Technical Secretary. She will be performing the work previously handled by Sherry Meador. Carol started her career four years ago as a Branch Secretary in the Office of NRR, Division of Engineering. Most recently, she was Division Secretary in the Division of New Reactor Licensing.

Prior to coming to NRC, Carol received her BA in Theater Arts from American University in Washington, D.C., and has performed on stage in the Washington area, so she should be well-prepared for th is job.

(Laughter.)

CHAIRMAN WALLIS: Please welcome Carol.

(Applause.)

CHAIRMAN WALLIS: I'd like to get on with our serious business we have to do today. The first item on the agenda is the final review of the license renewal application for Palisades Nuclear Plant. I turn to Jack Sieber to lead us through this item.

DR. SIEBER: Thank you, Mr. Chairman. Our plant license renewal subcommittee reviewed the Palisades application and the SER on July 11th, 2006, and that was a very good meeting, and a very thorough presentation by the staff and the licensee. And we benefitted greatly from that meeting, and hopefully, from this meeting, also. So I would like to introduce to you a person who has appeared before us many times, Frank Gillespie, and he will introduce the Staff's presenters today, and also the licensee presenters. Frank.

MR. GILLESPIE: Thank you. Actually, my Staff all have their scripts prepared, and so they won't have to change them, I'm going to start with Louise Lund, who has a whole page in front of her. And they're all set up to do the introduction, so I'm going to turn it over to Louise.

MS. LUND: And I'll give the mic back to Frank after I'm done. Good morning. I'm Louise

Lund. I'm the Branch Chief in License Renewal, Branch A in the Division of License Renewal. And with me, of course, is Frank Gillespie, our Director for the Division of License Renewal. And to the other side of Frank is Mr. Juan Ayala, and he was the Project Manager for this review. And he will lead the Staff's presentation this morning. In addition, Patricia Lougheed, who is our Team Leader for the Region III inspections that were conducted at the Palisades Nuclear Plant, is also available. We have also several members of the NRR technical staff here in the audience to provide additional information and answer your questions. We have received a lot of excellent support from the staff in the review, and we certainly appreciate their efforts. We feel the Staff has conducted a detailed and thorough review of this application that was submitted in March of 2005. And I'd also like to acknowledge the efforts of the Palisades staff. They provided excellent support to us through our audits, our inspections, now responses to the request for additional information.

The application was submitted using the draft GALL report that was issued back in January 2005. However, it was reconciled with the September

2005 version of the GALL report. In fact, it resulted in about a 95 percent consistency between their application and the revised GALL.

We issued the initial SER back in June of 2006. There were no open items, and one confirmatory item. And as a result of fairly quick resolution to the confirmatory item, we were able to support having the final meeting this date, so we appreciate all the efforts to get us where we are today.

And with that, I'd like to turn it back over to Frank to see if he has any other opening remarks? No. Okay. So I'd like to turn it over to Bob Vincent, who is the Manager of this project, to begin the Applicant's presentation.

MR. VINCENT: Thank you. I'm Bob Vincent. I'm the License Renewal Project Manager for Palisades, and with me is Paul Harden, the site Vice President at the Palisades site. We appreciate the opportunity to meet with you today, and we're very pleased to be at this stage of our license renewal process.

We have a number of people along with us today that I'll quickly introduce. We have Mark Cimock, who's the Mechanical and Civil Structural

Lead for the project, Larry Seamans, the Electrical Lead, Bill Roberts, the Programs Lead, John Kneeland, the TLAA Lead, and Brian Brogan who's the site PRA and Safety Analysis Lead, and Rich Werdann, who is the Palisades Site Manager of Projects. And then, in addition, we have Gene Eckholdt from the Prairie Island License Renewal Project, who will be following us in a year or two.

So what we'd like to do, briefly, is Paul will initially provide a brief plant description and the current plant status, and then talk about some plant modifications and improvements that we have done over the years. Then I will talk in a little bit more detail about the license renewal project, and two technical issues of interest that we addressed during the project. So without further delay, I'll turn it over to Paul.

DR. SIEBER: Let me interrupt this for a second. During our subcommittee meeting, I noted that Palisades has somewhat of an issue with the embrittlement of the reactor vessel, and I would appreciate it if you would - both you and the staff would elaborate on what the issues are, what you plan to do about it. And, obviously, everything is fine for the normal term of the license, but there's work yet to be done in that area, and so I would like you to spend a little extra time on that.

MR. HARDEN: Absolutely. That's one of the two technical issues that we have in the presentation.

DR. SIEBER: Okay, good.

MR. HARDEN: Okay. Good morning. I'm Paul Harden, the site Vice President of Palisades, and I'd like to begin the presentation with a little bit of background on Palisades, and some of the major modifications that we have completed over the year. The Palisades plant is owned by Consumers Energy Company, and it's operated by the Nuclear Management Company. It's on a 432 acre site in Covert, Michigan, sitting on the shore of Lake Michigan. It's a combustion engineering designed NSSS, and with Bechtel as the architect/engineer. The NSSS itself is two loops, two steam generators, four reactor coolant pumps. The license power level of the plant is 2565.4 megawatts thermal, and the current license expires on March 24th of 2011.

The plant has a pre-stressed concrete containment building. We have forced draft cooling towers. Our ultimate heat sink is Lake Michigan, via the service water system. It's one of the plants where the design was reviewed through the systematic evaluation plan, and our current PRA shows a core damage frequency from internal events of 2.5 E to the minus 5 per year, with large early release frequency of 3.55 E to the minus 7 per year.

Currently, the plant is running well on 100 percent power, in our 19^{th} operating cycle. Today is day 170 of our current production run, and our next scheduled refueling outage is the fall of 2007. Currently, with the third-quarter submittal, all of our performance indicators are green. I will note that is a change from the second-quarter submittal with the implementation of the new MSPI indicator. We did have one white indicator for MSPI on high-pressure injection. That is back to green in the third-quarter submittal. And no current inspection findings that are greater than green.

Some of the major modifications that we've performed at Palisades over the years; in the 1974-75 time frame, the plant was converted from a once-through cooling circulating cooling system to the forced draft cooling towers, and at that point in time, the condenser was retubed. It was originally admiralty tubing, and we went to the copper, nickel 9010 tubing at the time.

In 1983 we added a third auxiliary feedwater pump, upgraded the system to safety grade, and established two independent safety grade trains for auxiliary feedwater. In 1983 we also upgraded the control room HVAC system for the plant to be safety grade. And then in 1989, we performed our first major modification at the site that really came through PRA insight, and that was diversifying our connection to off-site power feeds with a dedicated underground power feed to the safety-related buses.

DR. APOSTOLAKIS: Why did you do this? The core damage frequency was high or what?

MR. HARDEN: It was PRA insight to reduce core damage frequency at the time. And, actually, there are other modifications that I'll discuss as we go along, that through the years where we gained additional insight through PRA, we have also implemented other modifications to reduce core damage frequency.

DR. APOSTOLAKIS: I'm curious, was the core damage frequency too high, and how high is too high?

MR. HARDEN: I don't know. Brian Brogan might be able to answer where it was at the time before and after we performed that modification. Brian.

MR. BROGAN: Brian Brogan from Palisades. At the time we did the mod, it was about 5 to 6 E to the minus 5. The mod was driven by our insights gained from reviewing how fast transfer was operating, some of the problems we were having with fast transfer. And by going through this specific mod and creating a dedicated safeguards bus, we eliminated several of those demand requirements that we were imposing on our system.

DR. APOSTOLAKIS: But it -- so it wasn't really the absolute value of the CDF that drove the decisions. Right?

MR. BROGAN: It was the process in doing the EPSA. Obviously, developing insights, seeing what the qualitative results were, strongly suggesting that we would improve our plant reliability if we would go through with this mod.

DR. APOSTOLAKIS: Thank you.

MR. HARDEN: Okay. In 1990, we replaced the steam generators at Palisades. And at that time, we retubed the condenser and the feedwater heaters, again. At that point in time, with the replacement steam generators. The reason the condenser was retubed again was to remove all the copper from the system. We went to the 439 stainless steel tubing.

In 1983, we first implemented dry fuel storage.

DR. SHACK: Your tubing material then in 1990 is alloy 600 TT?

MR. HARDEN: The steam generator tubing? Yes, the replacement steam generators were the mill annealed Alloy 600 tubing, because these steam generators, the replacement, the fabrication was actually started in the late '70s, early 80's time frame due to startup issues from the original licensing startup of Palisades.

DR. SHACK: So this is a classic CE high temperature mill annealed 600?

MR. HARDEN: Yes. There were some changes incorporated from the original steam generators just due to technology at the time, but this was the early 80's technology, before the industry had shifted away from the Alloy 600 mill annealed.

In 1995, through PRA insight, we implemented another modification. This was to modify our under reactor vessel floor drains to the containment sump. And this modification was one that really provides protection from a severe core damage-type event from core debris that could otherwise flow to the sump.

In 2003, we implemented our risk-informed in-service inspection program, and that was a full scope risk-informed program that we implemented. And then recently in 2006, we performed another modification from PRA insight that came out of our SAMA reviews, and that was to install a third non-safety-related supplemental emergency diesel generator to the site that has the capability to supply power to either electrical train at the site. And with that, I'll --

DR. APOSTOLAKIS: How often do you update your PRA? Is it a living PRA, a sick PRA, dead PRA? What is it?

MR. BROGAN: Brian Brogan from Palisades. Our schedule calls for major updates to be completed on a two-year frequency. However, we've been updating on the average of three times over the last year and a half, so we've --

DR. APOSTOLAKIS: Why was that?

MR. BROGAN: Well, for a variety of reasons. We wanted to add additional rigor to the model to address MSPI issues that we had to monitor. These issues were not important in terms of safety; however, to meet the requirements of the program, we had to add additional logic to the model, just to be able to monitor the components.

DR. APOSTOLAKIS: What does an update entail? I mean, obviously, the plant configuration and the new mods that you have implemented. Do you also look at the statistical records of failures, possible failures, and so on?

MR. BROGAN: Yes. For example, during the update in support of the supplemental diesel, we went and re-evaluated, re-baselined our diesel reliability numbers. Updates also include looking at procedures again, to make sure that any change to the EOPs, MOPs, alarm response procedures, et cetera, are properly accounted for in the model. So it's data, it's procedures, it's plant physical mods, it's also any new insights that have been identified. We want to make sure that we capture them all.

DR. APOSTOLAKIS: And all this is done in-house?

MR. BROGAN: Yes.

DR. APOSTOLAKIS: And you only have the

internal event at power PRA. Do you have any plans to do anything else, like external events, or maybe low power shutdown?

MR. BROGAN: Regarding external events, we have updated our internal flooding model. We did that in '05. We're in the process of transitioning to an MPA 805. That's scheduled for completion in the end of 2008.

DR. APOSTOLAKIS: So you will have a fire risk assessment then?

MR. BROGAN: Yes, we will have a fire risk assessment, and update from the IPEEE that was submitted in '95. And, also, we have plans to update our seismic response model, as well.

DR. APOSTOLAKIS: Low power shutdown?

MR. BROGAN: Right now, we are not going to pursue a numerical low power shutdown model. We're going to continue with our present NEI qualitative shutdown risk model.

DR. BONACA: How many people do you have working in the PRA group?

MR. BROGAN: Two.

DR. APOSTOLAKIS: Do you have external help, as well?

MR. BROGAN: Excuse me?

DR. APOSTOLAKIS: Do you have contractors that help you with the PRAs?

MR. BROGAN: Yes, we do. Yes, we do. We have a wide variety of folks that check our work, help us out, and that's how we manage to get this work done with just two folks on site.

DR. BONACA: Because every update of the PRA will take you many years of manpower.

MR. BROGAN: That's correct.

DR. APOSTOLAKIS: In fact, I'm curious. What is the effort that's required to update?

MR. BROGAN: It can be fairly extensive. For example, updating the LERF calculation requires quantification of 50 million sequences theoretically, so there's a lot of --

DR. APOSTOLAKIS: You don't do it by hand, I hope.

MR. BROGAN: No, we don't do it by hand, of course. But that requires, you know, the typical bookkeeping that you have to do to bin properly those sequences. And then, of course, just the machinations, anyway, to redo the numbers.

DR. APOSTOLAKIS: Actually, how much effort does it take?

MR. BROGAN: It takes, for a specific

update, I would say three to four man-weeks, at least. And that does not include outside technical review. For example, in reviews that -- any work that I do with a map code, for example, I contract out to the fellows that wrote the code to watch my back. The same with data. And being an old person, we have a lot of contacts in the industry that have been doing this for a lot of years, so we have a variety of folks that watch what we do.

DR. APOSTOLAKIS: And, last question, which computer code do you use for your PRA?

MR. BROGAN: Well, we use several. We use SAPPHIRE, we use SETS, we use CAFTA. We also use the Top Event Prevention Program that you may be familiar with.

DR. APOSTOLAKIS: I am very familiar with it. But the basic PRA model is in SAPPHIRE?

MR. BROGAN: SAPPHIRE and CAFTA at this time, yes. And we use SETS for checking, we use Top Event Prevention for checking, as well.

DR. APOSTOLAKIS: Good. Thank you very much.

DR. MAYNARD: I would assume that although you have just two people on site, you also have the resources of NMC and the other plants if you needed assistance.

MR. BROGAN: That's correct.

MR. HARDEN: Yes. We have fleet resources, and also Brian mentioned outside contract resources we use. They're long-established relationships with the outside resources that we use, so they're very familiar with our models, and very familiar with the Palisades plant, as well as we also continue across the whole site, as many in the industry do with demographic studies - like we have plans to train a third person in the PRA area at Palisades to continue to ensure that we maintain the --

MR. BROGAN: Palisades began developing its PMC expertise back in 1982, well before the IPEEE Generic Letter 88.20 was released, and that was a specific application that was put in place to address an SEP issue. So a lot of the folks that were part of the Big Rock Risk Assessment Team, both contractors and plant personnel, then made the trip down to Palisades and began that body of work in '82, so the infrastructure was laid in '82, '83, '84 during the submittal of the MSIV SEP body of work to the NRC.

DR. APOSTOLAKIS: I really find it very

interesting that you have implemented modifications even though your CDF and LERF did meet the regulatory goals.

MR. HARDEN: If I could add, like on the most recent modification, and Brian would have to give the exact numbers, but with this supplemental emergency diesel generator, it almost cut in half our overall core damage frequency. It was less than half.

DR. APOSTOLAKIS: But that was low to begin with. That's what impresses me.

MR. HARDEN: From managing risk of the plant, which is where we've taken the industry, we use the PRA models in a lot of the SAMA efforts to help us make decisions that we play into cost-benefit modifications.

DR. APOSTOLAKIS: That's good.

DR. SIEBER: I guess I would point out that that's not unusual. A lot of plants make modifications to improve their risk roster.

DR. BONACA: Especially if you have specific insights on sequences, or modifications, because you may have an outlier there, and you may have -- that is significant.

DR. APOSTOLAKIS: Well, the thing is

that if you are already below the goal, you're actually doing cost-benefit kind of evaluation, at least in your mind, maybe on paper, too.

CHAIRMAN WALLIS: It's more than that, George. I mean, it's not just meeting the regulations. They don't want to have a core damage accident either.

DR. APOSTOLAKIS: Yes.

DR. BONACA: I'm only pointing out, it's only internal events. I mean, typically an older plant like this --

DR. APOSTOLAKIS: This is an ideal world I'm presenting -- we're being presented with.

DR. SIEBER: It's important. My grandchildren live pretty close to this plant.

DR. APOSTOLAKIS: Everybody's a saint.

CHAIRMAN WALLIS: The world isn't so bad, George.

DR. SIEBER: Okay. Let's move on.

MR. HARDEN: At this point, I'll turn it over to Bob Vincent to discuss a little bit about the license renewal project itself.

MR. VINCENT: Thanks, Paul. Palisades designed its license renewal project right at the beginning as a site project. We staffed it with highly experienced, highly plant experienced leads for the technical disciplines, and then we supplemented that with license renewal experienced contract support. We kept the plant very closely involved in program development and so on, so this - what you see truly represents a plant effort, and it's not an effort that we will simply walk away from at the end of the project.

The application, as Louise mentioned, was prepared using an earlier version of the GALL. We actually based it initially on GALL Revision 0, and then we did update our GALL reconciliation, our comparison after Revision 1 of the GALL was issued in 2005. And that substantially increased our consistency with GALL. The Gall Rev.1 is clearly a valuable product for the industry.

The outcome of all this is that we will manage aging in the future with 24 programs, four are new programs, 20 are existing programs. The descriptions of those programs, TLAA descriptions and commitments will be incorporated into the FSAR, and then one other difference from some plants is that the project team continues to exist today, and will continue through next year, even after we hope the license is issued to work on implementation. By the end of 2007, we should have the complete infrastructure for implementing all the new requirements and commitments that have come out, that will come along with the renewed license.

The infrastructure will be in place, procedures in places, and we should be in good shape to implement our future requirements consistent with all of the discussions, and all the things we have learned over the last couple of years during NRC reviews.

DR. ARMIJO: Excuse me, just a second.

MR. VINCENT: Yes.

DR. ARMIJO: In going through your list of commitments, I notice that there were several that had a completion date of October 31, 2005.

MR. VINCENT: Yes.

DR. ARMIJO: Those have already been completed, or is that a typo across the board, or what? It's confusing. It's worded that NMC will submit for NRC review, et cetera, by October 31, 2005.

That means it's already done?

MR. VINCENT: Yes, they are already done.

DR. ARMIJO: Good.

MR. VINCENT: Of the 55 commitments, 10

were short-term commitments we made to support the NRC reviews, where we were missing information, we could not fully answer an RAI, something like that. We would try to make a commitment to complete the work on a schedule that would support the staff's reviews, so the last 10 commitments listed in the SER are, in fact, complete.

DR. ARMIJO: Thank you.

MR. VINCENT: All right. The first technical issue I'd like to touch on was the issue that the confirmatory item was based on, intergranular separation or under-clad cracking. In the 1970's, this was a generic industry question, and it was dispositioned in the 70's as an issue that did not negatively effect reactor vessel integrity for the 40-year life times of those plants.

When license renewal emerged, Westinghouse developed an evaluation for the entire Westinghouse fleet that justified this condition was acceptable through the 60-year operating life times. That Westinghouse evaluation covered all the vessels in the fleet, which included those manufactured by Combustion Engineering, B&W, and outside the United States. The NRC did review and accept the methodology, and the results of those evaluations.

Palisades was not addressed in that original Westinghouse report. We were not part of the Westinghouse fleet at that point, so we had Westinghouse go back and apply the same methodology, using Palisades-specific information, and Westinghouse documented that in an additional -- in a Palisades-specific report. The results are, as you would expect, fully consistent with the WCAP-15338 for the Westinghouse fleet, which means any potential under-clad cracking or intergranular separation that does exist would show little or no growth over 60 years, and would have no effect on the structural integrity of the reactor vessel.

DR. SIEBER: Who's the manufacturer of your vessel?

MR. VINCENT: Combustion Engineering.

DR. SIEBER: Okay.

MR. VINCENT: We submitted that, of course, to the NRC. The NRC reviewed it, and as the SER reflects, the NRC has closed that confirmatory item. The other issue I'd like to touch on, and that gets back to Mr. Sieber's question - pressurized thermal shock. Palisades projects that we will reach the 10 CFR 50.61 screening criteria in

2014. Starting in the late 80's/early 90's, and through the 90's, we have implemented a very aggressive flux reduction program in what we call our ultra low-leakage core design, that actually involves having shielding bundles in select locations in the core, et cetera.

DR. BONACA: But that will not push you beyond --

MR. VINCENT: I'm sorry?

DR. BONACA: That would not push you beyond 2014. Right? I mean, you're already creating that, to get to 2014.

DR. SIEBER: That's how they get that far.

MR. VINCENT: That's how we get to 2014. As many of you, I think, are aware, we have been one of the plants participating in the NRC's research program to develop a new technical methodology for dealing with PTS.

We do have a number of alternatives available to manage the issue for the period of extended operation. If the research program and the rule making results in a change to 10 CFR 50.61, that may preclude the need for plant-specific management strategy for PTS. The rule making, as, again, I'm sure you're aware, has a draft rule issued by April of next year, and a final draft rule issued in February of 2008.

DR. SIEBER: Yes, don't put all your money on that one.

MR. VINCENT: Absolutely not.

DR. SIEBER: Don't put any money on that.

MR. VINCENT: No, but that's my point here. We do have a number of alternatives available. And if you would like, we do have a backup slide in here that lists the major alternatives. If you'd like me to touch on that specifically, I can right now.

DR. SIEBER: Well, you aren't going to be -- you aren't prepared to tell us what decision you will make.

MR. VINCENT: No.

DR. SIEBER: And the alternatives are well-known, they're part of the rule.

MR. VINCENT: Right.

DR. SIEBER: They will probably be part of my report on your plant.

MR. VINCENT: Okay.

DR. SIEBER: And unless somebody has a great need to know what they can do, like annealing and so forth.

DR. ARMIJO: Just a real quick listing, you don't have to go into the details, but what are your options?

MR. VINCENT: Okay. If you'd look at backup slide 11 in your handout package, and I'll just quick jump to that.

DR. SHACK: Page 16 in your package.

MR. VINCENT: Oh, I got it. There it is. I'm sorry. Basically, one of the options right now is to request an exemption using master curve technology for determining fracture toughness, to justify continued use of the vessel through the 60-year operating period.

10 CFR 50.61, bullet 3 on this list, addresses a safety analysis, and Reg Guide 1.154 provides some guidance on how to do a safety analysis. The purpose of that analysis is to evaluate actions that could be implemented, operational changes, et cetera, that would assure vessel integrity during a PTS event if continued operation is permitted beyond the acceptance criteria in the rule.

One example that we've tossed out is heating of safety injection water, which could certainly reduce the thermal stresses in the vessel wall during a PTS event. So that's some kind of an analysis, and I would just mention that the output from the NRC's research program, NUREG-1806, could possibly be a part of our safety analysis.

Annealing is certainly an option under 10 CFR 50.66. Further flux reduction, the question arose about it. What we have in place right now is a pretty aggressive core design. It would be very difficult to get sufficient flux reduction to allow us to run using this approach alone through 2031.

DR. SIEBER: You could actually use neutron absorbing curtain rods, but the amount of assemblies you would have to change out at each refueling would drive your fuel cost very high.

MR. HARDEN: Would drive fuel costs, and it also starts to drive power peaking in the summer.

DR. SIEBER: Yes, you might not be able to get 100 percent power.

MR. VINCENT: So those are some of the major things that we considered.

DR. ARMIJO: Thank you.

DR. SIEBER: Annealing has never been done any place. Is that correct? The Russians tried it.

DR. SHACK: They do it regularly.

DR. SIEBER: Yes, but I don't know very

much about what their outcomes have been. How do you test it once you anneal it? But it hasn't been done in this country.

MR. VINCENT: Not on an operational vessel, no.

DR. SIEBER: And it's not easy to do.

MR. VINCENT: Not easy to do.

MR. HARDEN: Consumers Energy, the owner of Palisades, in the 90's did invest considerable resources in researching that option, and what it would take if that becomes --

DR. SIEBER: You have a neutron shield tank there, so the -- you have a lot of equipment to take apart, get to the vessel.

MR. VINCENT: It would --

DR. SIEBER: It's not an easy solution.

MR. VINCENT: No, it would be a very complex project.

DR. BONACA: Is your PTS scenario, the limiting scenario, is it steam line break, or is it LOCA?

MR. VINCENT: Brian, would you care to address that? The limiting scenario for a PTS kind of event.

MR. BROGAN: The limiting scenario is

still a LOCA.

DR. SHACK: In the under-clad cracking, has anybody done an inspection after X years of operation, or is this all basically analysis from the Westinghouse Topical Report?

MR. VINCENT: This is really analysis in the Bechtel Palisades-specific report.

DR. SHACK: But no plant anywhere has done an inspection.

MR. VINCENT: In the very early days, I understand there were some structure tests.

DR. SHACK: But those are the ones to verify that there was such a thing as under-clad cracking. Now you analyze the growth -- I just wondered if anybody had looked at it after 25 or 30 years?

MR. VINCENT: I'm not aware of an in-service inspection-type examination.

DR. SHACK: Can you even see this with any kind of in-service --

DR. SIEBER: I would doubt it.

MR. HARDEN: Your question was, can you even see it? I'm not sure with the technology available if you would.

DR. ARMIJO: To that point, is anybody

working on advanced NDT techniques, like phased array techniques to measure those, or detect them?

MR. VINCENT: Not that we're aware of. But since these separations were evaluated a number of times and determined not to effect the vessel integrity, I think that kind of an effort would be a research program, as opposed to developing an in-service inspection technique that would be applied to operational planning, so -- the evaluation just says they're not going to grow, and there's not any confirmation that they aren't growing.

MR. HARDEN: I think John, and you can speak up, John Kneeland may have some work, but there are some things that can be seen when you do your reactor vessel in-service inspection. I don't know, John, if you want to provide any more information on that.

MR. KNEELAND: All right. This is John Kneeland. Back in 1983 at Palisades, during the ISI, they discovered some reheat cracking near one of the welds, and it's much smaller than you'd typically have to report, but they did see some indications, identified as reheat cracking. And we did look at those again in our 1995 ISI, and there was no indication of any growth. All the indications were identical with what we saw in 1983.

DR. ARMIJO: That was the same phenomenon?

MR. KNEELAND: Yes.

MR. VINCENT: That concludes our presentation. If there are some additional questions, we'd be happy to address those.

DR. BONACA: Just a question on your small-bore piping inspections, page 15. You're inspecting also a population in susceptible locations. Right? Irrespective of risk-informed, or your one-time inspection, could you tell me what's the basis for it?

MR. VINCENT: This slide shows Palisades, as we mentioned, has a risk-informed ISI program. And as part of that program, we do a volumetric examination of a sample of Class 1 butt weld small-bore, and each cycle, each refueling cycle, we do a 100 percent examination using VT-2 of socket welds, of all high-safety-significant socket welds. And we do that inspection of Class 1, Class 2, Class 3 or non-ASME classed socket welds, just every high-safety-significant weld.

DR. BONACA: Every weld.

MR. VINCENT: For license renewal, and I list the population here of welds that we have for

Class 1. For license renewal, our specific commitment is to continue that 100 percent VT-2 of socket weld examinations each cycle. And then, in addition, we will do a 10 percent examination of Class 1 butt welds as a one-time inspection between now and the end of our current --

DR. BONACA: My question was how will you select the 10 percent? Will you look for susceptible locations, or will you just --

MR. HARDEN: Mark Cimock may be able to provide a little more information on exactly how the 10 percent is determined.

MR. CIMOCK: This is Mark Cimock. Yes, we do look for high susceptible locations. Part of the risk-informed program was to look at what could cause failures, and then identify the appropriate inspection technique to look for that type of failure, and then to look at the most susceptible locations.

DR. BONACA: Okay. Thank you.

DR. SIEBER: What do you know about how -- what techniques were used when welders welded the small-bore piping and socket welds? For example, if you take a socket weld and you put the pipe flat into the socket weld, and then weld it, and then heat up the plant, it's going to crack.

MR. VINCENT: Certainly.

DR. SIEBER: You have to withdraw it somewhat, and some folks did that, and some others did not, and which is the case in your plant? You should know that because --

MR. VINCENT: Yes.

DR. SIEBER: -- you will find a lot of cracks in your UT examination if they didn't do it right.

MR. VINCENT: That's correct.

MR. CIMOCK: This is Mark Cimock, again. The answer is yes, we did do the -- you bottom out and you draw back a 16^{th} inch, and that's actually a code requirement so everybody should be doing that. But that, and the fact that our processes require an independent verification of that, as well, gives us the confidence that has occurred. And the history that we've had with the socket welds since initial plant construction, we've got 35 years of operating history with no real significant socket weld issues.

DR. SIEBER: Well, there is -- it turns out that you're doing a pretty good population of weld examinations there, but it turns out that that's a pretty vulnerable place. And so I think that you should be doing a lot of examinations, as you have committed to do.

MR. HARDEN: And that's one of the reasons why even before license renewal and the commitment, we have been doing like the 100 percent VT walkdowns during every refueling outage.

DR. SIEBER: Have you ever had a failure, a leak?

MR. HARDEN: Mark, can you speak to any specifics on whether we've had leaks on socket welds?

MR. CIMOCK: Yes, we have had some, but it's not -- I wouldn't characterize it as repeat problem at a specific location. We've had a few leaks. Paul is probably familiar, on some of our non-class hydrogen piping around the generator. I think we had one a while back on coolant pump leak-off. But, again, it's not been a recurrent problem. They've been one here, one there. We've addressed them as they have arisen. It's nothing that's --

MR. HARDEN: The only two that come to mind for me in my experience at Palisades, and I've been there 17 years, were two locations that were subjected to high-cycle vibration, or high frequency vibration.

DR. SIEBER: That's the other reason why you end up with small-bore leaks, is fatigue. And I presume your corrective action after you had the first of those was to look at all the supports on branch lines that support instrumentation, or drains, or vents, to make sure everything is properly supported. If you take a small pipe and put a heavy valve at the end, and then shake the device, it is going to fail, and it'll fail right at that weld.

MR. HARDEN: Certainly. Absolutely. And that experience has been applied. One good example, Mark mentioned one example on the primary coolant pump bleed-off line, we've done extensive redesign of most of those small-bore lines for that reason, to eliminate the vibration and the --

DR. SIEBER: You have to do it with the plant hot, and you have to actually go in and look at it, so it's radiation exposure, and you've got to know what you're looking for.

MR. HARDEN: In some of these cases, we've actually gone in and measured the amplitude of the vibration in the lines to determine is it near resonant frequencies and things of that nature to ensure that we've addressed the issue going forward.

DR. SIEBER: You can actually calculate that. There is a standard configuration that will give you a natural frequency that's similar to that which the whole plant is experiencing as pumps are running and so forth. It sounds to me like, from your description, that you actually have done the work, because it's not easy to do. And I think it's important work. Thank you.

MR. VINCENT: Any other questions? Thank you.

DR. SIEBER: Thank you very much.

MR. AYALA: Okay. Good morning. My name is Juan Ayala, and I'm the Project Manager for the Staff's review of the Palisades license renewal application. With me today I have Robert Hsu in the audience, he's the team leader, and he can address any issues or any questions regarding the audits. Ms. Patricia Lougheed, our Regional Inspector, as Louise mentioned, is also available to answer any questions from the inspection. And supporting all of us are all the technical reviewers in the audience for any question that I cannot address for you.

At this moment, I'd like to start off with the list of topics that I'll be covering today. I'm going to be talking, giving a little overview of the plant, and the application, followed by highlights of the review. I'll then finish off with talking about some of the time-limited aging analysis, including the resolution to the confirmatory item, followed by the Staff's conclusion.

As mentioned earlier, the license renewal application was submitted to us March 22nd, 2005. Palisades is located five miles south of South Haven, Michigan, and is a Combustion Engineering PWR with a DRYAMP containment. The plant is at 2,565 megawatt thermal, with a net output electric of 820 megawatts. The operating license, DRP-20, expires March 24th, 2011.

The initial SER was issued on June 1st, 2006 with no open items, and one confirmatory item, which I will cover in detail in a couple of slides. We issued 174 RAIs, and our audits included 412 questions, documented questions. As mentioned earlier, the application is about 95 percent consistent with GALL Revision 1, and our final safety evaluation report was issued September 28th, 2006, with 55 commitments, and three license conditions, and I'll cover those in the next slide.

The three license conditions that

Palisades will have complied to are the same license conditions that have applied to every plant before them. You're very familiar with these, I'm not going to go into great detail, unless you have any questions on any of them.

DR. SIEBER: Those are the same that everybody gets.

MR. AYALA: Yes, the same license conditions that everybody, every PWR has come before us. In this slide right here, it shows the dates of the audits, and our inspections. I'm not going to go into great detail, you can see the dates up there. If you have any questions, I can address those, too.

Okay. To start off the Staff's review highlights, the Staff concluded that the scoping methodology meets the requirements of the regulation. And we also feel that scoping and screening results, as amended, include all the systems, structures, and components that are within the scope of license renewal, and are subject to an aging management review.

There is a list here of some of the items that were brought into scope, and are subject to aging management. If you have any specific questions on any of these, I can go into detail. These are the same list that I provided at the subcommittee. If not, I can just move forward to the next slide. Okay.

CHAIRMAN WALLIS: Why do you put in these pump filters? And I thought these are things which are renewable, and inspected, and so on, and not usually a part of license renewal, are they?

MR. AYALA: They were brought into scope. They weren't in the drawings that they provided, but there was no description in the application, so we considered those as being brought into the scope of license renewal, even though they are replaced. They provided through an RAI response a description in the application, and provided the information on a table, so we added those as brought into scope. So not every item here on this list was something that they were completely missing as some of the components were in scope in their drawings, but they didn't have a system description. Okay?

DR. SIEBER: When you list solenoid valves, they're active components. Right?

MR. AYALA: Yes, they are screened out --

DR. SIEBER: And they're in scope.

MR. AYALA: They're screened out for NEI

95.10, but the valve casings are in scope of license renewal.

DR. SIEBER: That is just a pressure boundary?

MR. AYALA: Yes, pressure boundary.

DR. BONACA: Again, on the boric acid filters, are they subjected to periodic replacement?

MR. AYALA: I believe they are.

DR. BONACA: But why would they be in scope of license renewal?

MR. AYALA: Like I mentioned earlier, they were in their drawings that they provided.

DR. BONACA: I understand.

MR. AYALA: And the Applicant said that they were in scope. I see that Mark Cimock from the licensee is up there, and he wants to answer this question for us.

MR. CIMOCK: This is Mark Cimock. It's a similar situation as the solenoid valves. It's not the filter elements themselves that were in scope, it was the pressure boundary of the body, pressure boundary and structural considerations.

DR. BONACA: Okay.

MR. AYALA: Okay. I'm moving on to the next slide. For inaccessible concrete, the

Applicant stated, and the Staff verified, that below grade environment is non-aggressive. There will be periodic testing of ground water performed as part of the system, the structures monitoring program, at least every five years. The Staff found that the Applicant has appropriately addressed the aging effects and mechanisms, as recommended by GALL. As shown on this table, the test results are well within the acceptable criteria, and no adverse trends exist.

CHAIRMAN WALLIS: There's a trend in chloride.

DR. POWERS: And if I extrapolate the trend, it's bad. I could plot the numbers and --

MR. AYALA: Well, the numbers we have here are still well below the acceptable criteria, so the Staff feels that the numbers are still well below the criteria.

DR. POWERS: Did the Staff plot them versus time?

DR. ARMIJO: If you believe those numbers, it's gone up a factor of five in eight years. Is there a reason for that?

MR. AYALA: I guess for this right here, the Applicant performed the testing in 2004, and these are the numbers that they provided to us. I don't know if any recent testing has been done to prove whether these numbers are -- have maintained, or --

DR. POWERS: That's not the question. The question is, did you plot them versus time?

MR. AYALA: I don't believe we did.

DR. POWERS: Then how do you conclude that everything is okay?

MR. AYALA: We have Bob Vincent from the Applicant. He wants to address the issue.

MR. VINCENT: This is Bob Vincent, again. I would not look at these numbers as showing a trend that you can --

DR. POWERS: Apparently not, but it's apparent that there is a trend.

MR. VINCENT: Well, what we see around the site is a fair amount of variability depending on where you sample.

DR. POWERS: Your numbers don't reflect the variability.

CHAIRMAN WALLIS: Do you salt the roads?

MR. VINCENT: We have heavily, although the chloride number in 2004 was not -- we don't use sodium chloride on the site any more. We may have in the very early days, but this was not a wintertime sample, either. I can't really explain why 139 was what it was, but as Juan said, it's well below any limit of concern. We will be monitoring this over time, and in the future, we'll be able to have enough data on a regular basis, that we will be able to look for trends.

DR. SHACK: What's the period of this periodic testing?

MR. VINCENT: Every five years.

DR. POWERS: Well, if I take the period of eight years there, it suggests you're going to be over 700 next eight years.

MR. VINCENT: I can't argue with that. Certainly, if you look at those two data points as being solid data locked in time following the same trend in the future.

DR. ARMIJO: How else are we supposed to look at them? I mean, I don't know - this is, to me, more of an economic problem that you guys should be worried about. That's an unhealthy trend if you believe the numbers, and if you don't believe the numbers, why are we even looking at it? So I think somebody should pay attention to that, and figure out what is going on. Are the measurements in error, or is it really a trend? Are you doing something that's going to cause you grief in the long-term?

CHAIRMAN WALLIS: Of course, the span in 1966 is a factor of 10, from 4 to 39, so it looks as if you might need to do more statistical sampling. The range seems to be so big, the measurement in '66. Maybe it depends where you sample or something? Anyway, the message that the Staff is going to pay more attention to this, and also, the licensee is going to pay more attention to this.

MR. VINCENT: That's correct.

DR. POWERS: Some attention.

MR. AYALA: Well, as part of the structural monitoring program --

DR. POWERS: I mean, this is kind of unbelievable to sit there and give those numbers and say we see no trend.

DR. ARMIJO: Or say the reason there is no trend is because, and explain it.

MR. HARDEN: This is Paul Harden. I can address it a little bit. You're absolutely right, in the past there was not a lot of attention paid to this from an aging management perspective until we started working on license renewal. The sample in

2004 was something we specifically went out and did to get a current sample, because we had not been doing a frequent regular-basis monitoring to have a statistical trend or statistical analysis of samples going forward.

With our aging management programs going forward, we put in place a sampling frequency of five years to allow us to identify, if that trend continues, we may even choose that we need to do more frequent sampling, more variability of sampling at different locations, things of the nature, but it's something that, because there wasn't a regular sampling and trending done in the past, we don't have the ability today to have a good statistical analysis of that. But going forward with a regular periodicity of sampling, we will have that, and we will have the ability to have much better monitoring than we've had in the past.

CHAIRMAN WALLIS: The risk is you don't do anything for five years, and then you take a sample and find it's 700. And then what happens?

DR. SIEBER: Your concrete degrades.

MR. HARDEN: If we were to take a sample in five years and it was much higher, then we would have many more economic considerations we would have to factor into our aging management of the facility going forward.

CHAIRMAN WALLIS: It might be prudent to take a sample more frequently, in maybe more locations. It's not all that expensive to do.

MR. HARDEN: Yes. Something that's an unrelated effort to the sampling here is, currently there are few wells on the site to take the samples from due to other industry initiatives. We are looking at putting additional wells on site which would actually also give us additional ability to have more locations and more sampling. That's all part of an unrelated effort for the additional wells, but it is going to give us the ability in the future to expand the breadth of what we're able to do from what we can do today.

CHAIRMAN WALLIS: If you said here you will do it, then everyone will be happy.

MR. HARDEN: Well, we are installing additional wells, and we are going to do additional sampling from the actual commitment on the license renewal, and the program there was for every five years. Due to recent industry concerns with tritium, we're actually installing several additional wells on site to allow us to do much more frequent sampling, to do analysis that will include chemical analysis, but that's being done - like I said, it's being driven, primarily, from other factors.

CHAIRMAN WALLIS: Now you've got the message, you will probably also measure chloride.

MR. HARDEN: Absolutely.

DR. SIEBER: I take it the water table is pretty close to the surface there.

MR. HARDEN: Yes, the water table is very high at Palisades, due to the proximity to Lake Michigan.

DR. SIEBER: Yes.

MR. AYALA: Okay.

DR. SIEBER: And if you have chloride in the ground water, I think that it's - you could worry about the concrete, but what you really ought to worry about is all the stainless steel in the plant which will crack if you get a lot of salt on it. That's why most licensees don't salt their roads, they plow them.

MR. HARDEN: Yes.

MR. AYALA: If we can move on to the next slide. For small-bore piping and welds, you saw the presentation that the Applicant had. They will be performing a one-time volumetric examination of 10 percent of Class 1 butt welds, and they will be performed during every outage, 100 percent VT-2 examinations for all Class 1 and Class 2 high-safety-significant socket welds. This will be performed within the last five years of the current operating period, and the Staff found this to be an acceptable commitment that the Applicant provided.

DR. POWERS: Why did the Staff think that 10 percent is a satisfactory fraction?

MR. PATNICK: I'm Pat Patnick from Division of Component Integrity. Ten percent of high-safety-significant weld has been acceptable in the risk-informed ISI program.

DR. POWERS: That doesn't exactly answer why. I mean, all you said it you accepted 10 percent because we accepted 10 percent. I mean, give me a reason on why 10 percent is adequate.

MR. PATNICK: Well, the 10 percent has been based on the core damage frequency to be within the --

DR. POWERS: Now relating 10 percent to core damage frequency strikes me as a real stretch. I would like to see that analysis.

DR. BONACA: Plus, I think it is

inaccurate. What I'm trying to say is that, because the 10 percent is a one-time inspection, which is done in susceptible locations. We discussed that before. It has nothing to do with the 100 percent examination of high-safety-significant sockets, which is PRA-based. Okay? And I think that's important because every time I see this issue about susceptibility, that's why you're making a one-time inspection, because you're not looking normally at susceptible location. And here you want to look for those.

MR. CIMOCK: This is Mark Cimock, again. If I could maybe try to add to that. That's basically the situation. The risk-informed program actually, from a risk-base, had less than 10 percent. They came up with a program that was actually found to be less risky than the current ASME program, so that's part of it. We increased it to 10 percent for license renewal, largely because there's been a precedent in license renewal arena of 10 percent. Now I can't speak to the basis for that, but there was past applicants that had used the 10 percent, so we decided rather than just using the lower than 10 percent that we have based on risk, we bumped it up to 10 percent to be consistent with the industry.

MR. AYALA: Any other questions here? Okay.

CHAIRMAN WALLIS: Are there any probabilistic analysis; if you do the sampling of 10 percent on a certain frequency, then what's the probability of a bad weld not being observed? Do you do anything like that?

MR. CIMOCK: I'm sorry, could you repeat the question, again?

CHAIRMAN WALLIS: If I were worried about a weld being bad, then I would probably want to make some assessment of its probability, and how well I needed to sample in order to get some assurance that if it were bad, I would find it. That seems to me the basis for sampling. Did you do anything like that? I'm just asking.

MR. CIMOCK: What we actually did as part of the risk-informed program was we tried, as was mentioned, we tried to identify the most susceptible locations with the most susceptible mechanism, and use the appropriate investigation. So even though it's a 10 percent sample, we think we're going after the potentially worst actors, and we have a higher confidence that if there's problems, we're looking at the right places to try to find those problems.

DR. ARMIJO: What criteria did you use to pick your most susceptible or highest risk welds so that you could get a reliable sample that you're looking at the worst case?

MR. CIMOCK: Again, this is Mark Cimock. We used a combination of items. We used plant-specific OE, we used industry OE. We used kind of what I call a mini expert panel of people with ISI experience that have been at the plant a number of years, combined with design engineering expertise, and risk expertise. They used a lot of plant-specific knowledge, and OE design knowledge and stuff to try to identify what our past history has told us, what the industry history has told us, and what our plant experience is telling us.

DR. ARMIJO: Thank you.

MR. AYALA: Okay. Moving on with --

CHAIRMAN WALLIS: Does that answer why the Staff accepted this procedure?

MR. AYALA: The Staff accepted this combination of the 10 percent sampling and the 100 percent examination. We felt that that was a pretty good representative sample size, and that it would provide a reliable information. And we felt pretty comfortable with this, with 10 percent and 100 percent VT-2.

DR. BONACA: But it seems to be me that susceptible locations are those which have a combination of materials, conditions, et cetera, that make them susceptible. And, therefore, the 10 percent is a meaningless number, it seems to me, because you want to simply get sufficient locations, and combinations that you bound all the locations, so you can make an argument of bounding. And so, I guess 10 percent could be adequate, it could be inadequate, but I'm not going to argue about the number in itself.

MR. AYALA: Okay. We have Pat Patnick, wants to address this a little more.

MR. PATNICK: Yes, this 10 percent is also specific to degradation, where the degradations exist. And then this is also subject to expansion criteria. For instance, if they find some degradation, some flaws or something, they'll expand their sample, so we felt that 10 percent is satisfactory based on their operating experience, failures and all that.

DR. BONACA: Yes. The point I was trying to make, again, however, is you're looking at all these locations, and you're looking at materials, and environmental conditions, et cetera. That allows you to determine, to make an argument for all of them, that you're bounding. That may end up being 3 percent, or 8 percent, or 15 percent, I don't know. The number, to me, doesn't mean much.

DR. MAYNARD: I agree. I don't think the percent or the number is as important as the selection criteria. And then, also, the process for if something is found, do you expand. It sounds like that's there.

DR. ARMIJO: Yes. It sounds like their selection criteria said it should be less than 10 percent, but they bumped it up just to be consistent with everybody else. And if their selection criteria was right, then they'll at the riskiest places, or the most important places, and it's probably okay. But it just comes across as a random 10 percent.

CHAIRMAN WALLIS: Exactly.

DR. POWERS: Well, it seems to me that maybe you're right, but we don't see this. We don't see here the materials, here are the locations, here the environment. If I take one from each column, I end up with 5 percent, so I kick it up to 10 percent, and here I've got it. But instead, we say well, the staff is comfortable, the staff is comfortable, the staff is comfortable - Christ, the staff is comfortable. I don't understand how they're comfortable. I don't even see elementary things, like taking a Poisson distribution and saying if I sample at 10 percent, what are the chances that I'm going to miss a bad weld? I see nothing, except everybody's comfortable. Maybe you're too comfortable.

CHAIRMAN WALLIS: Well, the sample you take depends on how many there are. There are 60 butt welds, that's got to be figured into this, too. It appears that there is not a rationale.

DR. BONACA: Well, there is a way - I was insisting before on how the sample is made. There is no mention in the slides from the licensee, nor from the staff, that this one-time inspection, the whole purpose, since you have an ISI program, you're not looking for susceptible location. This is the only opportunity that you have in the life of this plant to look at susceptible locations, and that's why I think it's important, it's known, it's in the GALL report, et cetera, I think it's important that as applications are reviewed, this point is taken, and these answers are provided, because that's important.

MS. LUND: This is Louise Lund. I just want to make a comment specifically about the application, these risk-informed ISI programs. And I think what Pat was trying to get across, too, was that - which you had said, also, about the number not being like the crucial factor, because plant-to-plant, that percentage comes out different, because when they run through it that prioritization scheme, something falls out. But they also have another step where it goes through this committee that looks at it through the eyes of operating experience, a lot of other different factors, to say does this number really look like the right number, or are we comfortable with this number. Say, in fact, if you end up with 1 percent or 2 percent, would you be comfortable saying I really feel like I know what's going on? So I don't think it's all that rare for the plants to be saying even though when I do the prioritization scheme, this is how it falls out. I probably need to put more things in, as a result of that, or this is something that would be a lot more conservative for us to do. And for a while, I was the Acting First Line Supervisor for the group that did the risk-informed ISI, and I knew from looking at some of that work, that's, indeed, what they were doing, or that was the scheme involved.

MR. PATNICK: One other thing to add there, is this will be done in the last five years of the current operating period. And subsequently, when they go into the fifth inspection interval, they'll have to do the regular ISI, which will be probably 10 percent of Class 1 butt welds.

DR. SIEBER: I actually don't recall a lot of rigor being put into deciding how big ISI samples should be. And they are not all that random, either, if you go into the plant and you say I have a choice between inspecting this little one down here, or that one that's 50 feet off the floor, and I've got to build scaffolding to get there, which one do you think you're going to look at?

DR. ARMIJO: But in real life, the one that cracks is 50 feet off the floor.

DR. SIEBER: Is always the one that's up there, right.

DR. MAYNARD: But one of the things I think is an advantage of the risk-informed ISI programs is that it does force a look at the higher susceptibility. It's not just a random, which ones are the easy ones to get to, so I think the risk-informed ISI program is really a pretty good program.

DR. ARMIJO: I agree. I just wish it would have been a little bit more explicit in the presentation.

DR. MAYNARD: I don't think it comes across here, but I think they are taking a look at the susceptible --

DR. SIEBER: Yes, the idea behind it in the old days was that in one ISI interval, which was 10 years, you had to examine everything, so that's 10 percent, if you refuel every year, 10 percent a year. So 10 percent became the magic number, and you applied it to everything, whether it made sense or not.

DR. ARMIJO: It's a little bit better.

DR. BONACA: Yes. No, and I totally agree, the ISI program is a better program. But, as I said, the purpose of the one-time inspection is you wind up saying I'm not going to think about risk, I'm going to think about do I have some degradation mechanism at work that I should be aware of? And so once in the lifetime of these plants is 60 years, literally, I would look at the most limiting conditions in certain location and see if there is, in fact, anything going on. If I don't find anything going on, I can be pretty comfortable that in the next 20 years, between the risk-informed ISI and everything else, I'm okay. So that was the main reason for the comments.

MR. GILLESPIE: I'd like to say, Mario has hit exactly what this one-time GALL issue is. We're not looking for the bad weld, and the 10 percent as GALL, was negotiated, if you would, or discussed with the industry almost in a workshop forum. The real question in a pragmatic way is, how big a sample is big enough to get an indication that you might have to look at more? And so you didn't get a detailed briefing - I mean, they didn't come prepared to give you a detailed briefing on all their selection criteria, and how they picked the 10 percent. I mean, we can do that the next time, with the next licensee, but this is not trying to find on a one-time basis the weld. This is trying to find if there's an indication at that facility for this class of thing, that never gets looked at in the first 40 years, that we can feel comfortable extending that same perspective for the next 20. And so, this is not a statistically selective sample, it is a pragmatic decision at about 10 percent of welds by some criteria that considers location, thermal cycles, vibration, to get an indication, do you have to look at more before we issued a renewed license? And that's the purpose of the one-time piece for GALL.

Then you fall back on your traditional ISI program, which at this plant is a risk-informed ISI program. So it's not trying to find the bad weld at 10 percent. We're not going to be able to show up with a Poisson distribution of why it's 10 percent. I'm not going to say we could.

DR. SIEBER: Yes, actually you spent a lot of time on the --

MR. GILLESPIE: Yes. We understand.

DR. SIEBER: Move forward.

MR. AYALA: Okay. Moving on, there are three analyses that affected by radiation embrittlement identified in the application as TLAAs, the PTS upper shelf energy and core temperature limits. The applicant used 42.37 effective full power years for 60 years of operation. This was using a capacity factor of 91 percent.

For reactor vessel PTS, the limiting

material is the intermediate shell and lower shell axial welds. As a result of the calculation, the screening criteria will be exceeded in 2014. This calculation was confirmed by the Staff. In the next slide, I'll --

DR. BANERJEE: Can you just tell us a little bit about this calculation, go back.

MR. AYALA: This right here?

DR. BANERJEE: Yes, how the calculation was done.

MR. AYALA: How the calculation was done?

DR. BANERJEE: Staff, how you confirmed it?

MR. AYALA: Okay. We have Neil Ray.

MR. RAY: This is Neil Ray, sorry about my voice. First of all, I didn't do this calculation, but as Acting Branch Chief, I'm going to respond to your question. The way it is normally done, is you take them belt line region. The belt line region is defined where the active core resides. So in the belt line region, you look at welds, forging welds. When I say "welds", that includes longitudinal, as well. So those are your limiting - those are the materials, and then you take - you calculate using the initial factor, peak fluence, in this case they calculated up to 2014. And if you have it later, and if they are valid for your plant, you use it to calculate the chemistry factor.

DR. BANERJEE: You had the surveillance capsule data in this case?

MR. RAY: I guess you do. I don't know, since I didn't do myself the calculation, I don't know the answer.

MR. KNEELAND: This is John Kneeland of NMC. We use chemistry numbers. We don't have actual surveillance material that matches the weld of interest.

MR. RAY: That is true, and that is the case. So based on that, there are data with our surveillance capsule, use it. And keep in mind that if you don't have surveillance capsule, your margin term is almost increased, because that is kind of a penalty in the calculation of Reg Guide 1.99 Rev 2. So the folks who are fortunate enough to have surveillance capsule, in general, they get some benefits using the surveillance capsule data. In this particular case, they don't have it, so they used Reg Guide Rev.2 table, and that comes to, in this case, 287, which is slightly higher than screening criteria, and the rest is, I guess --

DR. SHACK: Slightly?

MR. RAY: Yes, it is slightly.

DR. SHACK: Definition of slightly.

MR. RAY: Depending on how you look at it. To me, working in this field for so many years, I would call it slightly, because I was part of the PTS evaluation, and still I am in the part of the current PTS evaluation team. The reason I use the word "slightly", because there are awful amount of conservatism built in the PTS analysis.

DR. BANERJEE: Like what conservatisms?

MR. RAY: Like, for example, in the original PTS analysis, there were some 10,000 - sorry - about 4,500 transients considered, and some of those transients, they were happened. Then if you look at the probability of happening, they were lots of high probability assumed. Keep in mind, in 1986 when the PTS first came to life, we didn't know a whole lot about what the heck we are talking about, so to maintain our vessel in good shape so that it doesn't crack, or the crack doesn't grow, we took extreme conservative efforts. And now after so many years, we know the history, we have inspected vessels so many times for so many vessels, we know what are the flaw, what are the flaw grows or not, all the history we have in our pocket, basically. And we know exactly what we are talking about. That is the difference between 1986 and 2006.

DR. BANERJEE: So where were the conservatisms?

MR. RAY: In terms of your transients, in terms of your probability of failure, and in terms of the assumptions of LOCA, what type of LOCA will happen, what is the probability of happening, all those factors are in there.

DR. BANERJEE: So in the transients in the probability of LOCA, where were the conservatisms?

MR. RAY: The probability was we had shown much higher probability in 1986 than what we are looking at today in the new PTS rule.

DR. BANERJEE: And exactly what was that? That's what I'm after, where was the conservatism?

MR. RAY: The probability of happening itself was much, much higher in terms --

DR. BANERJEE: You mean the probability of a LOCA --

MR. RAY: Yes, in terms of probability of LOCA, in terms of transients, like, for example, in the cycle, temperature, in the seismic cycle, all those were in-built in the 1986 SECY LOCA paper.

And we looked at, as you know, that the new PTS rule is not yet published, but it is going through the process, and I'm not here to tell you what the new PTS rule is doing. That's not my job here.

DR. BANERJEE: So that was the conservatism that you say that probability of LOCA was much higher.

MR. RAY: Yes, just to tell you one.

CHAIRMAN WALLIS: Wasn't there also a big conservatism in the flaw assumptions you put in?

MR. RAY: Yes, there is.

CHAIRMAN WALLIS: That's one of the biggest ones of all.

MR. RAY: The entire flaw generation was different that time versus what we are considering in the new PTS rule.

DR. BONACA: Scenario-wise, for example, steam line breaks were taken never to be isolated, so what you did, you brought the steam line, you fed main feedwater, and you kept feeding until you get the maximum cool down. And the renewal evaluations have shown to be that --

CHAIRMAN WALLIS: Sanjoy, we can give you five volumes of the PTS study.

DR. BANERJEE: I've looked at some of

them, and, therefore, I'm not comfortable. That's why I'm after this.

MR. RAY: I think the point in the previous applicant's presentation they didn't mention, the point is very clear - when we look at it under any circumstances, we do not allow any applicant to operate the vessel when it exceeds the PTS cleaning criteria. That's the bottom line. They have to have come to us three years prior to reaching that point with their analysis, and what they are going to do about it. So that's the current plan, no matter what you say.

DR. BANERJEE: Yes, but to answer Graham's, at least your comment, I'm not so sure that those five volumes tackle all the correct issues in this matter, so it's still open to question. We haven't approved anything, have we?

MR. RAY: This is correct.

DR. BANERJEE: Yes.

MR. AYALA: Okay. Well, moving on to the next slide. The plans are for policies to address PTS are to continue to use an ultra-low-leakage core design, and they must submit three years before 2014 their final PTS resolution. Some of the options that they have are, they can further reduce flux and preheat the safety injection water, as the licensee mentioned earlier, or they perform thermal annealing of the pressure vessel.

DR. BANERJEE: What are the implications of preheating the water? Have you looked into that?

DR. SIEBER: It makes a difference, because if the water that you're injecting is --

DR. BANERJEE: Yes, but I mean, what are the other implications?

DR. SIEBER: Don't get the cooling.

MR. AYALA: Neil, can you address that question for the Staff, please?

MR. RAY: I didn't hear the question.

DR. BANERJEE: What are the implications of preheating the water? This is being offered as a possibility.

MR. RAY: Well, if you look at the PTS scenario, what is happening, you have a very high temperature vessel with a high pressure, and the typical scenario under that, you are pouring cold water, that's the scenario.

DR. POWERS: I think he's not asking you what the implications are for PTS.

MR. RAY: I know. No, the one solution, potential solution is the right one, is to increase the temperature so that your differential T, Delta T will be reduced.

DR. POWERS: I don't think he's asking about that. I think he's asking you, if I've got a bunch of hot water in a pipe, what does that do?

MR. RAY: Well, that water eventually will be poured into the vessel.

DR. POWERS: He's not asking you about that. He's asking --

MR. RAY: The Delta T is different. That's the purpose of safety injection, hot water safety injection, preheating that safety injection.

DR. POWERS: What happens during operation when you run the hot water for years at a time?

MR. RAY: In typical PTS scenario, when anything happens --

DR. POWERS: I'm not interested in the scenario. I'm interested in what are the operational implications of having hot water available for ECCS injection?

MR. RAY: I'm not following your question, really.

DR. POWERS: The question is, what are the implications of having hot water available for ECCS injection?

CHAIRMAN WALLIS: You're asking if it changes the --

MR. GILLESPIE: Neil, let me try this. What are the negative implications of changing the system operation of high pressure injection to include hot water?

MR. RAY: Oh, okay.

MR. GILLESPIE: Does this degrade the high pressure injection system? Does this introduce fatigue cycles into that safety system?

MR. RAY: That is correct.

MR. GILLESPIE: That's the question.

CHAIRMAN WALLIS: Does it change the peak clad temperature?

MR. RAY: Yes.

CHAIRMAN WALLIS: It does, but does it change it significantly?

DR. BANERJEE: Does it affect long-term cooling? There's a whole lot of --

CHAIRMAN WALLIS: It does all kinds of things.

DR. SIEBER: The answer is yes to all those questions?

CHAIRMAN WALLIS: So I think we could probably move on. We've established you just don't put hot water in without thinking about all the implications.

MR. RAY: That is very true.

DR. MAYNARD: But I also don't think that they presented these options as things that were totally founded. These are possibilities that would have to be further evaluated. I don't think they presented them as final solutions.

MR. RAY: I think I totally agree with your observation. This is just a potential solution only, and the whole idea is before they reach to that point in 2014, there will be several other options, including the new PTS rule. That's the whole approach.

DR. BANERJEE: Nobody should count on it.

MR. RAY: Yes, nobody should count on it. I agree with you, but from staff's point of view, if the new PTS rule doesn't come or so, then they have the options of Reg Guide 1.15 for analysis, which is a potential, and as they said, annealing is a potential. Everybody will laugh at me, nobody does annealing in this country, but Russia has done several times, and they're successful in that. And the worst option is in that case, the plant shutdown. So that is also an option, as well.

DR. SIEBER: Just to maybe put a cap on this discussion, I would point out that in PWR tech specs, there is a maximum temperature for safety injection water specified, so that the system will perform and be able to cool the core, remove heat. And, so, when you are contemplating increasing safety injection water, you've got to keep in mind that there's a limit as to how far you can do that, without compromising the operation of the system.

DR. MAYNARD: They'd have to redo their safety analysis --

DR. SIEBER: They've got to do a lot of work to do that.

DR. MAYNARD: That would be a lot of work, yes.

DR. SIEBER: You have to modify the plant, because you don't have heaters in the RWST.

DR. MAYNARD: There would be a lot of modification, and complete redo of safety analysis.

DR. SIEBER: Yes.

DR. MAYNARD: Thermal hydraulics, everything.

DR. SIEBER: I suspect that we've probably exhausted this subject. We have actually three issues on the reactor vessel. This is one of them, where they run into a problem with screening criteria before the end of the extended period of operation, so why don't we move to the next one, which is upper shelf energy.

MR. AYALA: Okay. For reactor vessel upper shelf energy, the limiting plate is the lower shelf plate, and it is expected to exceed the acceptance criteria in 2021. This calculation was also confirmed by the Staff, and I'll discuss this in the next slide. The limiting weld is the intermediate lower shelf circumferential weld. The analysis is acceptable, and this calculation was confirmed by the Staff.

DR. SIEBER: I would point out that when you give a date, the criteria is really how much fluence the vessel receives, and not how long it's in operation. So you're saying that if the plant runs at 90 percent power or capacity factor, that will deliver the dose of fluence that is critical in this calculation by such and such a date. And that date can move, depending on the capacity factor.

MR. AYALA: That's correct.

DR. SHACK: I mean, I hate to bring the issue up, but if you go back to the next slide, I think you have the answers interchanged in the last column. The 48.97 is, in fact, acceptable, and the 50.83 presumably exceeds the criterion.

MR. AYALA: Yes, 48.97, the upper shelf energy has to be greater than 50 --

CHAIRMAN WALLIS: Greater than 50.

MR. AYALA: So it's lower.

CHAIRMAN WALLIS: Here's your subject, Bill.

DR. SHACK: My mind is just going.

MR. AYALA: Oh, okay. The Palisades plans for exceeding upper shelf energy criterion in the lower shelf plate is to submit an equivalent margin analysis three years before the expected - when they're expected to exceed the criteria, which right now it's 2021.

For pressure temperature limits, they are expected to expire in 2014.

DR. SIEBER: Right.

MR. AYALA: The plan for exceeding the limits will include to update the limit and curves to include additional fluence accumulated during the period of extended operation. This will require updating the technical specifications, and this will be managed using the reactor vessel integrity surveillance program.

DR. SIEBER: Now, in this case, it's just the curves expire.

MR. AYALA: Yes, it's the curves expiring.

DR. SIEBER: And you can always generate new curves.

MR. AYALA: Right.

DR. SIEBER: And you can put them in your tech specs. The question then becomes, can you actually operate the plant, and are they the curves?

CHAIRMAN WALLIS: That's right. What does it do to plant operation when it changes?

DR. SIEBER: And that's up to the operator to decide. He may not be able to heat up the plant, because he doesn't have the room on the curve to do it.

CHAIRMAN WALLIS: It's not managed by a plant operator.

DR. SIEBER: That's the way it goes.

CHAIRMAN WALLIS: But this isn't managed by a program. It actually constrains what you can do in the plant.

DR. SIEBER: That's right.

MR. AYALA: The program will - I guess part of their program is that they're going to provide these updates, and they're going to come in and make the revisions. They do have to look at their current operating, what the neutron fluence is, that they have accumulated since the last calculation was approved, so they will take into consideration --

CHAIRMAN WALLIS: The question about how you operate the -- if you have much narrower PT limits, there's more likelihood of exceeding them. And so you ask then, what's the consequence of exceeding them? It also becomes a risk analysis.

MR. AYALA: Neil Ray is going to make a comment on this.

DR. SIEBER: That's true.

MR. RAY: Actually, it's a kind of tradition to have the PT limits at different EFPYs. To give you an example, like, for example, if any plant is say at 20 EFPY today, they normally have the operating PT limits is probably, say, 30 or 32 EFPY effective PT limits, or they can have, say, 24. But the idea here, before they reach 24, they regenerate their PT limits and submit to us for review and approval. But if they're in the PTLR area, and if they don't change any methods, in that case they don't have to come to us. They simply update their PT limits, and give it to their operators, and they operate at that. So I think one question raised about the applicability of PT limits if there is enough window - well, let me put it this way - in the good old days, we used to generate PT limits using K1R in the fractured toughness area, but after that, with the ASME code and all the technological experts who use K1C, and that gives a huge margin. And other areas, for example, the short weld versus long weld, we give some benefit, so I don't know of any particular plant in the PWR area today has any problem in their operation in terms of window, because of those benefits they get enough widening of windows so they should not have any problem whatsoever.

DR. SIEBER: Yes. Let me point out that these three issues with the Palisades reactor vessel are three of quite a number of time limiting aging analysis. The fact that the analysis that they have on record for their plant, the fact that it doesn't go all the way through the period of extended operation does not preclude the Staff from issuing a license extension.

On the other hand, Palisades may not be able to run the plant for that extended, full extended period of operation until they comply with the rules, so it's not inconsistent that the Staff would issue an SER, and perhaps a renewed license, keeping in mind that these issues have to be solved by the licensee to allow the plant to run for the period of the license. And it doesn't make any difference whether the license is renewed or it's the original license, the same rules apply, and those rules take precedence over the license term.

MR. AYALA: Okay. If we can move on to the confirmatory item that we had in our initial SER. WCAP-16605-NP is a plant-specific version of the Staff-approved Westinghouse WCAP-15338-A. This plant-specific WCAP includes plant-specific, or plant-designed transients, as the applicant mentioned in their application. And the bounding nature of the analysis from the Staff-approved WCAP also applies to Palisades.

The Staff found that for under-clad flaws with an aspect ratio of 2 to 6, the amount of growth cited in WCAP-15335-A are the same for Palisades. The fatigue crack growth analysis uses the designed transients applied, stress intensity factors as inputs, and the Staff found that the concerns are resolved for this confirmatory item.

DR. ARMIJO: Do they take into account the radiation hardening where these cracks exist? Maybe Bill knows.

MR. AYALA: Neil, can you address that for the Staff, please?

MR. RAY: To answer your question, the answer is yes, we have to do it. That's the standard practice.

DR. SHACK: I'm sure your fatigue crack growth curve is all determined on materials, that it's not radiation hardened.

MR. RAY: That part is true.

DR. SHACK: I think that was your question, wasn't it?

DR. ARMIJOY: Yes, that's it. So is there a correction factor, or a guess on how much that affects the crack growth rates?

MR. RAY: I did not look at the WCAP recently, so I cannot really answer that question. And, as I said, I didn't do my analysis myself, so I'm not really sure whether there is any penalty factor or not. But based on my recollection, because I did myself the Pineridge analysis, and I don't believe - there are some basically rule of thumb criteria, and that basically, they follow it, and as long as it is within that umbrella, that's okay. That kind of analysis we are talking about here.

DR. SIEBER: Well, we're behind now about - if you ended now, it would be 10 minutes. Can you rush to the end?

MR. AYALA: Yes. This is my final slide. The Staff has concluded that there's reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the current licensing basis, and the regulation. And that ends the Staff's presentation. If you have any additional questions, we can answer those for you.

CHAIRMAN WALLIS: We are not going to comment on this one.

DR. SIEBER: Okay.

MR. AYALA: Okay. Well, thank you very much.

DR. SIEBER: Additional questions? If not, we do have a member of the public, Mr. Kevin Camps, if you could come to the microphone. You can make your statement, or you can go up in the front of the room.

MR. CAMPS: That microphone?

DR. SIEBER: Any one is okay.

MR. CAMPS: Well, thanks for this opportunity to speak. My name is Kevin Camps from Nuclear Information and Resource Service, and I'm also on the Board of Directors of Don't Waste Michigan. And I speak today on behalf of 36 organizations in Michigan, including Michigan Environmental Council, which is a coalition of 72 groups, the League of Women Voters, just to name a few.

We've taken part in all of the NRC proceedings related to the Palisades license extension over the course of the past two years. We've intervened at the licensing board, we've attended all the technical meetings at Palisades that we knew about, anyway. And we've tried to monitor the ACRS Subcommittee, and this full committee, as well. And we still have tremendous concerns about certain issues, including pressurized thermal shock and embrittlement.

One of the comments that I have is that at the July 11^{th} subcommittee meeting of ACRS, we had a number of questions presented by a number of groups that were present by telephone that day, and we're not pleased with the lack of response from NRC staff on our questions. We had some very straightforward questions, and I think just listening today to some of the discussions, I picked up some answers to those questions. We had questions about metal coupons in the reactor, and it seems pretty clear now that there's a lack of those, but we've never been told that directly by NRC staff. We've been told that our questions are out of scope; and, therefore, there would be no answers provided. And that's not sitting well at the grassroots level in Michigan, among these hundreds of thousands of members of these organizations who are closely monitoring these proceedings.

I think another comment I'd like to raise today, and it did come up again, several members of the ACRS said that the proposed rule change to the PTS screening criteria cannot be counted on, but I think any objective observer who's watching these proceedings sees that Nuclear Management Company, Consumers Power, Entergy, all of the parties to this impending sale of the plant, which hundreds of millions of dollars, if not billions of dollars are at stake, are very much depending on the weakening of the PTS criteria to allow this plant to operate for 60 years. And our question is, how can these decisions, which are now more expedited than they were before, dates have been moved up for final decisions, ahead of an already expedited schedule, so we're talking by spring of 2007 final decisions will have been made on the 20-year license extension.

How can these decisions be made, when that rule is still pending? It has not taken place, it will not have taken place by then, so it seems like final decisions on a 20-year license extension would have to wait at least until that rule is in place, because those decisions would count on that rule. It's pretty clear. I mean, this is three years into the extended operations, 2014, so that's a very short time into the license extension, so why would the license extension be granted when three years into it there could be a very major problem?

And I've heard speakers say - I couldn't see everybody because of the column, so I don't know who said it - but someone on ACRS said well, the license extension could be granted, but the company, whoever owns it at that point, would have to obey the rules. I think there's an element of real politics to be considered here. With billions of dollars at stake, a 20-year license extension already granted, I think there's going to be a little bit of pressure to make that rule change happen come hell or high water, and we see the writing on the walls with this. There's tremendous concern on the ground about this reactor. It's not only the PTS problem, it's other age-related degradation at the plant, it's the lack of a solution for the high-level waste that's stored there. I know that NRC brushes that off with the Nuclear Waste Confidence Decision, but we have concerns that the dry cask storage at the plant, which has been ruled, again, out of scope for the license extension, already is in violation of NRC safety regulations, specifically earthquake regulations. So we see - I know this isn't the Advisory Committee on Nuclear Waste, but we see a problem with generating 20 more years of nuclear waste where there's nowhere to store it at Palisades, because of this violation of earthquake regulations.

Another comment I'd like to make is about the deferred inspections, the reactor internals inspections. That was another question we had, and it seems, again, that we haven't gotten clear answers on those questions. And they're playing a very major role in your decisions here, so I would just encourage the ACRS to take these issues very seriously. There are literally hundreds of thousands of people in Michigan belonging to these organizations who are very concerned about these issues. And we will continue to follow this at every turn, and we will bring to bear as much expertise as we can afford. I did ask the subcommittee if there's any funding available. I know there is on the Canadian side of the border; when public intervenors have concerns, there's funding made available so that they can hire their own expert witnesses, so we're actually holding fundraisers on the ground in Michigan to hire our own expert witnesses to try to evaluate, especially the PTS proceedings. And we will do our best to offer that expertise to help with your decision making, and with your analysis. So thank you for this opportunity.

DR. SIEBER: Okay. Thank you very much. If there are no further questions, or comments, Mr. Chairman.

DR. APOSTOLAKIS: Yes. I'm curious, why didn't the Staff respond to the questions?

MR. GILLESPIE: The Staff did respond.

DR. APOSTOLAKIS: Did?

MR. GILLESPIE: Yes. What we did not respond to is the out of scope questions, which is high-level waste. They, in fact, are out of scope, so there's really two answers to the question. Did we respond to the questions that were appropriate? We feel we did. Did we respond to the questions that were out of scope, such as high-level waste and security? We also said there's other avenues. There's 2.206 petitions, and there's other avenues for those to be addressed, and those are not within the scope of license renewal, so it's a mixed answer.

MR. CAMPS: Well, I would agree that we heard those responses, but we took all those avenues. We have 2.206 petition proceedings. What I was specifically referring to were questions asked at the ACRS subcommittee on July 11th, having to do with such things as metal coupons being available or not, with reactor internal inspections being deferred into the future so that they don't take place before this license renewal is granted. And to the best of our understanding, the responses from NRC were that these questions, as well, were out of scope on this proceeding, and would not be further answered. And so that's why we're so displeased.

It seems like from the discussion I just witnessed here, they're very much within scope. ACRS members were asking very similar questions. We asked these questions several months ago, and didn't receive an adequate response.

MR. GILLESPIE: I think that's the key to it, the response wasn't viewed by the party that received it as being the answer they wanted, or adequate on their part, but we would be happy to supply the committee with a copy of our response to their concerns.

DR. SIEBER: I think we already have it.

DR. KRESS: Is it true that the dry cask storage is in violation of earthquake regulations?

MS. LOUGHEED: This is Patricia Lougheed from the Region 3 office. I apologize I'm on the phone. We do not currently have any violations on the dry cask storage. There is an unresolved item that is being reviewed, which I believe is also the subject of a 2.206 petition. That is unresolved. It is being inspected by our dry cask storage expert here in the region with help from people in NRC Headquarters. And, again, there's not a current violation.

MR. CAMPS: Could I respond to that,

please? Dr. Ross Lansman, who was the NRC Region 3 dry cask inspector, first raised the concern of earthquake regulations violations in 1994, and he is serving as our expert witness, both at the licensing board proceedings, as well as in this 2.206 petition. And, perhaps, a future legal action in the federal courts on this matter. And so it has been 12 years since Dr. Lansman in his capacity as NRC Region 3 dry cask storage inspector raised this concern, specifically that the cask pad closest to the lake, just 150 yards at most from the water of Lake Michigan, is built on 50 plus feet of loose sand; that Consumers Energy did not address the loose sand, they did their calculations on earthquakes, assuming that this was a bedrock situation. This cask pad is not anchored to bedrock, so it's the amplification, and it's the liquifaction that would take place because of the loose sand that's of concern. Casks could be buried under sand, casks could end up under water, you could have a nuclear criticality in the cask if water infiltrates the cask, you could have overheating if it's buried under the sand.

We've been raising these issues, both Dr. Lansman and ourselves, for over a decade. And when

NRC Region 3 says it's under review, it's not a violation, Consumers has proceeded to load 29 or more casks on these pads which are under review, and that's why we find this so outrageous.

As I speak, Consumers is allowed to continue to add casks onto these pads that we allege are in violation. And Dr. Lansman, who recently retired just a year or two ago, for over a decade alleged were in violation of NRC regulations. So our question is, does NRC enforce its own regulations? And it comes back to this question of the license extension.

People have said oh, if the license is extended, the company is going to have to live up to NRC regulations. That's not been our experience on the ground at Palisades, and I think, perhaps, you can see our concern.

DR. SIEBER: Yes. If there are no other questions or comments, Mr. Chairman, I turn it back to you.

CHAIRMAN WALLIS: Yes. Well, I'd like for us to take a break, but I would say that as far as my personal view as the Chair, I think it's very useful to have public comments, particularly when they are well-informed on technical matters. That really is very helpful to us.

I'd like to take a break for 15 minutes, until 20 minutes before 11.

(Whereupon, the proceedings went off the record at 10:27 a.m., and went back on the record at 11:05 a.m.)

CHAIRMAN WALLIS: Please come back into session. We are behind. We will do our best to catch up.

Jack Sieber is also the lead ACRS member on this next item, Fire Protection for Operating Nuclear Power Plants. If we don't have the slides ready, I would like to move on and we will just read the slides that we have in hard copy.

MR. RADLINSKI: Okay. Is this on?

CHAIRMAN WALLIS: So, Jack, please go ahead.

MEMBER SIEBER: Yes, in the interest of saving time, I'll just turn it over to the staff to begin their presentation.

MR. RADLINSKI: Okay. So you're not going to make any introductory remarks based on what we talked about yesterday or anything? All right.

For those of you who don't know me, my name is Bob Radlinski. I'm a Fire Protection

Engineer. I'm in Sunil Weerakkody's Fire Protection Branch. And we had a subcommittee meeting yesterday where I went through a description of all the changes that are being made to both Reg Guide 1.189 for fire protection and the standard review plan for fire protection, SRP Section 9.5.1.

We covered a lot of different topics that were identified as issues that Dr. Sieber wanted to talk about, discuss yesterday. Today I'm only going to discuss or describe the changes that are being made to these two documents.

So with that, we'll start with slide number -- my slide number nine. But with the handout that you have today, it is the first slide.

The first slide is a summary of the significant changes that were made to the Reg Guide, okay? And I'll go through each of these individual items in greater detail in the subsequent slides.

The Reg Guide is revised from the original version. It has added guidance and acceptance criteria for new reactor fire protection programs. The original Reg Guide was issued in 2001 I believe. And there was nothing in there about new reactor plant fire protection programs. So that is all new for the Reg Guide.

We also had a guidance based on the recent generic communications that have been issued from the Fire Protection Branch to clarify regulatory requirements for circuit issues and for operator manual actions. Those were included in a couple of RISes that are identified there.

We also added new guidance on post-fire safe shutdown circuit analyses and how to treat multiple spurious actuations in the post-fire safe shutdown analyses. That guidance is essentially what is included in a draft generic letter that the ACRS has reviewed. It is with the Commission right now for notations so it has not been issued as yet.

Furthermore, we replaced or we are proposing to replace the Generic Letter 86-10 approach to evaluating changes to a fire protection program and revert back to 10 CFR 50.59 as the basis for making those changes. And as I mentioned, we will get into more detail about each of these items later.

We added guidance on the use of fire PRA and fire modeling. And that would be for plants that are not adopting NFPA 805. The Reg Guide update as well as the SRP update apply only to plants that are non-805 plants. There is a separate

Reg Guide for plants that are transitioning to 805. And there will be a separate SRP section generated for those plants as well.

And finally, we added some additional terms to the glossary, clarified some of the terms that are already in the glossary in the Reg Guide just to bring those up to current regulatory expectations.

MEMBER SIEBER: I would point out that one of the issues that came up yesterday was an item in the glossary called important to safety. And what it really means, the staff has agreed to expand on the definition of that term so that it become more clear as to what the expectation is of the licensees when the term important to safety is used.

MR. RADLINSKI: Okay. To get into some more detail on the guidance and the criteria that were added for new reactor fire protection programs, there is an enhanced fire protection criteria that has been -- I don't know if dictated is the correct word but the Commission has directed us to include enhanced fire protection for new reactor plants.

For those of you who are not familiar with that, the enhanced fire protection includes complete -- well, it is similar to III.G.1 if you are familiar with Appendix R. It includes complete three-hour structural fire barrier separation between each of the redundant trains.

It also requires licensees to assume that in the event of a fire in any one of these areas, there will be no access during the fire or after the fire to take any action within the fire area.

MEMBER SIEBER: Other than the fire brigade putting out the fire.

MR. RADLINSKI: That's correct.

MEMBER SIEBER: Because that is allowed.

MR. RADLINSKI: That's right. This would be for any operator manual actions-type thing.

The other aspect of it is the enhanced fire protection is that the plants will be designed that smoke and heat from the fire in one area cannot migrate to an adjacent area and take out more than one train.

Another issue that we have added or addressed in more detail in the update is the applicability of industry codes, including NFPA 804, which is a code, an industry code that has already been issued by NFPA. It is for a deterministic-type fire protection program and it applies to new reactors.

There is another code, NFPA 806, that is being drafted right now that has not been issued. And that is for the risk informed performance-based-type program for new reactors.

We've added a description or a discussion of the passive plant shutdown definition for new reactors that use passive cooling for shutdown. And also we've added a little bit of discussion on fire protection program implementation for new reactors, basically the logic or schedule logic during construction and start up of the plant and when those programs should be in effect.

The update in Reg Guide also includes recommendations that new reactors minimize reliance on certain aspects, certain features of the fire protection programs that are prevalent in existing reactor plants. One of those is the alternative/dedicated shutdown system, the concept of if you can't provide the protection of III.G.2, then you go to III.G.3. And provide an alternative.

Obviously the control room is an area where that is still going to be required. But otherwise, the recommendation is that with a plant being designed from scratch, there should not be any reliance on that type of approach for fire protection and safe shutdown.

Another is the use of operator manual actions. As we know, they are very prevalent in existing plants. And, again, they should not -- licensees should not have to rely heavily on operator manual actions in a new reactor either during or after a fire.

And finally, local electrical raceway fire barrier systems, fire wrap on an individual tray that is passing through an area has a redundant train. With the enhanced fire protection, there should be none of that in the new reactors.

MEMBER MAYNARD: Well, I think the key in here it says minimize reliance. It doesn't say eliminate because there are some times when there will be some. And I think that one of the things you guys are going to have to be thinking about is what do you really mean by minimize and what is going to be an acceptance criteria.

MR. RADLINSKI: Right, right. Where it is feasible. Obviously things are going to have to come together at some point. And there will be areas where they can't have complete separation and they may have rely on these. But, again, the recommendation is to minimize them.

Another approach for avoiding potential problems with multiple spurious actuations is to have a self-induced station blackout, okay, so that you reduce the amount -- the possibility of hot shorts and spurious actuations. That is an approach that some plants use today. And we would not expect that to used as an approach for a new reactor plant.

And finally, we added a little discussion on fire protection for non-power operations. That is during shutdown, maintenance outages, mainly having to do with fire prevention.

As I mentioned before, we have included the guidance on regulatory expectations with respect to a number of topics that were issued in generic communications, RISes in particular. We incorporated RIs 2005-30 with respect to circuit issues with the guidance that post-fire safe shutdown circuit analyses must consider any and all hot shorts and spurious actuations. And further discussed or defined what associated circuits mean with respect to post-fire safe shutdown circuit analyses and what they don't mean.

The other RIS that we have incorporated is the one on operator manual actions which says that you can't credit an operator manual action as a substitute for III.G.2 protection in an area where you have two redundant trains in the same fire area without submitting an exemption request and getting approval.

MEMBER APOSTOLAKIS: So that regulatory guide that we saw some time ago where they calculated the time margins -- it was not a guide, it was, I think, a NUREG -- they calculated the available time before you reach an undesirable situation.

MR. RADLINSKI: Right.

MEMBER APOSTOLAKIS: And then they calculated the times to diagnose and decide what to do. And then the sum of these had to be less than the available time by a certain margin. All that is now nothing? It's not used by anybody?

MR. RADLINSKI: No, no, it is included as a reference. It is suggested as a guide.

MEMBER APOSTOLAKIS: For exemptions? Is that for exemptions only?

MR. QUALLS: Well, let me talk about that just a little bit.

My name is Phil Qualls. I have worked in the Fire Protection Section. And I was integrally involved with the whole manual action issue since it started.

What you initially saw was a Reg Guide when we proposed the change to the regulation. What we have done with research -- our research has done has converted the Reg Guide into a NUREG so you may have seen a draft NUREG that is going out soon for public comment if it is not out for public comment already.

MEMBER APOSTOLAKIS: I have seen it, yes.

MR. QUALLS: It is right at the cusp of going out for public comment which incorporated the manual action criteria for a successful manual action. Now that criteria including the time margin was -- keep in mind applies only to the performance of the manual action itself, not its acceptability in lieu of a fire barrier for which you might have to address several other defense in depth issues.

But, yes, the stuff has not gone away. We still have maintained -- that's the guidance and it is going out for public comment in the draft NUREG.

MEMBER APOSTOLAKIS: How is this first sub-bullet effecting this NUREG? That's not very clear to me.

MR. QUALLS: Which one?

MEMBER APOSTOLAKIS: It says operator

manual actions may not be credited in lieu of required III.G.2 protection.

MR. QUALLS: For pre-'79 licensees, they require an exemption to not meet verbatim or the specifics of III.G.2 of Appendix R. So they would have to get an approved exemption.

MEMBER APOSTOLAKIS: And in preparing the exemption request, they could use this NUREG?

MR. QUALLS: They would use that for evaluating the manual action but it might not be sufficient without addressing other defense in depth issues.

MEMBER APOSTOLAKIS: So post-1979 what happened?

MR. QUALLS: Post-1979 plants may make changes to their approved fire protection program unless those changes adversely effect safe shutdown. So again, they would have to, for their internal evaluation address the NUREG issues. They may not -- they don't have to -- let's understand. A NUREG is a NUREG. You may not have to do the time margin. There may be other ways of addressing the time margin for simple manual actions that happen late.

But they have to -- they should do an evaluation that does not adversely effect safe shutdown. So they would have to address the defense in depth items also.

MEMBER APOSTOLAKIS: But the only use that we can foresee for that NUREG now is for exemption requests. Is that correct?

MR. QUALLS: That is one use. They can also be used for licensees in their evaluations for the post-'79 plants.

MEMBER APOSTOLAKIS: It's not clear to me what '79 means.

MR. QUALLS: Well, pre- and post-'79. Pre-'79 plants have to meet Section III.G.2 of Appendix R --

MEMBER APOSTOLAKIS: Right.

MR. QUALLS: -- which states you shall have a one-hour fire barrier.

MEMBER APOSTOLAKIS: I know that.

MR. QUALLS: Post-'79 plants do not have to meet that. They have to meet their approved fire protection program as it is listed in their license condition. And they may make changes to that if they determine that it doesn't adversely effect safe shutdown.

MEMBER APOSTOLAKIS: And they may make changes but have to be approved by the Agency.

MR. QUALLS: If it adversely effects safe shutdown, it needs prior approval. And their determination may use -- and it is up to them, of course, may use some of the guidance in the draft NUREG.

MEMBER APOSTOLAKIS: Well, I mean the whole point -- because this is very relevant to something else we are going to deal with at this meeting -- this NUREG is not just somebody's research. It is something that may, in fact, be used in the regulatory arena.

MR. RADLINSKI: Right.

MR. QUALLS: Yes, it may.

MR. RADLINSKI: It may also be used by inspectors.

MEMBER APOSTOLAKIS: Absolutely, yes.

MR. QUALLS: As a matter of fact, there has not been -- when we first started, I first started looking at the manual actions issue about four or five years ago due to some violations, I couldn't find anything else that the NRC has in any other -- outside of fire protection for the rest of the Agency that really addressed ex-control room manual actions.

MEMBER APOSTOLAKIS: In a deterministic

world.

MR. QUALLS: In a deterministic way, right. And that was --

MEMBER APOSTOLAKIS: You are right. There isn't anything. Thank you very much. This was very good.

MR. RADLINSKI: Okay. The second bullet there is just one of the other key points that are made in this RIS. And that is that where you have -- where a licensee has provided III.G.2 protection for one success path, then it is acceptable to use operator manual actions for the redundant train if necessary.

As I mentioned before, the guidance for multiple spurious actuations that is in the revised Reg Guide is consistent with the generic letter that is in a draft form right now that says that post-fire safe shutdown circuit analyses should address multiple spurious actuations. It also must consider the fact that spurious actuations may occur in rapid succession without time to mitigate the consequences.

And also specifically notes that a one-at-a-time approach to evaluate a multiple spurious actuation does not comply with -- okay, again the one-at-a-time approach that has been used by a number of licensees, we specifically note that that is not in accordance with fire protection regulatory requirements.

All right. This next issue is something that was recently decided upon to add to the Reg Guide, the Fire Protection Branch. And this has been discussed with management at higher levels in NRR. And they have agreed to this approach.

What we would like to do -- well, for those of you who are not familiar with the 86-10 approach to evaluating fire protection program changes, 86-10 introduced the concept of a standard fire protection license condition which allowed a licensee who adopted this license condition to self approve changes to the fire protection program so long as they did not adversely effect safe shutdown, okay.

And as it was originally written in 86-10, it was that they had to follow this approach in addition to meeting the criteria of 10 CFR 50.59.

In 2000, the industry -- NEI persuaded the NRC to exclude fire protection from 50.59 which meant that the 86-10 no adverse effect on safe shutdown criteria was the only criteria that licensees needed to meet to self approve a fire protection program change.

What we want to do for the new reactors only -- and this is not a retrofit or a backfit to existing reactors -- for new reactors we want to revert back to 50.59 and not have this concept of 86-10 no adverse effect on safe shutdown criteria. That would make fire protection consistent with the rest of the plant and the other systems.

50.59 provides a more definitive set of criteria for assessing a change and whether or not it can be self approved. And --

MEMBER APOSTOLAKIS: What would it take to also apply to existing reactors? To reverse, in other words, the decision.

MR. RADLINSKI: There would be a cry of backfit. That would be it, yes.

MEMBER APOSTOLAKIS: Really?

MR. RADLINSKI: New staff position.

MR. QUALLS: The way the different regulations are written, the current generations of plants each have a license condition which provides that they may make changes as long as their changes do not adversely effect safe shutdown. And as I understand it, the way the revised 50.59 that was revised several years ago is words that is written is that if you have a different means of controlling changes, that that is the alternate to use instead of 50.59.

So when NEI and NRC together we endorsed an NEI document which excluded fire protection from meeting 50.59 on the bases that it must meet the approved fire protection program of their license condition.

Now for the advanced reactors, the new reactors, as I understand it, the Commission in one of the meetings that has been held, does not want a license condition for fire protection. They want to simplify the license.

So if they simplify the license and do not have a specific license condition for fire protection, that means that they will have to comply with 50.59 for plant changes instead of a license condition because they won't have a license condition.

That's how I believe the situation is. And that is what you see on the bullet here.

MEMBER MAYNARD: Well, I take exception a little bit to the way it was presented. That like the industry and NEI had somehow convinced the NRC to do something that they should have been doing.

And in reality what happened was two requirements were being imposed. You had 86-10 or 50.59. And it went to one change process and 86-10 was decided on at that time rather than imposing both change processes on it.

I don't think that, you know, with the new plants and stuff imposing 50.59 and not having a duplicate deal is going to be a problem area. But you do not need to --

MEMBER APOSTOLAKIS: It appears we have one regulation for existing plants and one for new.

MR. RADLINSKI: Right.

MEMBER APOSTOLAKIS: So that is the price you pay for not going through backfit.

MR. QUALLS: Well, in the future, one of the problems we had, I have only been working with the fire protection stuff for about 20-something, a little over 20 years. And one of the problems we have had --

MEMBER APOSTOLAKIS: Is that enough you think?

MR. QUALLS: Yes, one of the problems I have had as an inspector and stuff is fire protection is always -- in many areas it has been kind of outside the mainstream of NRC regulation.

MEMBER APOSTOLAKIS: Yes, okay.

MR. QUALLS: Okay, it has got its own license condition. You don't have to meet 50.59. You make changes via the 86-10 process, et cetera.

One of the things we have been doing is trying to, over the last several years, have been trying to pull fire protection back into the mainstream of NRC operation, you know, so we try to get it under what used to be in Generic Letter 91-18 for nonconforming conditions.

And now they are trying to just let it be controlled by 50.59 instead of a license condition that kind of sets it off from everything else.

MEMBER BONACA: This is just a question to understand better. It seems to me that the GL 86-10, I mean the allowance to make changes as long as they have no adverse effect on safe shutdown is much less prescriptive than 50.59, right? 50.59 just sends you to a set of questions and you have to --

MR. QUALLS: Well, if you get -- it is in theory. But if you get down to the details of what was in the generic letter, it defined a lot of stuff for the 50.59 that was in existence in 1986. So it did give like a page of description on how people needed to implement that license condition at that time.

MEMBER BONACA: So there is an equivalency you feel?

MR. QUALLS: It should be. It should be.

MEMBER BONACA: All right.

MR. WEERAKKODY: Yes, one of the -- sorry I was late. I just got here.

PARTICIPANT: Who are you?

MR. WEERAKKODY: I'm Sunil Weerakkody, Branch of Fire Protection. And yes, I did sleep well last night.

MEMBER APOSTOLAKIS: He did sleep. Last time he said he had difficulty.

MR. WEERAKKODY: I looked at my calendar.

It appears more flexible because it is a single word as opposed to 50.59 which has a number of criteria. But based on my last three years of experience, actually for licensees a number of them aren't, you know, really pleased with that because whenever they make a change, they understand that they can easily be second-guessed, okay?

The inspectors could go in and say hey, you told us that had no adverse effect. We don't. And then they might prevail. And that would be a violation. So, you know, we are going to put this out for public comment. And have a good --

MEMBER BONACA: The bottom line is that they go through that but they really go through the questions of 50.59, too, in their mind.

MR. WEERAKKODY: It is very, yes, you know, it is very flexible. And that, you know you would think that the licensees would like it. But really it kind of keeps them on edge when they make changes.

MEMBER BONACA: Yes, okay. I understand. Thank you.

MR. RADLINSKI: Okay. The update to the Reg Guide also includes guidance on the use of fire PRA and fire modeling. It is very much like what we included in Reg Guide 1.205 for the plants that are going to 805, NFPA 805, risk informed performance-based program.

It is appropriate that the same guidance, same regulatory positions apply to both non-805 and 805 plants with respect to PRA and fire modeling.

MEMBER APOSTOLAKIS: Do they have to do the PRA if they don't convert to 805?

MR. WEERAKKODY: No, they do not. But --

MEMBER APOSTOLAKIS: So what type -- what do you mean by for use of non-805 plants?

MR. RADLINSKI: For exemption requests, license amendments.

MEMBER APOSTOLAKIS: Oh, okay, okay.

MR. RADLINSKI: These are plants that have not committed.

MEMBER APOSTOLAKIS: But why would 805 be voluntary for future plants -- oh, this is not just future plants.

MR. RADLINSKI: No. This is for all plants.

MEMBER APOSTOLAKIS: But is it still voluntary for future plants?

MR. RADLINSKI: Well, for new reactors.

MEMBER APOSTOLAKIS: That's what I mean, yes.

MR. RADLINSKI: All right. For new reactors --

MEMBER APOSTOLAKIS: What is the difference, by the way? New reactors, future plants?

MR. RADLINSKI: Well, it is the Office of New Reactors so that kind of --

MEMBER APOSTOLAKIS: Oh, I'm sorry. It is the official nomenclature. I'm sorry.

MR. RADLINSKI: That is my basis.

MEMBER APOSTOLAKIS: Okay.

MR. RADLINSKI: For new reactors, if the certified design a licensee is referring to for their COL included a detailed fire PRA, then it is required by the regulations that they adopt that fire PRA, make it their own, modify it, make it specific for their plant, and carry it on through the life of the plant.

To my knowledge, every certified design so far has had a fire PRA.

MEMBER APOSTOLAKIS: So there will be 805 plants if they use that design. That's what you mean?

MR. RADLINSKI: Well, we won't call them 805 plants because 805, strictly speaking, is for existing plants. It's the standard, okay. But yes.

MEMBER APOSTOLAKIS: The whole idea of --

MR. RADLINSKI: Risk informed, performance-based.

MEMBER APOSTOLAKIS: Yes, yes. That's right.

MR. RADLINSKI: Right.

MEMBER APOSTOLAKIS: That's very good.

MR. RADLINSKI: That is the training.

That is the way it is heading.

MEMBER APOSTOLAKIS: Okay.

MR. RADLINSKI: Okay?

MEMBER APOSTOLAKIS: Thank you.

MR. RADLINSKI: Let's see. We make the same sort of -- provide the same sort of guidance in the updated Reg Guide with respect to the PRA methodologies in that the licensee should submit those to the NRC for review and approval. They should be peer reviewed. And likewise or similarly fire models that are used by licensees should be one of the five or so that the NRC has reviewed and accepted. Otherwise they should submit an alternative for NRC review and approval.

We include references to the NUREG/CR-6850 and also to the draft ANS standard on fire PRA.

MEMBER APOSTOLAKIS: Why are you looking at me?

(Laughter.)

PARTICIPANT: Because you are Mr. PRA.

MR. RADLINSKI: Okay. The last thing, I think, for the Reg Guide is that we added some terms to the glossary. We clarified some other terms. These are terms that have not been clearly defined in the past, have been possibly misused by some licensees.

The new definitions and the clarifications are all based on regulatory requirements, staff positions, and/or common usage. And when I say common usage, I don't use that loosely. It is common usage that is in accordance with regulatory requirements and guidance.

Some of the terms that have been added or clarified include any and all with respect to circuit analyses, emergency control stations, what is a fire protection system versus a fire protection program, mitigation, mitigation of spurious actuations in this case, the term one-at-a-time, as I mentioned before, we are making clear that that does not meet regulations, operator manual actions, what -- we've never had a definition of what is an operator manual action, what constitutes an operator manual action.

Also what are post-fire safe-shutdown circuits, what is a redundant train and redundant system, and what is a success path for post-fire.

MR. WEERAKKODY: You took my job.

MR. RADLINSKI: Oh, I'm sorry.

Yes, by the way, you have to blame me for Sunil not being here on time. It was my fault. I told him one-thirty. I originally thought we were on for one-thirty so it was my fault. I'm sure I had an agenda that said one-thirty.

MEMBER SIEBER: Was it intentional?

(Laughter.)

MR. RADLINSKI: No. He's here for moral support.

MEMBER BONACA: Particularly for the love of magic.

MR. RADLINSKI: Okay. That is it for the Reg Guide updates. Now we will move on to the SRP 9.5.1 and the changes that we made to that.

The biggest change is that the SRP has included the branch technical position or various forms of the branch technical position that was originally prepared after the Browns Ferry fire that provided specific, detailed guidance and criteria for plant fire protection programs.

All of that information, all of that guidance and those criteria are now rolled into the Reg Guide 1.189. A lot of it was already in the Reg Guide. There was a lot of overlap. So we decided we would take it out of the SRP and just include it in the Reg Guide.

And, of course, the Reg Guide is listed as one of the documents that provide the acceptance criteria for the standard review.

We also expanded review guidance for new reactors just as we did in the Reg Guide. The SRP had been updated in 2004, previously rev 4. And it did include some direction, some guidance on new reactors. We just expanded that.

We added a reference to the future SRP section that is going to cover the 805 plants. We provided review guidance for fire modeling and PRA methodologies in licensee submittals. And, again, for non-805 plants. And we felt it was worth having that similar guidance in both the Reg Guide and the SRP because of its importance.

We expanded the review guidance for license renewal applications and also expended the references sections to bring that up to date.

Okay, that was a summary of the items. Now we'll get into a little more detail.

MEMBER BONACA: That section there, an SRP on power up rates.

MR. RADLINSKI: Pardon me?

MEMBER BONACA: You have also a section on power uprates.

MR. RADLINSKI: There is a section on

power uprate that was there in revision 4.

MEMBER BONACA: It was already in revision 4.

MR. RADLINSKI: We changed a few words. It's not hardly worth mentioning.

MEMBER BONACA: No, I think I understand it.

MR. RADLINSKI: Okay. What else to say about the BTP. I think I have already said all of this. Yes, I have. Let's move on.

Okay, the expanded guidance for new reactors, we provided risk insights for new reactor fire protection programs. That is not in the Reg Guide. That is for the reviewers. It is a whole list of aspects of new reactor design, new reactor fire protection programs based on the certified designs that will make them less risky. We felt that that was important for the reviewers to be aware of when they do their reviews as guidance.

We also added guidance, additional guidance with respect to ITAAC and COL applications and the programmatic features of the fire protection program.

We identified review interfaces within the NRC with other branches. We referenced the draft

Reg Guide that is out, 1.45 for COL applications for applicants. And we expanded the guidance for reporting evaluation findings.

We added new references applicable to new reactors and any recent, any current references that had not be included. We added guidance for fire protection systems that provide back up to safety-related systems, primarily for plants with passive post-accident shutdown. At least two of them are relying on or have a design that assumes that the fire protection system will provide a backup supply of water after 72 hours.

We have identified alternative designs that have been accepted by the staff in reviews that have been conducted so far. AP 1000 and also ESBWR have taken exception to certain acceptance criteria for fire protection, particularly in the control room complex. We have accepted those exceptions based on their arguments. So we have added that as guidance for future reviews.

We have also provided guidance for review of fire protection systems protecting areas that don't contain safety-related structures, systems, and components such as on ESBWR we have the diesel generators are not safety related. Even their cable spreading rooms they say are not safety related.

There was an Appendix A that has been replaced. But the old Appendix A was basically a rehash of what is in Reg Guide 1.191 for reactors -- fire protection for reactors that have been shut down, permanently shut down, and decommissioned. So we didn't feel that we needed to have that in the SRP.

We updated the guidance on the use of fire modeling and probabilistic methodologies for non-805 plants, which I mentioned before. And added reference to the new SRP section on 805 plants. I also mentioned that. And the expanded review guidance for license renewal applications.

I think that is it. Yes. This will be your last slide. So any questions?

MEMBER SIEBER: I will perhaps add some general remarks about this review. We asked the staff to give this presentation to us because my review of the Reg Guide showed me that it is a very complex Regulatory Guide. And it is also very lengthy.

The document that was provided is 134 pages in length. If you look at the changes that the staff made, the changes amounted to about a net increase of 16 pages of text, okay. There are 174 references in the Regulatory Guide including 72 references to codes and standards from the NFPA, ANCI, ASTM, IEEE, ASME, Underwriters' Laboratories, I mean there is no shortage of references and no shortage of guidance as to how fire protection should be treated in nuclear power plants.

Eleven regulations in Title 10 apply one way or another to fire protection, including Appendix R. There are 11 Regulatory Guides, 14 NUREGs, four Branch technical positions, five SECY papers, 15 generic letters, 22 information notices, four regulatory issue summaries, eight memoranda, and eight miscellaneous documents like bulletins, inspection reports, and so forth.

If you look at the sum total of the new draft guide 1170 and compare it to Regulatory Guide 1.189, it really consists of an expansion and builds on an existing body of regulations. And so there really isn't too much in there that is new.

But it takes a thorough review of the document to be able to tell what the staff did. And I did that review. And I have reached a conclusion that there is nothing in the changes that the staff is proposing here that is not consistent with the body of regulations to which is applies. And I think that is an important conclusion.

On the other hand, we did yesterday take issue with the definition. We discussed the difference between safety related and important to safety because they mean two different things.

And if you look in the glossary as to what the definition of important to safety is, it is very vague and nebulous. And you can't use the definition to draw up a list of structures, systems, and components that one would identify as important to safety. Or if we all did it, we would all come up with a different list. And so we think that -- we came to the conclusion yesterday that that is an area that the staff ought to attempt to expand upon in their final guide.

Now the part of the process that we are in right now today is that the staff is preparing to issue this draft Regulatory Guide 1170 for public comment. When the public comments are received, they will sit down and resolve each and every one of the public comments and decide whether it ought to be included as a change to the draft guide or not.

After that, they will publish both the comments, their resolution, and a final draft guide.

And we will have an opportunity to review that again should we so choose to do so. And so that is where we stand in the process now.

I have prepared a draft letter for that that follows the recommendation of the subcommittee for those of you who were here yesterday attending that subcommittee. And we will review that probably tomorrow.

So with that, I think the staff has undertaken a large task. I think that they have done it quite well. But the matter is very complex and it takes careful reading to get through it so that one understands where everything -- what the basic documents are where everything came from and why it is in the guide the way it is.

So with that, if there are any comments from members.

MR. BANERJEE: I just have a point which we talked about yesterday which was in establishing sort of what is important to safety, the equipment, the rationale for that selection should be clarified.

MEMBER SIEBER: Yes.

MR. BANERJEE: It is not just expand on it but say why.

MEMBER SIEBER: Right.

MR. BANERJEE: And a second very minor point that if an applicant decides not to use the proved models or whatever which come out of the -- sort of the PRA part of this, that there should be clarification as to what they can do to get their won models clarified. I think that was briefly discussed.

But it wasn't clear as to --

MEMBER SIEBER: Yes, that is actually addressed in the current version of the Regulatory Guide.

MR. BANERJEE: Okay.

MEMBER SIEBER: And in effect, I think we all recall that just recently we reviewed a NUREG report which was the verification and validation of five fire modeling tools from different places. One of them was from NIST. Another one is EPRI's. A third one came from the French. And there is a V&V process associated with that that describes the range through which the model is applicable, where any bias might be, and the extent of uncertainties associated with it.

If a licensee chooses not to use one of these five modeling techniques and develops its own, it has to do the same verification and validation work that the staff did on the five models that are described in that NUREG which for an individual plant that is quite an undertaking. Develop new tools and then do the same kind of verification and validation that would be appropriate for those tools.

So it is not an easy process. It is described. But the staff may want to look at that description to see if it could be made more clear.

MEMBER MAYNARD: I think the staff has done a good job of pulling together a number of things from Branch technical positions, generic letters, and other things into one document. And I think that is important to do that.

And I think that it is time to get it sent out for public comment. I'm in agreement with that. I think there will be a lot of public comments on it. I think there are going to be a number of issues to resolve and to identify. But I think this is the appropriate mechanism to get it out and get those comments.

MEMBER SIEBER: It is quite an undertaking to do this but this has really been in development for 30 years.

MEMBER SHACK: It's time to go.

MEMBER SIEBER: Okay, no further questions or comments, Mr. Chairman we finished early.

MEMBER SHACK: Despite the fact that we ran over and we had a fire alarm, you got us in here.

MEMBER MAYNARD: I'd like to point out my agenda says 11:45 was when this ended.

MEMBER SHACK: Well, close enough.

MEMBER MAYNARD: I do applaud the effort to get it done.

MEMBER SIEBER: So I thank the staff for their work and their presentation to us. And we appreciate it. Thank you.

MEMBER SHACK: And again, we will recess for lunch. And we will back at one-thirty.

(Whereupon, the foregoing matter went off the record at 11:51 a.m. to be reconvened in the afternoon.)

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

1:34 p.m.

CHAIRMAN WALLIS: Please come back into session.

We will now take up the next item on the agenda, the draft final rule to risk inform, 10 CFR 5046. My colleague Bill Shack will lead us through this one.

DR. SHACK: And we reviewed the latest proposed version of the draft final risk informed 10 CFR 5046 at a subcommittee meeting yesterday. The biggest difference in the rule that's now before us with the one that we reviewed some time ago is a change in the risk informed change process, that is, how we control the changes in risk that can result from this enabling rule.

As it has been pointed out before, changing this rule itself will not change the risk status of anything, but it will permit licensees to make changes and the change control process is what controls those changes in risk.

Some of the other issues that came up yesterday were from the BWR Owners Group, who disagree with the selection of the transition break size for BWRs as it's currently proposed in the rule and have essentially a proposal of their own for a different, somewhat smaller break size.

And we also heard about some discovery of indications, especially in the surge line nozzle at the bottom of the pressurizer at Wolf Creek, and the staff said yesterday that they were revisiting the seismic portion of the technical basis to see if it will affect it.

That's not going to be covered in today's meetings as I understand it.

And I'll turn it over to Mr. Dudley from the NRR to begin the presentation from the staff.

MR. DUDLEY: Good afternoon. I'm Richard Dudley. I'm the rulemaking project manager for the 5046(a) risk informed ECCS rule.

I'm going to have a really very short introduction because yesterday it took over an hour to get through it.

We're here today to request an ACRS letter on the final rule. I'm going to change the request a little bit from what we said yesterday at the subcommittee meeting. We seek an ACRS review of the issues related to 5046(a), the final rule. If the ACRS is content to write a letter on the entire rule, we would appreciate that. The potential impact of the pipe cracking indications at Wolf Creek have caused us to determine to review our position on the seismic analysis associated with the PWR TDS, but we don't think it's likely that -- we think it is likely that whatever we do to mitigate this cracking phenomenon for operating reactors will also make it adequate for the purposes of 5046(a). We think that's likely what our review will conclude, but we believe we'll commit to inform the ACRS how the Wolf Creek review -- what it concludes, and we'll --

CHAIRMAN WALLIS: Well, could I summarize then? If there are no significant changes as a result of this Wolf Creek review and you don't come back to us, this is the last time we get to write a letter before the Commission makes a final decision on the rule.

MR. DUDLEY: That would be correct. If there were significant changes to the rule as a result of Wolf Creek, we would certainly be back, and if you have any issues associated with what you heard yesterday and you wish us to come back, then we will be back.

DR. APOSTOLAKIS: But how does that relate to the first bullet? You're saying you seek a letter, review the issues. That means without recommending to the Commission whether the rule should be approved or not?

MR. DUDLEY: A recommendation, we would seek a recommendation.

DR. APOSTOLAKIS: You said that you changed your request. From what to what?

MR. DUDLEY: Yesterday we were here with a partial request and a promise to come back to you when we completed the Wolf Creek review. today we're thinking that it's likely that our Wolf Creek evaluation will not cause any impacts on the rule, and if you are comfortable with what we presented to you yesterday, we would not come back to you unless there was something significant that came out of the Wolf Creek review. That's the difference.

So we have a shortage into today. Hopefully, we can get through it. First Gary Hammer will talk about the BWR TBS, and then I think probably the most important discussion, Steve Dinsmore will talk a little more about the risk analysis, the risk informed evaluation program and the operational requirements in the 5046(a) final rule.

MR. HAMMER: Yes, hello. I'm Gary Hammer, and we've spent a good portion of the last couple of years working on the transition break size selection using certain guidance and certain goals in mind, and what we wanted to do was select a transition break size that would be somewhat conservative. We wanted to address things that we thought were uncertainties, things that we needed to account for other than the expert elicitation, which we used as a starting point.

And we had some guidance from the Commission early on that we were supposed to base it in the general neighborhood of one times ten to the minus fifth per reactor year frequency of occurrence.

We did make adjustments to account for uncertainties and sensitivities. We did make some other considerations that accounted for or where the elicitation did not account for failure mechanisms, not that they couldn't consider, such as seismic loads and active LOCAs, large load drops, thing like that that tended to be somewhat plant specific and very hard for them to estimate.

We did consider the configurations which exist in various plants as best we could to look at the actual pipe sizes and how they're connected to the main loops and what that generally would tell us, and ultimately we hope that the size that we select will give us some regulatory stability so that we won't have to impose a change to the TBS at some future point so that they would have to make changes to what they've done in order to implement this rule.

And I apologize for the slide title. It says BWR TBS selection. Actually that's a more general characterization for what we did for BWRs and PWRs, and --

DR. BANERJEE: May I ask a question?

MR. HAMMER: Yes.

DR. BANERJEE: Yesterday there was a discussion about having potentially NRC staff coming back to us with consideration of the materials aspects of this. I seem to remember this discussion went on, and then the BWR people, in fact, said that they wanted to come back when there was some meeting with the materials subcommittee.

But today we are being told that we need to make sort of whatever we need to put into the letter right away and not wait for this material subcommittee meeting to occur; is that correct? Are we going to get a chance to revisit this in detail or are you asking for an opinion right now?

MR. HAMMER: The meeting I believe you're discussing on materials and that sort of thing would be a meeting on the resolution of the comments on the expert elicitation.

DR. BANERJEE: Right.

MR. HAMMER: By the Office of Research. They have concluded that after resolving the comments, that there are no changes to the curbs, and so we are working with that, with the conclusions in their report. But the meeting, as I understand it, would have been to discuss with Research how they resolved the public comments on the expert elicitation analysis.

DR. BANERJEE: But we can't take the results of that into account in writing our letter? Do you want the letter before we have that meeting? That's what I'm confused about.

DR. APOSTOLAKIS: And if we write the letter, why have the meeting at all?

DR. BANERJEE: Yeah, right.

DR. ARMIJO: What use is it? We just go with what we know now or what we don't know.

DR. BANERJEE: Well, I'm just confused. I need clarification. You're now visiting this TBS selection, and we haven't had this meeting with regard to how one arrived at this TBS to begin with.

MR. DUDLEY: I guess there were several other meetings associated with it. The TBS in the final rule is identical to that in the proposed rule, and it was discussed in a number of previous meetings. I'm sorry. You were not with the committee then.

DR. BANERJEE: Yes, but yesterday --

DR. ARMIJO: But several of us weren't.

DR. BANERJEE: Yeah. Many of use weren't, but --

MR. DUDLEY: Yes, yes.

DR. BANERJEE: -- yesterday there was a sense at least that I had that we were going to have a meeting about this TBS thing. If I'm wrong, maybe the transcript --

DR. SHACK: No, we were planning to have a meeting, but --

MR. DUDLEY: The meeting was on the resolution of comments on the expert elicitation. I don't believe -- we did not believe we committed to a meeting on the TBS. If you wish to have such a meeting, then if you tell us, you certainly will.

DR. APOSTOLAKIS: The problem is that the

BWR Owners Group presenters skipped several of their slides because they were materials oriented.

DR. BANERJEE: Exactly, yeah.

DR. APOSTOLAKIS: You know, what you're saying, Richard, is that the main conclusions of the NUREG on expert opinion elicitation are not expected to change, but at least it's probably the staff's view and this committee will not have had the opportunity to weigh the argument of the owners group against the staff's view.

So this committee may decide that the results should change. I don't know, in which case now we're putting the cart ahead of the horse here. We're expected to make a recommendation on the ultimate rule, but without all of the information regarding the expert opinion elicitation.

MR. THORNSBURY: Maybe I can help. This is Eric Thornsbury from the staff.

Sanjoy, the staff is planning on coming in to talk about the final NUREG that has the expert elicitation in it. That was that meeting. And true, that what they're talking about now draws directly on that, the results from that report, which we won't see until after we issue the letter from this meeting, if we do that like they're asking.

However, it's also, I think, if I remember correctly from yesterday, the BWR Owners Group didn't argue with the conclusions from the elicitation. It was how it got from there to the selection of the TBS.

So their --

DR. APOSTOLAKIS: That's true.

MR. THORNSBURY: -- objection was not with what's in the report. It's how it went from there to the selection. That report stands as it is. It's not going to change, and I don't think anybody objects to it.

PARTICIPANT: Let them speak for themselves.

DR. BANERJEE: Of course, they should speak for themselves, but one of the issues that I recall from yesterday is whether adequate credit had been given for chemistry changes and hydrogen treatment and all of these other things in this expert elicitation and exactly how was it structured.

So I think we need to know this stuff.

CHAIRMAN WALLIS: And not only that, but the consequences of BWR Owners Group suggested that if one did take credit for this and if it resulted in a smaller TBS, this would have a much more significant effect on BWRs. So the consequences would be much more profound.

MR. DUDLEY: Staff would clearly support a meeting or meetings at the committee's wish. If you want to combine an expert elicitation comment meeting perhaps with some other issues, we will certainly support that.

DR. SHACK: Well, let's move ahead with the presentation.

DR. APOSTOLAKIS: Let me understand though. Eric, when does the staff plan to come here and talk to us about the resolution of the --

MR. THORNSBURY: I do not know. It was initially planned we were going to do it all together, but they're still working on wrapping up the comments. In the spring --

DR. APOSTOLAKIS: In December?

MR. THORNSBURY: They have said the spring of next year.

DR. APOSTOLAKIS: The spring?

MR. THORNSBURY: That's what they've said.

PARTICIPANT: What good is it? What value is it?

MR. THORNSBURY: It was our office's understanding that that meeting was going to take place, you know, in November. That was our understanding, and obviously we haven't had good communications with the other office.

DR. APOSTOLAKIS: If it's December, I think, you know, it's an important piece of information because one month in the biggest scheme of things is not a big deal, but spring I don't think makes sense.

DR. SHACK: Well, we'll have to move ahead and we'll decide as we write our letter just where we end up on this.

MR. DUDLEY: Okay. Thank you.

MR. HAMMER: Okay. So that was more or less the selection process.

So if you go through that, what we ended up with was starting with the ten to the minus fifth frequency, and if you consider as indicated in the two sub-bullets there, a 95th percentile estimate, which gives you some estimation of uncertainty or accounting for some uncertainty, and if you consider both the geometric and arithmetic mean aggregations of the data, and there are different ways to do that, and so we looked at sensitivities of doing that different ways, you end up with a size range as indicated there of approximately 13 inches to 20 inches in diameter.

And here, again, this is using the BWR as the example.

So then we looked at --

DR. APOSTOLAKIS: Well, you remember yesterday the issue came up whether the cutoff frequency is supposed to be the mean or something else, and I looked at the SRM from 2003. I guess they imply that it should be some high percentile. They give an example, 95 percent probability with a 95 percent confidence. So you really have to go up there.

MR. HAMMER: Yeah, that's true, and the elicitation, the data reduction from the elicitation gave us curves for all of those different size, and --

DR. APOSTOLAKIS: It's important though to bear in mind, as you say, you know, the 95th percentile and the arithmetic versus geometric, as I recall, there was also an adjustment. I mean, these numbers are not derived directly from the expert opinions of the experts. There were --

DR. ARMIJO: There's a lot of treatment of the data between the expert elicitation and what we're seeing. They've added a lot of stuff.

DR. APOSTOLAKIS: No, but there's an additional thing that is buried in the report that for a certain region or range of expert opinions, the analysts here at the NRC changed those estimates using arguments from cognitive psychology that people can't underestimate things and so on.

It's not like you had five experts that said three, five, six, and seven, and they take the geometric mean or the arithmetic mean as presented here. The numbers three and five are the result of the adjustment by the staff. The experts may have given two and one.

So this is important to bear in mind that there was some manipulation of the results, out in the open. I mean the word "manipulation" is not right.

DR. BANERJEE: Has this expert elicitation been gone over in detail in front of this committee?

DR. APOSTOLAKIS: Yes, yes.

DR. BANERJEE: So all of this stuff came out at that point?

DR. APOSTOLAKIS: Yeah, and it's also in

the report. I mean, they didn't hide anything. They were very open about what they did and why they did.

The arithmetic mean that you see, for example was done as a result of a request of the committee. They only had the geometric mean.

DR. ARMIJO: You know, I think I remember from yesterday that the final answer for the BWR pipe cracking, the benefits or the reduction in frequency, LOCA frequency turned out to be something like 20 after all was said and done, a factor of 20 reduction in frequency.

And I got hold of that big elicitation report, and I was panicking and looking through it, and I found a curve where somebody put together I guess it's closer to the raw data, and they claimed it was a factor of 60.

Now, the Owners Group mentioned yesterday it was a factor of 33. I don't know what the right factor is, but I would tend to think it would be more towards a larger than the smaller. So we haven't had any chance to really look at that, to say, hey, you know, is what the -- the elicitation is the basis for the rule, for at least the materials part of the rule, and we haven't looked at it. At least I haven't looked at it.

DR. APOSTOLAKIS: I thought they showed us yesterday the curves, didn't they?

DR. ARMIJO: They did, the curves, but there's a lot of stuff that has gone into building those curves.

DR. APOSTOLAKIS: Well, yeah.

CHAIRMAN WALLIS: Well, maybe the rules should say there should be a transition break size without specifying what it should be.

DR. BANERJEE: Why should there be a transition break size? It's not an on-off phenomenon. Is it a bang-bang thing?

CHAIRMAN WALLIS: No, this is for convenience in making decisions. You split the break size into two parts, but where you draw the line may depend on the evidence which is continually changing. That is part of the difficulty.

DR. SHACK: Part of the things you're seeking to avoid is having that continuing to change.

CHAIRMAN WALLIS: But it is continuing to change.

DR. APOSTOLAKIS: That's why the staff is conservative in its choice.

CHAIRMAN WALLIS: Which I think they are.

DR. APOSTOLAKIS: Because you want to avoid this.

DR. BANERJEE: But you have already discussed and accepted this concept of a transition break size? This committee has agreed that this is a good way to go?

DR. APOSTOLAKIS: Yes, in a letter.

DR. SIEBER: Yes, we have.

DR. SHACK: But we have not approved this draft final rule.

DR. SIEBER: Right.

CHAIRMAN WALLIS: But we don't have to be committed to that if we don't like it now. I'm not quite sure what we said about whether it's a good concept or not. We may have said it's a workable concept.

DR. SHACK: No, we approved the approach.

DR. ARMIJO: Where is Mario?

DR. APOSTOLAKIS: No, we did approve the concept. There's no question about it.

DR. SHACK: There is no question about it. That's beyond debate.

DR. APOSTOLAKIS: The statement I remember is that, you know, if you have defense in depth or breaks above the DBS, then even a lower value could be supported. That's a sentence from that.

So we were arguing about the value, not the concept, but what is it that bothers you about it Sanjoy?

DR. BANERJEE: It seems very sudden the transition, you know. I'd like to see things happen a little more realistically and gradually. Obviously there's a change in probability, you know. So what you're doing is you're taking some sort of a curve like this and putting a cliff there.

DR. APOSTOLAKIS: And they are doing it --

DR. BANERJEE: And then there's a completely different set of rules on one side and a different set of rules on the other side, you know.

Now, I think within the risk informed framework we've got the best estimate plus uncertainties already existing, which allows you to handle a realistic curve.

DR. APOSTOLAKIS: No, because it forces you to assume loss of off-site power.

CHAIRMAN WALLIS: But that's a separate issue. You could handle that.

DR. APOSTOLAKIS: What's a separate? I mean, that's what they're doing. They're eliminating that requirement.

CHAIRMAN WALLIS: But you could do that without changing the rule.

DR. APOSTOLAKIS: Really?

CHAIRMAN WALLIS: Without changing the rule dramatically.

DR. SHACK: Let's hold this discussion for later as we discuss what we want to write about this. Let's hear the staff's presentation on the rule that they've written.

CHAIRMAN WALLIS: Thank you.

MR. HAMMER: Okay. So let's see. Then we attempted to apply that size range to what we see in the plant. So we looked at the different size pipes and the reason you kind of look at the sizes of the pipes themselves is that, you know, that tends to be a likely way to get a break of that size, is to break the pipe completely, and since welds tend to be oriented circumferentially and that's where you generally see the degradation that does occur, so you have attached feedwater and residual heat removal lines inside containment, and typical BWRs that are 18 to 24 inches nominal diameter, and there you see those inside dimensions, which gets you close to that size range, maybe a couple of inches larger, and breaks larger than these would require complete failure of the large recirculation pipe, which, you know, gives you a double ended type of configuration, and you have a significantly lower frequency of occurrence of that.

And so that started to look to us like it was a reasonable demarcation of where you would select the size.

DR. APOSTOLAKIS: So the theory you are using is not just the expert opinion result plus some margin. You're also looking at the more or less natural grouping of the pipe sizes in the plant.

MR. HAMMER: Correct.

DR. APOSTOLAKIS: You're saying if we go up to here, then the next level will be significantly larger, which has a significantly lower frequency. So it's the combination of the two.

MR. HAMMER: Right.

DR. KRESS: Can I infer from this that a 16 inch ID BWR pipe would be an acceptable transition break size for BWRs to use?

MR. HAMMER: Yes, yes. It would be dependent upon what the pipe size was at the particular plant. That would correspond to an 18 inch nominal --

DR. KRESS: That range you have there is for the various plates.

MR. HAMMER: Right. That's right.

DR. KRESS: But the smallest one is 16, and they'd like to come in and say, "I want to use 16 for my TBS." That --

MR. DUDLEY: It is also the difference between inside and outside diameter.

DR. KRESS: Yeah, I'm looking at the ID though.

MR. DUDLEY: The ID, yeah.

DR. KRESS: Because that's the leak size.

DR. SHACK: The Owners Group proposal is more like a 14 inch ID.

MR. HAMMER: Right.

DR. KRESS: ID. Okay.

DR. SHACK: A 16 inch Schedule 80 pipe which roughly is like a 14 inch --

DR. KRESS: I was remembering the 16, but it's an ID.

DR. SHACK: That's a good way to present it. The 16 sticks in your mind.

DR. APOSTOLAKIS: The expert results are

all in terms of the internal diameter.

DR. APOSTOLAKIS: Right.

DR. KRESS: Yeah.

DR. APOSTOLAKIS: So why are they giving us that?

DR. KRESS: Yeah, that's crazy. You're right.

DR. APOSTOLAKIS: Just to confuse us?

DR. KRESS: Just to confuse you. It confused me. I was thinking --

DR. APOSTOLAKIS: So it's really not 16. It's 14.

DR. SHACK: It's 14, yes.

DR. KRESS: But from there, what I assume is that 14 is not acceptable.

MR. HAMMER: Well, especially the way they wanted to apply it, which was just to make it constant across the whole fleet of BWRs and not regard what size the pipes actually were.

DR. APOSTOLAKIS: That's a big difference.

DR. KRESS: Why would it matter because those plants that have 20 inch ID are going to use 20 inch? It shouldn't matter if it was across the whole fleet.

DR. BANERJEE: But these can be holes in

the resurf, pipe as well with that flow area, right?

DR. ARMIJO: Yeah, it's a cross-sectional area issue, right? I think that's what was presented yesterday.

DR. KRESS: Yeah, it's a cross-sectional area that you're worried about.

DR. ARMIJO: So that's the size that's the transition break size.

MR. HAMMER: That's right, yeah.

DR. ARMIJO: Whether it's a pipe or whether it's a blowout on one side of --

MR. HAMMER: That's right. This is only a size. I mean, you still have to determine where the location was.

DR. SHACK: The most severe break is not going to be the break of this pipe in all likelihood.

MR. HAMMER: Right.

DR. SHACK: It's going to be a break of this size at another location.

CHAIRMAN WALLIS: Such as a manhole.

DR. MAYNARD: You may be addressing this in the comments later, but I thought the Owners Group had a good point on we're saying the largest of the feedwater and residual heat removal lines, although they are different sizes, and the RHR line is actually a more severe -- a smaller line, but can be a more severe accident.

I'd like to have the staff's perspective on why you have to take the largest attached line and apply that accident to different locations. I don't know if you're going to do it now or if you're going to do it later, but --

MR. HAMMER: I'll take a stab at it. I mean, we have a thermal hydraulics guy here also who can give you a little perspective on that, but in selecting the size and keying it into the attached pipe, I mean, it's just a logical thing from a mechanical point of view. It has nothing too much to do with thermal hydraulics.

You know, realizing that that might be the way that you would get this break to occur, and let's go ahead and try to encompass that situation should it occur.

Now, where you locate it and put that location of that size break at a limiting location, you could look at that as another level of conservatism and addressing some uncertainty, you know, just how this break would occur.

CHAIRMAN WALLIS: I'd like to go back to

Sanjoy's question about where this transition break size came from. I've been reading the letters we wrote on this before. The impression given is that this came from somewhere, which as the Commission simply said, "Consider this transition break size," and there wasn't some argument about why this was the appropriate thing to do. It was just a concept to be evaluated.

DR. APOSTOLAKIS: No. The argument was the frequency of contribution of LOCAs to the core damage frequency in PRAs.

CHAIRMAN WALLIS: That's right. There was an argument, but this was suggested as the solution, you know, as the design solution in the rule to a problem about these probabilities in the PRAs, and so on.

DR. APOSTOLAKIS: I don't understand. There was no problem.

CHAIRMAN WALLIS: It was taken as a given that the staff was to evaluate a TBS. This was never sort of subject to question and evaluation.

DR. APOSTOLAKIS: I believe this agency traditionally has not looked at initiators of frequency less than ten to the minus five; is that correct?

CHAIRMAN WALLIS: Oh, I understand that, George. I'm just saying where did TBS come from. That's what I'm trying to understand.

DR. APOSTOLAKIS: That's where it came from.

CHAIRMAN WALLIS: In response to --

DR. APOSTOLAKIS: And they said, "So whey are you looking at the largest LOCA since now you have a frequency?"

And you don't look at events with frequency less than that anywhere else. Why --

CHAIRMAN WALLIS: All right. You're giving me the why, but where did it come from?

DR. BANERJEE: Was it an order?

DR. APOSTOLAKIS: It's a policy issue of ten to the minus five. You don't look --

CHAIRMAN WALLIS: The policy issue that came from the Commission and, therefore, consider TBS because of this --

DR. APOSTOLAKIS: But the policy issue was not developed because of this. It has been around for 40 years.

CHAIRMAN WALLIS: But you could have done it in a continuous way as Sanjoy suggests.

DR. APOSTOLAKIS: How? I mean, you have a big problem selecting one.

DR. SHACK: Let's rewrite the rule later and let the staff finish their presentation.

CHAIRMAN WALLIS: We're trying to answer Sanjoy's -- maybe we can do it later on.

MR. HAMMER: So actually that was about all I had to present.

We did get some comments on the rule from the BWR owners group. We had comments from Dr. Hochreiter at Pennsylvania State University. Dr. Hochreiter's comments were that we weren't conservative enough. He came up with some curves that showed that what he thought the frequencies were quite a bit higher. We didn't agree with that, and the BWR Owners Group thought we could make the TBS a little smaller for them.

The PWR Owners Group also had a general comment that, well, if we're using attached piping, why don't we use the attached piping on the cold leg for a cold leg break. Use the attached piping on the hot leg for a hot leg break. We thought that might be splitting it a little too finely. We just wanted to define one TBS, and so we had what we thought was a rationale for saying that was nonpersuasive.

So that's basically what we did on the TBS slate.

DR. APOSTOLAKIS: I believe Dr. Hochreiter came before this committee once. Was it in this context or was it difference in depth?

DR. SHACK: It was this context.

DR. APOSTOLAKIS: This context?

CHAIRMAN WALLIS: But he had a lot of other arguments, too.

DR. SIEBER: Database extends beyond --

PARTICIPANT: Jack, you need to get up close.

DR. KRESS: He can't hear you.

DR. SIEBER: His database extends beyond reactor plants, I think.

CHAIRMAN WALLIS: That's right. That's part of the problem. Were these typical of the reactor type plants?

DR. SHACK: At least reactor coolant piping systems.

DR. SIEBER: Right.

DR. APOSTOLAKIS: And so what?

DR. SHACK: It's just that it's a different database

CHAIRMAN WALLIS: It's a different

database. It doesn't apply to stainless steel pipes of large diameters.

DR. SHACK: If you're looking at this from a statistical point of view, your statistics will be different depending on which database you decide to look at, and you have to decide whether it's relevant or not.

DR. APOSTOLAKIS: The five experts were unaware of this?

DR. SHACK: No. I believe the experts thought they were dealing with the most relevant database.

DR. APOSTOLAKIS: Yeah, it was a judgment.

DR. SHACK: Yes. The reason why I'm saying these things, because we keep putting them down as if they were children that didn't know what they were doing, and this guy comes from Pennsylvania state that knows.

I'm sorry, but there was a lot of work that these guys put into this.

DR. ARMIJO: Yeah, I hope I didn't give you that impression because I know two of those people, and they're excellent people. So -- that were on that committee, but that doesn't mean I agree with their conclusions.

DR. APOSTOLAKIS: Absolutely. You can disagree, of course.

DR. BANERJEE: We have a sixth expert here.

(Laughter.)

DR. APOSTOLAKIS: Well, we have a transcript here and if we just say he had a different database, I mean, somebody who reads it says, "Oh, gee, well, these five guys, they spent" --

DR. SHACK: Let's just to be more accurate since we're on the transcript, I mean, most of his failures are erosion-corrosion, flow assisted corrosion failures, which are not really a problem in these reactor coolant piping systems.

DR. BANERJEE: Now, didn't we hear about a French stainless steel elbow which was eroding in --

DR. SHACK: Japanese.

DR. BANERJEE: Oh, was it a Japanese? And that was sort of strange. How do you explain that?

DR. KRESS: They explained that it had droplets that were impinging. It wasn't flow accelerating.

DR. ARMIJO: Like carryover in turbine.

DR. KRESS: Yeah. So it was the nature of the steel.

DR. BANERJEE: It was a stainless steel erosion problem, right?

CHAIRMAN WALLIS: That was the suggested explanation.

DR. KRESS: It was suggested, and they had --

DR. ARMIJO: We don't know that.

DR. KRESS: -- reasons to back it up, but it wasn't for sure.

DR. BANERJEE: I just -- anyway, let's carry on.

MR. DUDLEY: Our next speaker will be Steve Dinsmore on probabilistic risk analysis if we're ready to go on.

MR. DINSMORE: Yes, hello. My name is Stephen Dinsmore. I'm a senior risk and reliability analyst at NRR.

And my presentation is a little different. As you all know, we put out a proposed rule for comment, I guess, November of last year, and we got a substantial number of comments back, and my presentation is going to go through the major public comments that dealt with the risk informed process of the whole rulemaking.

So I'm going to present a brief summary of each major comment that we received, and the resolution of some of these comments caused us to make changes to the rule. The resolution of others did not cause us to make changes, and any changes to the rule made to resolve the comments are identified in the slides.

I apologize to everybody yesterday. I didn't redo this. So you might have heard some of this before.

The major comments we got related to the scope of the facility changes requiring a risk evaluation, identification of changes that require prior staff review and approval, attracting risk increases, periodic PRA updating and reporting, acceptance criteria on the amount by which risk increases, and operational restrictions in maintaining mitigation.

Now, from these, the first two, the scope of the changes and identification of changes that called for prior staff review, and the last one, operational restrictions, the industries indicated that if we put the rule out without changing these sections, that it would not be useful to them.

And since this is a voluntary rule, it

behooved us to go back and try to address the concerns that they had while, of course, maintaining our commitment to safety, to change the rule to make it less burdensome and more useful.

So I'm going to go through each one of these comments at a time. So the first comment. The proposed rule said a risk evaluation of all changes is required prior to implementing the change.

Now, the comment that came back from pretty much everybody was this does not credit current change control processes and is unnecessarily burdensome.

The final rule that we put out requires a risk evaluation prior to implementing potentially risk significant changes and a periodic risk evaluation is required to assist the cumulative effect of all changes.

Now, how we got from what we had to where we are now was we decided that the best goal that we had would be to eliminate all redundant regulatory control where possible and to minimize any additional requirements to the extent possible. And I'll explain this with this slide coming up.

Up here you see a start sign. We learned.

DR. ARMIJO: We made a contribution here, didn't we?

MR. DINSMORE: So you start out by saying we've got to change, and you say is the change governed by change control regulations, and if it is, then --

DR. APOSTOLAKIS: It is very responsive.

(Laughter.)

MR. DINSMORE: -- if it is, then the question is, well, do you have to make a submittal. And if you don't have to make a submittal, this chart says you just simply implement it.

And the reason for that is the change can pull the change control processes that are used by licensees to decide whether they can make the change on their own or whether they have to make a submittal. We believe they're pretty robust.

In other words, it's very doubtful that a licensee would be able to use these processes and make a change without requiring NRC approval, which would be a risk significant change.

DR. KRESS: No, if they go that route, then they don't have to follow this other rule that they're going to track all of the deltas? I mean, that's not a delta you can add in because it's mostly qualitative.

MR. DINSMORE: The route which goes over to "no"?

DR. KRESS: Yeah, the "no" route.

MR. DINSMORE: The "no" route, what would eventually happen is if the change nevertheless did affect something that might affect the PRA, when they do the periodic PRA update, they would have to include that change in the update.

DR. KRESS: The reason they can go that route is because the risk implications are so small that you don't believe them.

MR. DINSMORE: Right. We don't --

DR. KRESS: So it seems like that should be exempted from the continuous tracking of the changes in the delta, but you know, that was just my opinion.

MR. DINSMORE: Yeah, that adds a little extra complicated twist. It was easier just to say, well, periodically you just update to all changes, and one of the reasons that we believe that that implement green boxes is pretty benign is they have criteria in these guidelines or the regulations that say maintains an acceptable level of safety, does not reduce the effectiveness of equipment or the procedures and so on and so forth.

Now, if they actually do have to make a submittal, then they need to do a risk informed evaluation, and again, many of these are probably going to be relatively simple and straightforward. We anticipate that, and then they would make a submittal.

Now, if the change was not governed by change control regulations, there is a rule out there which has identified equipment, safety -- let's see, systems, structures and components that are relevant to safety, and that's the maintenance rule. Now, the maintenance rule didn't really care about what was under regulation and what was not under regulation. It's a risk informed type process, and they went through and identified all of this equipment that had some nexus to safety.

And so we said, well, even if it's not governed by the regulations, we have this list of equipment out here that could be safety significant. So if this change you're going to make affects some of that or if the change you're going to make doesn't affect any of that equipment either, then you can go ahead and implement it because it's very unlikely to have any effect on risk.

But if it does affect some of that equipment, then you would do a risk informed evaluation of it, and the results of that evaluation you need to compare to the acceptance criteria and the rule. And the acceptance criteria in the rule is the total increases in CDF and LERF are small, and if it doesn't meet that criteria, you either would not implement it or you'd have to bundle it with other changes or wait to some point in time where you have enough --

DR. APOSTOLAKIS: These other changes now can be unrelated to 5046(a)

MR. DINSMORE: Yes, sir. They would be just whatever. It could be anything.

DR. SHACK: When I looked at this again last night, what struck my mind is you're going to allow them to make changes that result in delta DCS between ten to the minus six and ten to the minus five without any staff review.

Now, in the 1174, if we had a delta CDF that big, we'd be sitting here checking to see whether the total CDF was ten to the minus four including shutdown risk, seismic, the whole kit and caboodle.

Over here on the other side, if I have a

5059 thing that doesn't meet my minimal change in risk, I'm going to do a risk informed evaluation and submit it to the staff. So I've probably got a two order of magnitude differences in stuff that I'm submitted for staff review and stuff that the licensees just goes off and does on his own.

MR. DINSMORE: Well, the first point is that that small -- they might not have a ten to the minus five left. They might have some -- I mean, that small is the cumulative small.

MR. TSCHILTZ: Steve, this is Mike Tschiltz. Let me comment on that.

I think you know, when we said previously that we don't expect anything significant to get through on the left-hand side, that means that anything significant is going to be coming for staff review.

There to the right-hand side, those are changes right now that can be made without any NRC involvement.

DR. SHACK: No, but even after he goes through his risk informed evaluation, he finds out that it involves --

MR. TSCHILTZ: I understood but the likelihood of those being risk significant to the degree you're talking is very, very unlikely because of the fact that they were not safety systems. They may be reflected in the PRA. But the chance of them having that big of an impact on risk is very small. And I think what Steve was trying to point out there is there is an analogy like I gave yesterday about the checkbook accounting. You can only make so many changes to increase risk so much before you have to make offsetting changes that reduce the risk.

DR. SHACK: But why when I get down to the very small criterion I don't meeting? Why do I then go over and make a submittal to the staff?

MR. DINSMORE: Well, as I said, we tried to keep the additional requirements to a minimum. We could request that.

DR. SHACK: But again, not meeting the very small requirement, you know, okay, it's an order of magnitude difference between the change I can make on the left and on the right without staff review.

I've burned up my delta CDF in there.

MR. RUBIN: This is Mark Rubin.

I could supplement what Mr. Tschiltz said, which was right on point, is the fact that there are many elements of the plant that can have various impacts on risk that are far beyond the scope of regulatory requirements and regulatory oversight.

And as Mr. Tschiltz said, right now they're free to make any of these changes because there are no regulatory requirements. We don't have a, quote, PRA rule with PRA limits for the plant that are in the legal basis of the license for the plant. The best example I could give you is that a plant might decide to put in a black start gas turbine. You know, it's a real useful item. They may or may not put it into their PRA, but it's clearly a beneficial item or they could decide it's working so poorly they're going to take it out.

So these are non-regulated areas, and we have no current requirements that require everything outside of the regulatory safety scope be assessed if there's no reporting requirement or no approval of submittal requirement on the books.

Tech specs, yes. Thank you, sir. That's a good example.

MR. DINSMORE: And the last point is that you're right. They could get to there and make it ten to the minus five change and not tell us. However, it would be reported under this meets very small criteria, and every two operating cycles they'll send us a list of stuff, and that's partially the reason that that was eventually inserted because we were pretty sure that they wouldn't be able to make very large changes, but we wanted that little extra check at the end to make sure we could go back and, oh, you know, these were not working out like we expect. We might have to inspect them.

DR. APOSTOLAKIS: This bundling thing bothers me, and I think you have a slide later where you say that the total delta CDF or the total LERF should be small.

MR. DINSMORE: Right.

DR. APOSTOLAKIS: I really think we ought to go back to 1174 and find where it states explicitly what delta CDF is to be compared with ten to the minus five. My recollection is that it should be the individual change, not the total.

And as I said yesterday, the guide says somewhere that the staff should consider the total, but it doesn't tell you what to do. In other words, I suspect if you start approaching the goal of ten to the minus four and exceeding it, the staff will consider and say, "Wait a minute now. You're really overdoing it."

But this is a major change it seems to me, and the Commission of SRM, as I look at it again, it says that any proposed changes should be risk informed and consistent with the principles of the regulatory guide 1174. So with the principals you are consistent because you are considering the defense in depth and safety margins and so on.

But this acceptance limit of ten to the minus five for CDF and six for LERF, I think you're turning it upside down, and I really think we ought to consider that, and as I said yesterday, maybe it's more appropriate to look at it when we revised 1174 again, but this is certainly different.

MR. DINSMORE: Well, I can explain to some extent. Again, the 1174 is somewhat unclear about what you're going to compare that criteria to, and the concern about taking changes and splitting them up over time such that each one passes the acceptance criteria, but that the cumulative set will not pass, would not, is a concern that we've had the whole time, and in all of the individual regulatory guides, there is guidance on keeping track of that.

So each individual regulatory guide that has come out to date has cautions in there and has guidelines on how you do that. And, again, we tried to put that standard process in here.

DR. SHACK: But I think when you first came here and discussed this the last time, the understanding was that for each sort of major change in risk informed regulation you capped the increase at ten to the minus five.

MR. DINSMORE: For each one of these applications, yes.

DR. SHACK: For each one of those applications. Now, this is a different one. This caps it at delta ten to the minus five for everything.

DR. APOSTOLAKIS: And your interpretation, Steve, you say that, you know, it wasn't clear and now we're clarifying it and so on, but if you do that, the ten to the minus five did not come down from a mountain. When we approved it, we had in mind individual changes. It would have been something else if it was a problem, right?

In other words, you can't take the number and then change what you compare.

DR. SHACK: It's one-tenth of your goal. I mean, I could justify the number, but --

DR. APOSTOLAKIS: No, no, no, no, no.

DR. SHACK: You know, it seems to me that it is certainly an interpretation of 1174 that's not obvious, and I can't find anything in this rule that says you do it either. So I'm not sure. This is a staff interpretation.

MR. DINSMORE: You mean the total?

DR. SHACK: The total.

DR. APOSTOLAKIS: No, the rule say that --

MR. DINSMORE: The rule says total.

DR. SHACK: It doesn't say ten to the minus five. At least I couldn't find it last night.

MR. DINSMORE: Small. It says small.

DR. APOSTOLAKIS: Yeah, and then you have to be consistent with 1174.

MR. DINSMORE: So we could change, but I guess maybe another way to look at it is if we didn't -- we sat down and we tried to come up with groupings. We were directed by the Commission that we shouldn't look at just changes enabled by this new rule, which would have made it completely consistent with all of the other applications.

And so we tried to sit down, and we sat down with OGC, which makes it a little more difficult, and tried to come up with some way to group these things, and we couldn't, and if you don't group them, it's just --

MR. TSCHILTZ: Mike Tschiltz again.

The other issue here that we had come to the committee and talked to before is the issue of the parsing of the changes into changes that would meet the specific delta risk criteria so that, you know, you could make numerous changes of which if you considered each one individually, it would meet the criteria, but then if you were to combine them in a more logical way, then it would exceed the criteria.

So we were trying to determine a mechanism for preventing the misapplication, what we would consider to be the misapplication of the rule, and recognize, I think, as was pointed out just a couple of minutes ago that these changes, whereas before were under the guise of 1174, would always require prior staff approval. These changes aren't always in that situation now. They can be approved by licensees without prior staff approval.

So there is some concern there about, you know, where we should set the limits and the guidelines there as well. So those were some of the issues that we struggled with to come up with this accounting, and I recognize that there's a concern here.

I would offer there's another way to consider that we haven't pu much thought into, that you could limit the delta for changes that the licensee made without prior NRC approval, and then you know, default to the 1174 criteria for changes that came to the staff, but we really haven't thought much about that. That's not an issue that we're prepared to discuss.

But it kind of addresses the issue that you've raised, Dr. Apostolakis.

DR. APOSTOLAKIS: One of the ways of handling the total is to look at the goals, what is on the axis of these two diagrams in 1174, and maybe say the staff should consider the cumulative and put some words there to the effect that as you approach the goal, the approval will become more difficult or something like that.

In other words, you don't want to go to ten to the minus four because the way you interpret it now could require in your 1174 a statement to the effect that no matter what your CDF is now, it can never be increased more than ten to the minus five.

Well, that's a very strong statement. We never approved anything like that. That's what you're saying, and the LERF can never go higher than an increment of ten to the minus six, no matter what it is.

MR. TSCHILTZ: Just a perspective on that. I mean, if you look at the baseline CDS for the fleet of plants out there right now, we're talking that could typically result in a ten percent, 20 percent increase in their baseline CDF. I guess you have to be concerned of whether it's appropriate for a risk informed rule that's supposed to result in safety enhancements and improvements to allow increases in the baseline CDF that are a significant percentage of what exists right now, as opposed to incentivizing a system which you can offset risk increases with enhancements to the plant that decrease with risk as well to gain operational flexibility and reduced burden.

DR. APOSTOLAKIS: And I agree that you have a point. My objection is to the process because this issue should have been discussed or should be discussed in the revision to 1174 where perhaps other valid points will also be aired, but to do it in this rule and say we're consistent with 1174 when we are not, it seems to me not to be the proper way to proceed.

MR. DINSMORE: But then there was no other way to proceed rapidly with this rule. I mean --

DR. APOSTOLAKIS: Well, yes. Okay.

MR. DINSMORE: The alternatives --

DR. APOSTOLAKIS: There already has been a revision to 1174, and there can be a second one.

MR. DINSMORE: But I guess I'm unsure what you would suggest, that we would just say in this rule to use 1.174, which actually provides the opportunity as you said to walk up to ten to the minus four, and this is a rule, and it's going to require us to approve that.

DR. APOSTOLAKIS: The Commission issued the SRM to you or I don't know how they come in with the total, saying that you have to look at the total. Did you go back and inform them as to what that meant, that this means a significant departure from 1174?

Maybe they were not aware of it. I don't know.

MR. DINSMORE: There are certain restrictions about going back to the Commission. I don't know. I guess --

CHAIRMAN WALLIS: Does all of this detail have to be in the rule?

MR. DINSMORE: Well, the rule just says the overall CDF --

CHAIRMAN WALLIS: Can't you look at some other level?

MR. DINSMORE: -- the total increase in CDF and LERF is small.

CHAIRMAN WALLIS: Make it small and then work out some guidance to define better what it is.

MR. DINSMORE: If it didn't have total, total means -- the "total" word, if we just follow 1.174, the "total" word should not be there because --

DR. APOSTOLAKIS: That's right.

MR. DINSMORE: So it's there.

DR. APOSTOLAKIS: Or you can do what Dr. Wallis just said and take out the word "total," and in the regulatory guide, address the issue of what to do with the --

CHAIRMAN WALLIS: And maybe fix up 1174.

DR. APOSTOLAKIS: -- argue about the possible, you know, manipulation of the analytical results and then say this is what we mean, because if it turns out that what you mean is something that a lot of people find unreasonable and they give you valid arguments, it's easier to change a regulatory guide.

CHAIRMAN WALLIS: Absolutely.

DR. APOSTOLAKIS: So if you eliminate the word "total" here, then you have this flexibility.

MR. DINSMORE: Well, then you need a statement of considerations, and the statement of considerations is going to indicate that you could -- I mean there's --

DR. APOSTOLAKIS: I don't know. I mean, you have got to have a regulatory guide somewhere.

CHAIRMAN WALLIS: The rule should be at a higher level and may not need to get into such detail.

DR. APOSTOLAKIS: Yeah, which will pin you down.

MR. DINSMORE: I don't see how we could write a statement. The statement of considerations would pretty much say that they can raise the CDF at the plant to ten to the minus four under this rule.

DR. APOSTOLAKIS: No, no. I think even now you say that the regulatory guide will give the acceptance criteria for breaks above the TBS, right? I mean, what they need to do and all of that. And there will be a regulatory guide issued very soon.

DR. MAYNARD: Well, the rule gives requirements. The regulatory guide gives them essentially how they demonstrate that they meet those requirements.

DR. APOSTOLAKIS: Okay. So they can put it the way 1174 does and say the staff will consider and then explain in the regulatory guide what they mean.

MR. DINSMORE: I don't think the rule can say "consider." I think it gives you criteria, that you meet those criteria or you don't.

DR. APOSTOLAKIS: Okay. If you say the change should be small, where small will be determined in the regulatory guide, is that allowed? You say it's small now. You don't even --

CHAIRMAN WALLIS: Well, it's the same you do with hydraulics.

MR. DUDLEY: You'd have to give enough information in the statement of considerations that reasonable person can determine compliance with the rule or not, without having the reg guide because the reg guide is not before them, and that's the legal standard.

We don't have a lawyer here.

CHAIRMAN WALLIS: How can you do with the thermal hydraulics?

DR. APOSTOLAKIS: Right now you say the total increases in CDF and LERF are small, and the overall risk remains small. You don't say how small is small.

MR. DUDLEY: But in the Federal Register notice that we provided to you in the write-up, the statement of considerations, we have amplified that, and you have to have enough information between the rule and its implementing vehicle that a determination of compliance can be made without any external guidance.

CHAIRMAN WALLIS: Well, can I ask you then about the parallel with thermal hydraulics where it seems to be proposed to say you're going to have a coolable geometry without saying what it is?

DR. APOSTOLAKIS: Right.

CHAIRMAN WALLIS: I mean that's a similar thing. I'm just simply saying you'll have a coolable geometry, but we know that doesn't mean anything until you define what that is.

MR. DINSMORE: It also disrupts some of the other things. Dr. Shack, you were talking about how come they don't have to make submittals going down this other side. One of the reasons is they couldn't make ten to the minus five one after the other, because the total increase is ten to the minus five. So we'd have to go back and reevaluate a number of pieces of this rule because it was kind of fit together, and to just pull out that one piece, I don't think it's so simple.

CHAIRMAN WALLIS: The whole rule is full of all sorts of open ended things like this, like these alternative calculations that the licensee is allowed to make and keep in a drawer somewhere. That's an extra ordinary open ended thing, and we have to rely on the staff's wisdom in enforcing it properly.

It's the same thing here, the same thing with thermal hydraulics. There are a whole lot of open ended things in this rule that the staff is going to have to enforce somehow wisely.

MR. DINSMORE: This was also open ended, this little piece here, and we allowed it to be open ended because we had this backstop at ten to the minus five.

CHAIRMAN WALLIS: Why you have to have really wise guidance following up on this rule.

MR. DINSMORE: But the rule has --

DR. SHACK: No, the rule is the rule.

CHAIRMAN WALLIS: Well, I know, but it has to be interpreted somehow.

DR. SHACK: Well, I think we have sort of discussed this issue.

CHAIRMAN WALLIS: I think we have. I think we have.

DR. SHACK: We haven't come to a resolution. We'll have to reflect on what we want to say in our letter about this issue. Let's move on because we have other issues coming up.

MR. DINSMORE: That wasn't even the issue on this slide. Well, they'll be easier.

This is identification of changes that require prior staff review and approval. The proposed rule has said current regulatory requirements and any change that increases risk by more than a very small amount should be submitted. Comment from industry doesn't create current change processes, and so on.

And the new set-up that we've developed didn't include this. So the final rule just says you need to use your current processes.

Tracking risk increases. The proposed rule said the amount by which CDF and LERF increases over time must be estimated and tracked. The comment from the industry was it should be sufficient to estimate and track the overall CDF and LERF over time.

We didn't change the rule, and we didn't change it because a rule requires acceptance criteria to clarify for the staff, licensee, and the public what will be acceptable and what will not be acceptable, and the staff has no guidance on what is an acceptable overall CDF and LERF, but we do have guidance in 1174 in what is an acceptable risk increase and what is not an acceptable risk increase, and so we simply retain the requirement in the rule to estimate the parameters that we have criteria for.

And this one we already talked about. Do you want to just skip it or do you want to walk through it?

CHAIRMAN WALLIS: Whether you have to subtract or not, you mean?

DR. SHACK: No, the acceptance criteria.

CHAIRMAN WALLIS: Oh, the acceptance criteria. Okay.

DR. BANERJEE: Where's the acceptance?

CHAIRMAN WALLIS: It cites 1174.

It's Slide 13.

CHAIRMAN WALLIS: So we're skipping.

MR. DINSMORE: Skip or not skip?

CHAIRMAN WALLIS: Skip.

DR. APOSTOLAKIS: I have a comment on this one. I think the language of the rule should be changed somewhat. On page 7, you make a very clear statement. "The assessment must be based upon updated PRA and risk assessments." Okay? "The licensee shall" -- that's D(4) -- "the licensee shall periodically assess the cumulative effect of changes, and you make it very clear it will be updated based on an update PRA, right?

MR. DINSMORE: Right.

DR. APOSTOLAKIS: Then somewhere in there you say, well, there may be other changes, but I need a qualitative evaluation, which is fine.

But then on page 10, two, requirements for risk assessment, which is also what you have here, you list six requirements, but you start out by saying, "To the extent that the PRA is used in the risk informed evaluation." I mean that gives me at least the wrong impression that I have a choice of using a PRA or something else.

I would say when the PRA is used --

MR. DINSMORE: Okay.

DR. APOSTOLAKIS: -- in the previous three pages survey, you say that you have to use a PRA. Because you are imposing all of these requirements on the PRA. So I may choose not to use a PRA then, and I get three --

MR. DINSMORE: Well, there is a requirement for when you use a PRA, and that's actually probably --

DR. APOSTOLAKIS: That was before, on page 7.

MR. DINSMORE: No, if you look at 2(i).

DR. APOSTOLAKIS: Where?

MR. DINSMORE: Two, little I. Actually it's says, "To the extent that a PRA is used in the risk informed evaluation, the PRA must address initiating events."

DR. APOSTOLAKIS: I know. I know that.

MR. DINSMORE: That tells you when you have to use it.

DR. APOSTOLAKIS: No. You start off by saying, "To the extent that the PRA is used." In other words, I may choose not to use it. If I use it, I have these six requirements.

MR. DINSMORE: Well, the intention was you have to use it.

DR. APOSTOLAKIS: Exactly. What I'm saying: can you change those words "to the extent" and --

MR. DINSMORE: We can change it.

DR. APOSTOLAKIS: -- say when a PRA is used? Because you have already said that it has to be used.

MR. DINSMORE: We can change it to clarify. We got a public comment along that. We didn't really change anything, but I suppose --

DR. APOSTOLAKIS: Now you're getting an ACRS, a member's comment.

MR. DINSMORE: We'll talk to OGC and make sure that the intent --

DR. APOSTOLAKIS: Do you understand my concern?

MR. DINSMORE: Yes, yes.

DR. APOSTOLAKIS: It gives the impression that, oh, okay, I can use PRA or something else or maybe a little bit of PRA, and to the extent I use it, I make sure it's okay.

So if I don't use it, these six requirements go out of the window. But earlier though you are very explicit. You are saying the assessment must be based upon an updated PRA, which is, I think, what you mean.

MR. DINSMORE: Yeah. Here we --

DR. APOSTOLAKIS: You can even say here to the extent that the PRA is used as stated in D(4), to make it clear that it must be used.

MR. DINSMORE: Well, it only must be used if the -- well, to the extent that it addressed all sources of internal --

DR. APOSTOLAKIS: That's also true, but I think what you mean in the rule is that if you can quantify the CDF, you must use PRA. Only cases where you --

MR. DINSMORE: No.

DR. APOSTOLAKIS: -- can't. Oh, then we have a big problem.

MR. DINSMORE: The rule is supposed to say if you have to quantify CDF and LERF you have to.

DR. APOSTOLAKIS: And that's what I just said.

MR. DINSMORE: Okay.

DR. APOSTOLAKIS: And when do you have to? When you can?

MR. DINSMORE: No, when it would effect the regulatory decision in a substantial manner.

DR. APOSTOLAKIS: Right, right, right. I

grant you this qualitative part when it is extremely small and you gave us examples yesterday what is it, the parking lot, was it that we said?

MR. DINSMORE: The curbs in the parking lot.

DR. APOSTOLAKIS: Yeah, the curb in the parking lot. Yeah, I have no problem with that, but if you are effecting SSEs that are part of the accident sequences, then we all know that delta CDF can be calculated because there is a lot in the PRA. And then you demand the PRA it seems to me. Right, and that PRA has to meet all these requirements.

MR. DINSMORE: If it effects the decision in a substantial manner I guess --

DR. APOSTOLAKIS: No, I wouldn't agree with that because you don't know in advance whether it effects it in a substantial manner. I mean, in a trivial case --

MR. DINSMORE: Well, you would. Some places -- okay, in many cases you might not, in which case you'd have to do the PRA to show that you didn't need it. That's -- I agree with that.

DR. APOSTOLAKIS: Then you're saying I will make a qualitative judgment in advance that this thing, even though it can be quantified, it will not effect the PRA so I don't need to quantify it. I mean, come on, we can't run a business that way. Do it. I mean, if you can quantify it, quantify it.

MR. DINSMORE: I didn't think --

CHAIRMAN WALLACE: Even bounded quantitatively, even bounded quantitatively, that's okay.

DR. APOSTOLAKIS: Sure. I don't care but it would be quantitative. Anyway that words bother me to the extent that the PRA is used.

MR. DINSMORE: I'm making a note on that. Actually, this is another one which we would have difficulty if we were to try to take the word "total" out because this is about the reporting requirements. The proposal rule said you needed a PRA update every two refueling outages and reporting of change as a result in a significant reduction in the capability to meet the acceptance criteria and a short description of all changes involving minimal increases in risk. The industry comment was they proposed a PRA update every two refueling outages to assess the cumulative effect of changes in reporting of the results, either the CDF and risk assessment to the NRC.

So we went back a little and we tried to figure out what exactly would we need to be reported and we didn't like the significant reduction capability. It doesn't -- it wasn't enough of a criteria, so that people would know what they should report and what they shouldn't report and so we took that out and we eventually replaced it with, well, if we have a criteria, and we were looking at the ECCS rule which says if you find errors and you exceed your temperature calculations or your temperature limit, you have to report that you've exceeded the limit and here's what you're going to do to fix it. And so we simply paralleled that and said, well, if we have an acceptance criteria here for increases in LERF, if you do your update and you find out that you've exceeded it, you need to -- what we really need is the steps in the schedule to bring the facility back into compliance with the acceptance criteria.

And then that last one is the potentially risk significant changes implemented without NRC review that increased risk greater very small which is the changes that you were pointing out that they could do without reporting and this would be that long-term monitoring just to make sure that we understand what's going on and what they're doing on their own.

We come to this one. Operating restrictions when in a configuration not demonstrated to meet the ECCS acceptance criteria for breaks greater than TBS. I'm going to give you a quick description again of what that means. PI's will most likely be permitted to raise power because of the smaller design basis LOCA because single failure criteria and the simultaneous loss of offsite power are not required for breaks greater than TBS, it is likely that some facilities may credit both LPSI trains to demonstrate mitigation of the largest break.

The question arises is what do we do about operating when for example, one of the LPSI trains is out for maintenance? Assuming that no other non-safety related equipment can be used as a LPSI or to replace the LPSI when one train is out, the facility would be operating in the configuration not demonstrated to meet the ECCS criteria. Does that explain it well enough?

DR. APOSTOLAKIS: If one train is out, the other still can provide sufficient cooling, no?

MR. DINSMORE: No, it would be --

PARTICIPANT: It's not proven.

MR. DUDLEY: After a power-up --

DR. APOSTOLAKIS: Oh, after the power operates, I see, because right now it can't.

MR. DINSMORE: Right now it can't, right.

SB: Are you going to discuss the acceptance criteria over at TBS because I think the full committee should hear this.

MR. DINSMORE: The thermal hydraulics acceptance criteria?

SB: Yeah, I think this would be of interest to everybody.

CHAIRMAN WALLACE: I don't think we know what they are.

SB: Well, that's part of it, right?

DR. APOSTOLAKIS: What are you proposing?

MR. DINSMORE: The rule says coolable geometry.

CHAIRMAN WALLACE: That doesn't mean anything.

MR. TSCHILTZ: I can clarify that. For all practical purposes, the criteria for coolable geometry is what exists right now, the 2200 and 17 percent. That doesn't change. The rule facilitates if licensees or the industry would choose to do research that would justify or could justify something other than those limits and that the staff would review and find acceptable, it would allow them to use those in lieu of the existing limits but right now all the rule does is allows that option but for practical purposes the limits remain the same.

MR. RUBEN: If I could add, there's also differences in the analysis methods and assumptions that are very significant. You don't have to assume single failure. You don't have to assume loss of offsite power which gives them a lot more flexibility in the analysis, plus the analysis method itself used to demonstrate compliance with the initial criteria on peak clad temperature and oxidation can be a more best estimate model.

CHAIRMAN WALLACE: I've been looking for that. I can find the business of the single failure taking out that and taking out the offsite power, but where are these other concessions in the rule? I can't find them. They seem to be concessions about some other mysterious calculation unreviewed by the staff being allowed. Does that appear in the rules or is that in the guidance? In the rule somewhere, it's actually in the rule itself?

DR. BONACA: Yeah, I would like to finish my -- I need to have an additional answer to my question.

DR. APOSTOLAKIS: Can we go back to your question and remind us of it? What was your question?

DR. BONACA: My question is operating in a configuration not demonstrated to meet. Okay, now is that --

DR. APOSTOLAKIS: Where are you reading? Here this?

DR. BONACA: Number 1. Now, I could read that as saying not demonstrated but still believed to provide sufficient or adequate cooling. Or I could read it simply that it's for 14 days I don't have to prove anything. You can take everything out of service and that's okay, and, you know, I don't buy that.

MR. TSCHILTZ: I could clarify that.

DR. APOSTOLAKIS: It's taken just to the extreme.

DR. BONACA: Yeah.

DR. APOSTOLAKIS: You say I have no cooling capability at all.

DR. BONACA: Well, I don't know what it

means. I'm asking what that means. Does it mean that it's not the most preferred but there is a belief that it will work? No, it means, you have no burden of proof.

PARTICIPANT: Not demonstrated.

DR. BONACA: -- if you just check it out for two weeks. How should I feel sorry about the fact that the plant wasn't designed for that maintenance on line that way and now I have to make this concession without understanding what it means.

MR. TSCHILTZ: Can I clarify on that point? I think the existing tech specs are going to limit the time that a single LPSI pump can be out of service. So in many instances, in fact, most instances, the tech specs will be limiting and for equipment not covered in tech specs, it may be at some point credited for mitigating the greater than PBS break, this would come into play.

As far as not having an analysis for those situations where you could have a break greater than PBS and not be able to mitigate, the rule right now doesn't require that but that Commission basically told the staff to maintain the capability to mitigate a double-ended guillotine break commensurate with the its risk significance. So the staff went through the exercise of trying to go through some evaluation of the risks posed by this fairly rare event that would be created by allowing short periods of time with the inability to mitigate a double-ended guillotine break.

DR. BONACA: And this is pervasive until they change the rule, I agree with that. We have risk considerations. But essentially, you're also making a commitment to defense in depth. And here you're leaving a window. Well, I got to understand what the means, because it says you're still making such a judgment based on a risk basis that you're not providing for any protection for 10 days. Now, I can calculate everything I can but simply what it says to me is that for those 14 days, there is no mitigation.

MR. TSCHILTZ: That's correct. The rule would not require mitigation for a cumulative period of up to 14 days.

DR. BONACA: Yeah, I understand the rule is written this way, but I don't have to like it.

MR. TSCHILTZ: I think you understand what we've written.

DR. SHACK: Let me ask a related question. Other equipment that's now governed by tech specs but because the large break LOCA above the TBS is no longer going to be a design basis accident, will they be able to come in and the -- if that equipment is only needed to mitigate the breaks above the TBS, will essentially all requirements on that default back to this 14-day requirement?

MR. DINSMORE: You mean it would only need to be operable for 14 --

DR. SHACK: Right, the tech specs not have other limits on its operability and availability. If it was no longer part of the design basis, would it then default back to this 14 days?

MR. DINSMORE: We're aware that for the LPSIs for example, they're going to have to keep their current tech specs because everything has to be there for the below TBS.

DR. SHACK: For the lowest TBS.

MR. DINSMORE: You're talking about some equipment that is --

DR. SHACK: Yeah, it's just --

MR. DINSMORE: -- not required for below TBS? If it's not required for below TBS, I guess I'm confused. I'm sorry.

DR. APOSTOLAKIS: Let me understand the question.

PARTICIPANT: I believe they'd be allowed to --

DR. SHACK: If there was some equipment, you really didn't need it to mitigate breaks below the TBS, it was --

DR. APOSTOLAKIS: It would not be under the tech specs?

DR. SHACK: It would not be under the tech specs, that's --

DR. APOSTOLAKIS: And then you would have the problem that Mario --

DR. SHACK: Well, it would be under these 14 days. It would escape the tech specs and be captured in the 14 days.

MR. DUDLEY: Yes, Dr. Shack, that's our understanding.

DR. SHACK: That's your understanding.

MR. DUDLEY: Yes.

SB: So if you, let's say had a bar operate and to cool the core you would need two LPSIs and below the TBS you'd only need one because you could knock out one with the single failure criteria. So you'd be allowed to now operate for 14 days, just -- no, you'd have to have one.

MR. DINSMORE: With one, yes.

SB: With one.

MR. DUDLEY: One because you'd need it for your TBS design --

MR. TSCHILTZ: No, the existing tech specs would rule which the existing tech specs for most plants are 72 hours in that condition with one -- for a PWR low-pressure injection. So those would continue to control and be limiting.

DR. MAYNARD: First of all, these things do not automatically come out of the tech specs if it's no longer required. There would have to be a license amendment submitted and reviewed by the staff and you also have the criteria of you know, there's only so much of a reduction in your overall PRA that you can accept your CDF or your LERC. So things aren't going to happen beyond the staff's ability to review and have control of, too.

MR. RUBEN: Let me add an additional perspective as well. This is Mark Ruben again. The defined condition of the plant in the rule is an unanalyzed condition, meaning that the success criteria has now changed for the success for a double-ended guillotine break. That doesn't mean that you have no potential mitigation capability.

It doesn't mean that if you have a break one inch greater than the TBS size you have core melt and vessel failure. And it doesn't necessarily mean that if you have the double guillotine break, you'll have such significant core damage that you're guaranteed a vessel failure and a potential containment failure after that. It's just that we don't know.

The analysis methods are not fully developed for, you know, in vessel progression and high likelihood you know, to calculate those things and as Mr. Tschiltz said, we're open to the industry if they could come out with sort of an interim criteria that would allow perhaps a little more fuel damage but still demonstrate coolable geometry. And the fact that you may, indeed survive a double ended guillotine break with a single LPSI even given you may have some fuel failure, is a credible potential outcome. We just don't know. We haven't calculated it, analyzed it to a limit that we know would give you high assurance of meeting that.

DR. BONACA: Oh, I understand, but again, going to the comment of every amendment is going to be reviewed, it interprets, and we discussed this already before, Reg I 1.174 is a license to evaluate increments and to march on increasing continuously by some small amount core damage frequency and fuel limit, and it makes a parallel between the typical design basis in the termalistics (phonetic) place where you put a limit to your peak pressure in the vessel of 2750 psi but the limit has a different kind of connotation. It's a very high limit with a huge amount of margin to it to account for uncertainties.

Here, we are marching on to some criteria maybe 10^4 and there is significant uncertainty about that value. And the question I'm questioning this process of incremental, you know, and which is nebulous part. We are approving a rule here that would allow for a lot of amendments to come in to get margin and it will be always in the continuous direction of reducing or increasing risk by some small amount supposedly but --

DR. SHACK: But I mean, they have a total cap of 10^5 increase.

MR. DINSMORE: The rule as written does not give you a nebulous --

DR. APOSTOLAKIS: But there is -- Bill, you said that for the equipment that will not be needed for under PBS, those are outside the tech specs but Otto said that, no, in order to take out, you will have to do a risk evaluation; is that correct?

DR. SHACK: Yes, but again, if you come into this thing and look at the risk evaluation above the TBS, for breaks with, you know, simultaneous LOOP, you're going to get very small Delta CDFs. I mean, that's how we pick the TBS.

DR. APOSTOLAKIS: No, but you will have to request the --

DR. SHACK: You'll have to request -- I'm not even sure you'll have to request it because I can make a change of that magnitude without a request, I could even do it.

MR. DINSMORE: If it's a tech spec item, it requires --

DR. SHACK: Okay, but again, it will certainly meet the 1174 requirements.

MR. DINSMORE: If it's a tech spec you'd have to come in with a submittal. If it's not a tech spec, we actually have been discussing you could make an administrative change to your FSAR which would put it in that left-hand column so that they'd have to do the risk analysis but they wouldn't have to submit it and --

DR. MAYNARD: If it's not in the tech specs, it's probably not something that you're really relying on, so there's not too many things outside of the tech specs that --

MR. RUBEN: Let me point out also, Mark Ruben again, that the current provisions in 174, but it's a reg guide, of course, not a rule, theoretically allows this march up to 8^{-4} and in fact, that was a major topic of discussion between the committee and the staff. And what we pointed out was that yeah, theoretically it could permit that but it was not the intent of the staff nor in fact, the intent of the industry to allow that to happen and we watched the progressive risk informed changes allowed under 174 and the association application specific guides and if was saw a trend of a plant with low risk marching boldly up there, we would not -- we would stop it. We would not approve it because it would not be the spirit of the concept of risk informed regulation.

Now, we're dealing with a rule that has to be very explicit. And so there has to be a little more definitive criteria, ie, small or very small that we defined in the reg guide but in any event, we're dedicated to prohibiting the eventuality you're talking about.

DR. APOSTOLAKIS: But then, Mark, why don't you take what you just said and find the appropriate language to put it in the rule rather than changing the fundamental premise that the Delta CDF of 10^{-5} now refers to cumulative? That's a pretty significant change. I mean, I agree with what you just said and the understanding was always that that would be the case. Can we find an appropriate language to put it in the rule to reflect that?

MR. RUBEN: The current rule would actually prohibit that from happening and so it would, it would. So --

DR. APOSTOLAKIS: But it would go way, though, to the other side.

MR. RUBEN: That's our proposal based on the guidance we've gotten from the Commission. It's certainly a good point. When the expanded the evaluation scope from just 5046 related changes to all changes made that they should be evaluated risk informed, that was in response to a draft rule in a SECY paper that included the present criteria for change. So we were directed to expand the scope. We were not directed to change the criteria or even ask to assess the criteria further.

We thought it was workable and was certainly in response to the SRM guidance, so that's why we stayed with it.

CHAIRMAN WALLACE: Mark, I have a serious question for you. You seem to be assuming that risk is going to somehow catch things which are allowed under this rule which might lead to significant core damage with say a large break. Now, what goes into this risk analysis? You've got to put in the initiating frequencies. Are you going to put in initiating frequency for a large break according to this NUREG 1829 which says it's 10^{-8} or something? In that case, it will never appear in the CDF anyway. So the CDF doesn't provide any assurance that the large break is suitably handled.

MR. RUBEN: Well, Dr. Wallace, that's a truly outstanding question because it's been one that we've been fretting, puzzling over from the very beginning. With the incentive to use the best information possible in PRA updates, it would clearly suggest that the best available information is that from the elicitation.

CHAIRMAN WALLACE: The TBS was unnecessary because all those breaks will disappear from the PRA anyway.

MR. RUBEN: Well, remember, we would probably be using the mean values not an upper confidence bound limit in the nominal calculation or we'd reflect the full uncertainty distribution. Plus the fact that the current numbers that are generally accepted without a lot of argument are the ones in 5750 and if you look at the mean value curves, the estimates are -- from the elicitation process are not wildly different in most cases. The middle -- mid-sized break goes up a little bit. The larger breaks go down somewhat and if you get to a full double-ended guillotine break, yes, it goes down quite a bit.

CHAIRMAN WALLACE: Fierce isn't it?

MR. DINSMORE: Yeah, but the numbers, the breaks in the PRAs are smaller breaks. The biggest break in the PRA is probably five or six inches.

CHAIRMAN WALLACE: The PRA doesn't consider the large break?

MR. RUBEN: That's one of the challenge is the --

CHAIRMAN WALLACE: So how can it possibly be an insurance policy about over-estimating the risk, under-estimating the risk of a larger break?

It can't.

DR. APOSTOLAKIS: It seems to me that really what we're saying here is that all the requirements we're imposing for breaks greater than the TBS are really defense in depth requirements and it's consistent with what you just --

CHAIRMAN WALLACE: But then the argument we have with Corradini was that if you somehow -- the thermal hydraulics is not really doing a very good job and the temperature goes up to 2700, that will be caught somehow by the risk analysis but apparently it isn't.

DR. APOSTOLAKIS: Not the risk, not the risk.

CHAIRMAN WALLACE: Well, what catches it? I mean, what really made me sit up is when you were saying we don't know, you know, what will be the consequences of the large break.

SB: How does defense in depth work here? You're entering unknown territory, right? I mean, imagine there's significant core damage. There's oxidation, hydrogen, I mean, God knows what's going on.

DR. SHACK: No, they're restricted to essentially, as he said, the current acceptance criteria.

SB: But they are not, they are not. It's not stated specifically.

DR. SHACK: Well, you have to demonstrate that you have something roughly equivalent.

DR. ARMIJO: Well, why don't they just state there what they want and then --

DR. SHACK: Well, that's a different question.

DR. ARMIJO: And then let somebody propose an alternative if they can't meet it?

DR. SHACK: That's what the reg guide does.

DR. ARMIJO: I'd feel better about this thing.

SB: Plus, you can use best estimate probably. I mean, you don't know what you're getting into right here. It's a mess.

DR. APOSTOLAKIS: No, it will be again -- I mean, defense in depth in the traditional sense has always been a matter of judgment, it seems to me. And from that point of view, it doesn't change here either.

SB: Well, if they said you have to do everything the same but you don't have to have single failures or LOOP, then perhaps one can think about it, exactly the same rules except those two. But otherwise you're just opening up, I mean, I could find a way to do this and probably use some best estimate and get away and yeah, sharpen my pencil and happily work --

DR. APOSTOLAKIS: Well, that's what the staff said, that the core level geometry essentially means these requirements, these acceptable requirements.

CHAIRMAN WALLACE: They haven't said it in writing.

DR. SHACK: Well, again, we can rewrite the rule later. Let's just continue our presentation. I'd like to finish here so the BWR people have a chance to say something.

DR. POWERS: Before we move farther along, have you looked to see how the seismic risk would change if you made these changes to the rule. And the motivation for asking this is I get a strong impression from what I read that LOOP and break are viewed as independent events and with the seismic they're not.

MR. RUBEN: One small comment and then Mr. Dinsmore can give a complete answer. In the work we're doing on the LOCA LOOP BWR topical and associated technical resolution of the issues, LOCA and LOOP are not truly fully independent. There is some data that the Office of Research has evaluated in great detail that shows some correlation due to the possibility of great instability following the trip of a plant and the high loads from all the emergency systems coming on line, but it certainly is much less correlated than seismic. Steve, go ahead.

MR. DINSMORE: I'm trying desperately to remember all the conversations we had about seismic. Essentially we were talking about if you have a big seismic event and you don't have a crack but the problem with seismic and TBS was if you had a big crack or not. If you don't have a big crack, by the time you get to a seismic event that's ripping pipes apart, you're probably failing both trains that you had anyway. So at those big seismic events, we didn't think it was going to make much difference on the risk. If you've got a big enough seismic event, it would fail enough piping and enough systems that you'd -- it doesn't matter if you needed one LPSI pumps or two, you wouldn't have enough.

I believe that was the -- those were

without cracks in the pipes. Having cracks in the such that you could get big pipe ruptures with smaller seismic events which would cause this problem to come up, I'd like to throw it over there to Tim, it's -- the staff moved ahead by concluding that it was unlikely that there was going to be cracks big enough such that a 10^{-5} earthquake would cause a rupture and that's one of the reasons why we're re-evaluating the Wolf Creek cracks.

CHAIRMAN WALLACE: How effective is the earthquake on the switch yard and the grid?

MR. DINSMORE: The switch yard and the grid are gone pretty quickly.

CHAIRMAN WALLACE: So you've got your LOOP and now your question only is do you also have a LOCA.

MR. DINSMORE: Right, and the LOCA is the one if there's no cracks we doubt that you're going to get the LOCA.

CHAIRMAN WALLACE: But you've certainly had the LOOP.

MR. DINSMORE: Yes.

DR. BONACA: When you talk about seismic a large or a small, could you please make a reference to the design ground acceleration of the plant? I mean, is it the demarcation point in your judgment or is it the frequency?

MR. DINSMORE: It's a frequency. 10^{-5} is the -- we were looking at 10^{-5} because it's the same frequency as these pipe breaks. That's the kind of -- so large would be --

DR. BONACA: I just -- I cannot correlate that with the design basis.

MR. RUBEN: Let me -- I could provide a little bit of supplementation but please be gentle with me, this is not my area. I'm not a structural seismic analyst. The plants are designed to at SSE, Safe Shutdown Earthquake, G loading and you know, it's promulgated by the ground structure and the vertical structure that goes through the plant to the particular components. Typically, that can be .15 G, .2, but and this is the important but, the plant usually has seismic capability well beyond that because of the margins in the fragilities of the actual components.

You lose offsite power at about .1 g. That's below the safe shutdown earthquake. That's why we have diesel generators. The seismic capability, I you look at a fragility analysis, of some of the major components and support structures, pipes, I think I've heard as high as 2 g before you'd exceed all that margin they have with the seismic supports and the piping inherent strength, but again that's assuming that --

DR. POWERS: But your questioning me to death. You're just speculating here and the question is, how does the risk change if you make these changes to the plant design criteria and the success criteria. And yeah, I can find you places in the plant that will survive 10 gs. I can find you places in the plant that won't survive .2. That doesn't answer the question, how does risk -- fundamentally the problem is that every time we come around and talk about 1.174 or any kind of risk, all we talk about is operational events.

We're getting plants now, the new plants are coming in where their operational CDFs are something like 10^{-8} and they will be totally dominated by seismic considerations and that's not coming in to the discussion here and this been predicated -- I don't know how many times I've seen this, "Oh, well, LOOP, we don't need to consider that because it's independent of the break". Well, it's not under a seismic event and that doesn't seem to have effected this discussion at all.

MR. DINSMORE: Well, there's a NUREG out and maybe -- we did an analysis which I gave you a very bad overview, I guess. Tim.

MR. COLLINS: This is Tim Collins from the staff. With regard to seismic, let me just go back a little bit. When the TBS was first developed there was kind of an assumption that seismic contribution was not going to be important. Okay, and so the -- we came up with our original number for TBS. And then the Office of Research went and undertook a study to see, well, maybe we ought to look a little closer at that and see if seismic is important, okay.

And in December, we put up on the website the results of a study that the Office of Research performed. And basically, they concluded that for earthquakes of a frequency on the order of 10^{-5} or 10^{-6} on flood pipes wouldn't fail in the loadings of the earthquake. And then they went about to try to calculate how big of a flaw you would have to have in a pipe for the pipe to fail under that same earthquake. And they concluded that if you had a crack on the order of 40 percent through the wall, 180 degrees around, it's going to break under those earthquake loads.

So the question became how likely is it that we have cracks this big in pipes that are bigger than the TBS, basically the main coolant pipes, okay. And so we went back and we looked at experience in cracks and both fabrication flaws and service induced flaws. And experience said from fabrication flaws nothing was ever found that came any place near the size of a crack that would cause this problem. Then we considered, well, maybe we didn't find it when we looked at it and it missed inspections, right.

Well, we thought 20 years of operation, more than 20 years in almost all these plants, we've never seen a leak which we would attribute to a fabrication flaw that is threatening, okay. Then we looked at service induced flaws and we said for boilers we figured that IGSCC was really the only service induced mechanism that was a threat to give cracks this big and we believe that that's being well enough managed. Okay, then we looked at PWRs and said PWSCC is the mechanism that could cause a service induced flaw.

And the experience with that was that the flaws we've seen are relatively small and even though the programs for managing it we don't think are fully developed, they're in place and they're being further developed. So we thought that between the experience we've had with flaws and the fact that we've got a deliberate program to manage them, the likelihood of very large cracks being present were small.

And so based on that, we thought that the seismic risk contribution would be small.

DR. POWERS: You've just convinced me I never need to take a break ever.

DR. SHACK: Pardon me?

DR. POWERS: You're just convinced me there's no possibility of ever having a pipe break.

DR. SHACK: Well, we think it's just small enough that it's not going to happen. I mean, that's what we're saying.

MR. COLLINS: Essentially you have said, "Don't worry about pipe breaks at all, ever. They're not going to be caused by seismic which is the only stress that ever comes onto them and clearly operation doesn't put any kind of stress like that on them.

DR. SHACK: If we thought they were never going to happen, then we wouldn't have the defense in depth requirement that you'd still be able to mitigate the full double-ended break, if we were absolutely convinced.

DR. BONACA: We never thought that Davis Bessie could happen.

DR. ARMIJO: Did you consider the smaller pipes, what kind of a flaw depth and circumferential damage would cause them to break in that same earthquake? Is it 40 percent through wall or --

MR. COLLINS: We were only considering the largest pipes, that's all we were looking at.

DR. ARMIJO: But couldn't you have multiple failures of smaller pipes which would create the effect of a large break LOCA? Did you address that?

MR. COLLINS: No, we did not. We did not.

DR. APOSTOLAKIS: So the position of the staff is that the seismic risk is negligible.

DR. POWERS: Yes. It wouldn't change what we have in the rule today.

MR. COLLINS: For a TBS of these sizes.

DR. POWERS: Right, for a TBS of this size, we concluded that we would not change the rule based on seismic considerations and that was --

CHAIRMAN WALLACE: So apparently the multiple breaks was not part of your consideration.

DR. POWERS: That's correct. Yeah, that's correct.

SB: What is the potential for multiple breaks?

CHAIRMAN WALLACE: Well, if it's a big enough earthquake it's --

DR. ARMIJO: Yeah, and if you've got flawed pipes, obviously you don't want to -- if you don't have flawed pipes, you're going to be --

PARTICIPANT: Well, you don't really know if you have flawed pipes.

DR. MAYNARD: If you're above your design basis earthquake, if you're above the SSE then you are basically in some unanalyzed situation and you've got to deal with that. Below the SSE you're designed to take that.

CHAIRMAN WALLACE: The earthquake could shake your accumulators and break them off, too. I mean, there's lots of things you can hypothesize in an earthquake.

DR. ARMIJO: We were talking about something with a precrack due to materials degradation.

CHAIRMAN WALLACE: Right.

DR. ARMIJO: And the seismic event being

the initiator and the big pipes apparently are really low risk but the question is, can you get the same square foot break with more than one pipe breaking if there are flaws.

DR. MAYNARD: I think my answer to Dana's question would be that the risk increases, I mean, for what you're doing. If you start taking anything out of service, you have an SSE with loss of offsite power that you are going to have an increase in risk. It's not necessarily a big or an unacceptable increase in risk because you still have the equipment to mitigate it. Diesel generators, you're still going to have power. They may -- you may have gone and justified longer start times or whatever, but you're still going to have electric power, but I think bottom line, the risk increases. Quantity, I'm not sure, it would have to be evaluated for each plant.

DR. POWERS: And my frustration, Otto, is that it never gets evaluated. Nobody ever actually goes and looks at these things and they apply 1.174 and things like that without ever looking at this and here, it just strikes me you just cannot go blissfully along and not look at it. Mr. Collins has convinced me that we don't have to ever worry about breaks period.

DR. APOSTOLAKIS: But I think he's referring to a single pipe failing and I'm trying to understand the --

DR. POWERS: Yeah, I understand Sam's argument as well and it's a good one.

DR. APOSTOLAKIS: Yeah, has anybody ever in seismic risks assessment, I don't remember myself, considered multiple smaller breaks and how the plant would respond?

MR. COLLINS: I don't know. I'm not the seismic guy. I'm just carrying the message for him. The seismic guy is not here today.

DR. APOSTOLAKIS: Well, that would be an interesting thing to consider, right? I have never seen them.

DR. BONACA: I never seen those multiple breaks.

DR. POWERS: Well, I think you've asked this question once before, George, and the answer was, no, that they did not and it's particularly troublesome because what got us in trouble with Chernobyl was breaking multiple pipes, not just breaking one.

DR. APOSTOLAKIS: Yeah. When was the last time we had a presentation from the cognizant group here at the agency on seismic risk? I don't recall.

DR. POWERS: Some time back.

DR. APOSTOLAKIS: Maybe we should have another one. They have a big meeting organized by the OECD and --

CHAIRMAN WALLACE: George, do you need this before you decide on this rule?

DR. APOSTOLAKIS: Well, that's an additional element. No, no, but I mean, since we are talking --

CHAIRMAN WALLACE: No, you don't need it, you don't need it.

DR. APOSTOLAKIS: Well --

CHAIRMAN WALLACE: Is it a condition or is it something --

DR. APOSTOLAKIS: No, it's not a condition, but I think we should have a session with the appropriate group to air these questions and ask them why the --

CHAIRMAN WALLACE: And then we can retroactively see what effect it might have on this rule.

DR. APOSTOLAKIS: I'm saying that there is a major international meeting this next week in

Korea where the big names will get together.

CHAIRMAN WALLACE: Well, we've raised another issue. Should we move on?

DR. SHACK: We're going to bring the BWR people up at this point.

DR. APOSTOLAKIS: Are you done?

CHAIRMAN WALLACE: Are you finished?

MR. DINSMORE: We are --

(All talking at once)

DR. APOSTOLAKIS: Well, is there anything else in your slides?

MR. DINSMORE: It's the justification for 14 days based on risk.

DR. APOSTOLAKIS: Which is not in the draft rule we have. It's seven days there, right?

MR. DINSMORE: Right, yes.

DR. BONACA: And if I remember, you can bundle together changes, right?

DR. APOSTOLAKIS: Yes.

MR. DINSMORE: Yes, the rule actually requires you to bundle all changes together.

DR. BONACA: But also resulting from known LOCA related.

MR. DINSMORE: Yes.

DR. BONACA: You can bundle them all

together.

DR. APOSTOLAKIS: But it is, I mean, coming -- a counter-argument to splitting the Delta CDF into smaller Delta CDFs, you may find yourself in a situation where you have an increase in one sequence and decrease in other sequences, so that average is okay, but you really are not prepared to live with such an increase on that particular sequence. I mean, that's conceivable to me.

MR. DINSMORE: Well, there are the guidelines in 174 that says you can't -- when you bundle, you can't take non-significant sequences and make them significant and so we were going to carry those over if we get that far.

MR. RUBEN: Plus there a criteria not --

DR. APOSTOLAKIS: From 1.174, you take what you like and you don't -- don't take what you don't like.

MR. DINSMORE: We had lots of input and we were trying to live within the input.

DR. SHACK: Can we move on, George?

DR. APOSTOLAKIS: Yes, I never stop you from moving on.

DR. SHACK: Well, you guys are coming up.

DR. APOSTOLAKIS: So now we have NEI, oh, BWR.

(Off the record comments)

MR. BROWNING: Unless you're real good at this I'll give you a hand.

DR. APOSTOLAKIS: You find it, you open it.

(Off the record comments)

MR. BROWNING: Good afternoon. I'm Tony Browning. I'm the Chairman of the BWR Owners Group, Option 3 Committee. As you may be aware, we are the actual group that did the topical report of separating the loss of offsite power from the large break LOCA that currently the staff is reviewing. And a lot of what's in the topical is germane to this rulemaking as well, and that's one of the reasons why I'm here talking about it, because of our experience with that effort and how it could be useful in forming a positive rule for the BWR community and that's one of the reasons why we came to talk.

Again, we're pleased that the initiative has made it this far. I mean, this has been an arduous path for all of us and we recognize that. There are a lot of issues that still need to be, you know, put to bed and one of the things that we wanted to come and talk about specifically was the transition break size and our concern here is, while we've made a significant amount of progress to date with this rule, it's unlikely as it's currently configured and written that any BWR would implement this current rule because of the lack of cost benefit to us with a transition break size this high.

And that was of concern to us. We've made comment on it on the draft rule and on the elicitation and we wanted to come and present some new information that we hope that the staff and the ACRS can use to understand our position here and to help us move forward in crafting a rule that we can all use.

While we don't take specific criticism of the elicitation process itself and we don't believe that it is inherently overly conservative, the problem that we had with it was that the way the staff utilized it later, and basically padded the results that we thought were already conservative in the elicitation to arrive at a TBS that was too large. And when you consider proper credit for the failure mechanisms that were discussed in the elicitation such as IGSEC, FAC and thermal fatigue, if you take credit for the conservatism that was built into the elicitation, we don't believe that the extra conservatism that the staff put on for these unknown mechanisms and for these other failure modes is necessary, that the original elicitation was conservative enough for a risk-informed rule of this nature.

And we would be happy to come back at some future time and bring materials people and explore that in more depth in another forum.

CHAIRMAN WALLACE: Are you saying then in the second bullet that it makes no sense to have this rule at all unless it is changed?

MR. BROWNING: We're saying that we can't speak for every BWR but it's highly unlikely based on our work to date that with a transition break size this large of 24 inches, that any -- BWR would derive enough benefit to outweigh the cost of implementation. And because it's a voluntary rule, we don't see people queuing up to come and adopt it.

DR. APOSTOLAKIS: This is a motivation for you to come before us. This cannot be an argument for us to change the rule.

MR. BROWNING: That is correct.

DR. APOSTOLAKIS: Okay.

DR. POWERS: Yes, but his argument on the conservatisms and compounding conservatisms from the elicitation to the rule is very germane here.

MR. BROWNING: Yeah.

DR. APOSTOLAKIS: Yes, absolutely.

DR. KRESS: Do you think it's reasonable that a same transition in break size should apply to the PWR and the BWR? It seems strange to me that they have the same 10^{-5} probably of a given size.

MR. BROWNING: Right. If you start with the premise that that's your goal, that you're trying to find an event initiating frequency in the neighbor hood of 1e to the minus 5, there's enough differences in the construction and the materials and --

DR. KRESS: And the chemistry and the --

MR. BROWNING: Exactly, but one of the things that we found difficult was that the way the rule was crafted for boilers, we would have a broad spectrum of TBS' in the boiler fleet and that kind of starts to gravitate away from this event frequency of IE to the minus 5. Some plants it would be larger, some plants it would be smaller. And we understand what the staff is saying and how they derived it but one of the things there that we kind of picked up on and we couched yesterday as plain language is the construct of the org.

There seemed to be an oversight on staff's part that all OHR piping was a single size. We tried to point out to the staff that you know, inject piping and suction piping are different sizes and then when you look at the real picture of the geometry, you end up with a TBS that skews for most BWRs in the neighborhood of the 24 inches. And what we're trying to get to is an acknowledgment in plain language if you're trying to craft a rule, that really what we're talking about is a hole. We're not trying to label any one pipe and say that's the one that's going to break. It's the feedwater pipe or it's the RHR pipe that's going to break. It's a whole and it's going to be put somewhere on the entire research system to find the worst place from the thermal hydraulics point of view.

And so if you acknowledge that we're just talking about a hole, let's not label it as a pipe of any particular name at all. Let's label it as a hole, it's a certain size and we're going to put it somewhere on the research system and let the thermal hydraulics people tell us where we get the worst PCT.

CHAIRMAN WALLACE: It reminded me of something we brought up in looking at the expert elicitation. The expert elicitation is some sort of generic BWR and surely the probability of pipes breaking depends upon the particular water chemistry at the particular plant and as well as other things which are plant specific.

MR. BROWNING: Right, there are some plant specific --

CHAIRMAN WALLACE: I'm not quite sure how we take that into account and it's a rule that applies to everybody.

DR. POWERS: Well, you have to demonstrate that the results of the elicitation are applicable to your plant.

CHAIRMAN WALLACE: You have to do that.

DR. POWERS: Yes.

DR. ARMIJO: That's built into the wording of the rule?

MR. BROWNING: It's part of the --

CHAIRMAN WALLACE: Could you take a different --

DR. POWERS: That's my understanding at any rate. That was my -- am I wrong about that? It's quite possible.

MR. BROWNING: That's actually in closer to the -- to our topical report, which is now, you know, actually more of a methodology report. The original that we submitted was trying to show in a demonstration way you know, how this rule would work, but based on staff REI, we've recrafted the topical and resubmitted it for their reconsideration of more of a methodology topical and you're exactly right, each plant has to come in and walk through a series of questions that we've tried to craft that says, "This is what I think for roughly this size of pipe what my probability of break should be for my plant based on those considerations", and then --

CHAIRMAN WALLACE: Would it say I'm closer to the mean than to the 95th percentile or something and presumably there's some flexibility in this argument.

MR. BROWNING: It would be more of a case you imply the conservatisms at the back end once you've been through that process and say, "Okay, this is where I think I am." I also consider based upon where I sit on my grid, what my switchyard configuration looks like, what I believe is my plant specific loss of outside power probability and I look at those two things on concert and look to see that I'm below a 1E to the minus 6^{th} threshold. And so once I'm down to that level, I'm in the neighborhood in an acceptable change in Reg Guide 1.174 space and then I can start taking that and saying, "Okay, now, given that, what can I do with positive changes to my plant to reduce operational burden".

And that gets into this next bullet which is you know, we've come in and tried to show to you, you know, some sensitivity to studies that we've put together on the thermal hydraulics side of it that demonstrate that there is a potential for burden reduction and diesel maintenance and other things while maintaining safety margins and defense in depth and if you'll indulge me, I'd like to point out --

CHAIRMAN WALLACE: Did this summary include power uprate or is this just to the present state of the plant?

MR. BROWNING: Really, if you look at boilers, this rule has really little or no impact on power uprate. Most of us are doing power uprates under the existing rule. We're not PCT-limited in that regard. And so my plant, for example, Dwayne Arnold is --

CHAIRMAN WALLACE: No power uprate payoff power to boilers from the new rule?

MR. BROWNING: Has little or no impact there.

CHAIRMAN WALLACE: Because this question came up yesterday.

MR. BROWNING: Except maybe for a couple of BWR 3s, I can't speak to them directly, but Dresden and Quad have already been through the EPU process and they're BWR 3s. So --

SB: What about for EBWRs, is there any potential?

MR. BROWNING: I can't speak to that.

DR. ARMIJO: They're pretty much operated as they build them. They're still not LOCA limited.

MR. BROWNING: My understanding is, no.

DR. BONACA: So could you expand a moment on the second bullet or could you tell us some examples of what you could do if you had a smaller break?

MR. BROWNING: That was one of the things we demonstrated yesterday, that as we get the transition break size down smaller, we can extend the amount of time that we use to -- for ECCS injection and that can be a combination of diesel generator start time, bringing it up to speed slowly, idle and then start loading on the major loads and also valve stroke times on the injection valves. Any combination that the plant finds beneficial in their plant.

CHAIRMAN WALLACE: But the numbers you came up with in terms of metrics for this were very small CDF changes, weren't they?

MR. BROWNING: On the CDF side of it, yeah, and --

CHAIRMAN WALLACE: And the minus 8 or 9 or something like that.

MR. BROWNING: Again, with the caveat that the way those numbers were constructed in that PRA evaluation we took a penalty at the front of 1E to the minus 6.

CHAIRMAN WALLACE: These risk benefits or these benefits that we're here about for BWRs seem to be very small in terms of risk.

MR. BROWNING: Actually, on a risk perspective they're not -- it was a surprise to us actually that they didn't come out higher when we ran them through the numbers. So we've kind of couched that more as we're risk neutral. You know, once we're allowed to do these things we're not going to have a significant negative impact on it.

And there are operational benefits for allowing us to do this, in particular increases in diesel generator reliability and less maintenance on them to maintain them to the pristine standards that they currently have to meet, to meet the stringent requirements of the double-ended guillotine break. So those are the kinds of things we were talking about yesterday. We also mentioned taking off RHR pumps from the LPSI mode and dedicating them to decay heat removal which is, we know theory is a weakness of BWRs. We've skewed our design to the double-ended guillotine break and so we have a lot of water injection capability.

But we really don't have a great deal of decay heat capability and other events like station black-out and other events in the PRA dominate because of that. And if we're allowed to move some of those pump missions from the LPSI or ECC injection capability over to shutdown, cooling or decay heat removal, we see that as a positive safety benefit.

DR. BONACA: You would have quite a significant impact on EPGs.

MR. BROWNING: Yes.

DR. BONACA: That took you years, too.

MR. BROWNING: Right, and opportunities there do exist. So, you know, we tried to take some of this ACRS' own guidance in your letter to the staff of December 17th, in '04 when you first looked at this rule of, let's try and optimize this transition break size to see how we can maximize the benefits and we've tried to look at that. And that was one of the reasons why we wanted to come in and present to you the thermal hydraulics of what we've done.

DR. APOSTOLAKIS: The safely benefits, right?

MR. BROWNING: Yes, and I think if we recrafted that topical report and didn't take the big penalty at the front end for all large break LOCA LOOPs going straight to core damage, the numbers would come up a little -- I can't -- I'm not an analyst so I can't tell you, they'd go from 1E minus 8, it would somewhere, you know, 7E to minus 7. You know, they'd get bigger. I can't tell you how much bigger. But the goal of that analysis was to show risk balance and we were trying to get to a -- we took a big penalty on one side and then we tried to incrementally work our way back up and get to risk balance.

We came close, that's why the numbers are very small. We came close.

DR. ARMIJO: In the opinion of the owners' group, does it make sense for one transition break size whether it's a pipe or a hole, to be defined for all BWRs?

MR. BROWNING: We've given that some consideration. When we made the original comment, we took it strictly from the elicitation result of if you're trying to find a break size that's with confidence and uncertainty around 1E to the minus 5, maybe one size does fit all. It really doesn't matte significantly across BWR fleet you know, what the transition break size is, you know, but it should be the same for just about everybody unless for some reason you're an outlier for another reason. You haven't implemented bar chemistry or --

DR. ARMIJO: Yeah, that's my hypothetical question. You have a plant that hasn't -- using the old normal water chemistry that BWR had done all the materials changes, they shouldn't get the same transition break size or maybe none compared to the guy who's on a more forgiving water chemistry.

MR. BROWNING: Right.

DR. ARMIJO: But --

MR. BROWNING: We would agree with that.

DR. ARMIJO: You would agree, so the question I have does it make more sense for each plant to have a transition break size that's appropriate for the plant?

MR. BROWNING: I think you could craft it in a way to where it could be, as we've suggested a series of questions about have you implemented water chemistry, you know, do you have full structural overlays or have replaced with material that's non -- as non-susceptible.

DR. ARMIJO: Get the full credit.

MR. BROWNING: Full credit right, and then you may can take a penalty off of that.

CHAIRMAN WALLACE: You might say in a realistic analysis the probabilities of pipe break should be evaluated realistically, which means that they're plant dependent and they can be evaluated that way, whichever way you do it, whether it's transition break size or through some other mechanism.

MR. BROWNING: Right, and so there's an opportunity there to again, make the rule more enabling in its language and not try to be as specific as the staff currently has crafted it and allow the reg guide to establish a process.

CHAIRMAN WALLACE: I like that idea.

DR. APOSTOLAKIS: Now, on the next slide, I don't know if you're ready to go to it, you're offering to meet with the staff and presumably with us to provide further detail on thermal hydraulic analysis and so on. So this is now the third or fourth instance where we will not have this information and yet we have to write a letter today or tomorrow.

CHAIRMAN WALLACE: We don't have to write it. We're under pressure to write a letter. We don't have to do anything.

DR. APOSTOLAKIS: Well, we are expected. We can change that but I'm beginning to think that there is a lot of information missing here for a final determination.

DR. BONACA: Also it would be interesting to know from PWR owners.

DR. APOSTOLAKIS: They are not here.

DR. BONACA: I know.

DR. APOSTOLAKIS: They must be happy.

DR. BONACA: I mean, you know, see, this information is important because --

DR. APOSTOLAKIS: Somebody must be happy.

PARTICIPANT: They're quite interested.

DR. BONACA: It gives me --

PARTICIPANT: They're very interested.

DR. BONACA: I think, we're you know at time missing a vision of what the outcome of all this may be. Now you gave us some views and I hear you. That's what I'd like to hear from PWR owners.

DR. ARMIJO: Particularly if PWRs are peak clad temperature limited, why aren't they here to say whether they can use this rule or whether this rule is going to let them --

MR. BROWNING: I think what -- I can't speak to them directly, unless John wants to as NEI.

MR. BUTLER: John Butler, NEI. The PWR owners are very interested in the rule. If you have any specific questions, I'll attempt to answer them but --

DR. APOSTOLAKIS: But do they have any complaints?

MR. BUTLER: Oh, certainly they would love to see the TBS lower than it is, but I think --

DR. APOSTOLAKIS: Not enough to come here and argue for it.

MR. BUTLER: -- what was discussed

yesterday, the limitations as opposed to break size, you go through kind of a bathtub curve and I believe the current PBS size takes you down in that trough so that you could move the TBS a little bit lower but it would not have a significant impact on the results.

MR. BROWNING: And that's one of the things, a good point on John's part, what we're trying to do as well, you know, BWR PCT versus break size curve, exhibits a similar bathtub nature. And we're trying to get the TBS down into the trough as well and because it would become less sensitive and one of the staff's concerns and the Commission's as well in this rule is that when they revisit in 10 years or whatever down the road, they don't want to see large movement in the TBS that would cause plants to have to go back outside of the back-fit rule as it's currently crafted and re-evaluate and prove again that the changes they've made continue to be acceptable with the new transition break size.

So the industry doesn't want to see the break size move around either. But if we can get it down to that trough region for both Bs and Ps, then there's a little more flexibility there. You know it can wiggle around as we gain experience with little or no impact to the operating plant.

DR. BONACA: I guess the question I have is for PWR, you know break sizes within the rule right now, you could see significant power uprates, right?

MR. BUTLER: I don't know how significant because at some point you're going to find you're limited by some other limit unrelated to LOCA.

DR. MAYNARD: That would be a concern of mine but thinking about that, right now most of the PWRs, especially later model ones and what the older ones are coming up to now, you're starting to get limited by what temperature you're actually operating RCS at, more than that large break LOCA because to get more power you're either going have to operate at a higher temperatures or increase your flow and you're not going to -- increase the flow is not a real option there.

So you're about to get to the point where you might be temperature limit on the T-hot more so than PCT at a LOCA. I don't know, I haven't given that a lot of thought.

CHAIRMAN WALLACE: And there seem to be some more things we don't know.

DR. MAYNARD: Right.

DR. BONACA: Right now they're limited either by the building because the LOCA and I am trying to understand however you know, what changes are possible in equipment that would allow them for -- anyway.

CHAIRMAN WALLACE: Can we move on with the BWR presentation? It looks like this is your final slide, the summary?

MR. BROWNING: Yes. Yeah, you know, we've had a lot of discussion in the last few days about you know, what could you do with this rule once enabled. You know, the boilers have put some thought into that. We've crafted a topical that's out for staff review, if the ACRS would -- you know, has any curiosity there, go look at it. There's a whole section on a description of the changes that we're talking about to diesel generators and augmented shutdown cooling and suppressible cooling mode, elimination of LPSI LOOPs logic in the plants that still have it. So we've kind of put some thought already into what this rule would enable use to do that would have benefit.

We'd like to leave everyone in the room, including the staff, with this idea that we're not talking about a gaping chasm between the staff and the industry over the definition of the transition break size here. You know, we're not that far apart. I think if we sit down and talk about what's important to both sides, I think we could iterate and come to an agreement of a transition break size that meets the staff's needs for conservatism and also meets the industry's needs for giving us enough flexibility to derive significant benefit to make this voluntary rule practical for us to implement.

And we're more than willing to come and to meet with the staff and to come back and make presentations to this committee to demonstrate the final resolution of that and how we arrived at it. I think you'd rather see that than come back and continue a debate in open forum over why we believe our side is right and their side is wrong.

DR. ARMIJO: Well, I'd like to see a justification for your position. You know, the -- particularly the fundamental reason of why you think the piping with the mitigation work that's already been done, is much more reliable than what the staff believes. To me, that's a key question.

DR. APOSTOLAKIS: What is the schedule here?

MR. DUDLEY: The current schedule on the

rulemaking is to provide a final rule to the Commission in the end of February 2007. That's the current schedule.

CHAIRMAN WALLACE: But the real purpose is to come up with the right rule --

DR. APOSTOLAKIS: Absolutely.

CHAIRMAN WALLACE: == if you have not come up with a rule at all. This is a long-term issue and it would seem to me that the schedule is not the driving force. The driving force is doing the right thing on something which could have a big significance for the industry and the future of nuclear power and the public perception and everything.

DR. APOSTOLAKIS: Mr. Browning was saying that even if we do what he proposes it will not delay the Schedule, right, the last sub-bullet there, "maintain NRC schedule"?

MR. BROWNING: We're willing to get on a plank.

DR. APOSTOLAKIS: The problem is that 11 of us have to do the same thing.

DR. SHACK: I turn it back to you, Mr. Chairman. Thank you very much.

CHAIRMAN WALLACE: Well, I -- thank you

very much. We're going to take a break. Before we do so, I would like to say that I, at least as the Chairman, was impressed by the resilience and openness of the replies by the staff and the -- and by the other owners groups to what I think were very important questions raised by the committee. Thank you very much for that.

We'll take a break until 4:00 o'clock.

(Whereupon, a short recess was taken.)

CERTIFICATE

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

Name of Proceeding: Advisory Committee on Reactor Safeguards 537th Meeting

Docket Number: n/a

Location: Rockville, MD

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.

Charles Morrison
Official Reporter
Neal R. Gross & Co., Inc.

BWROG Positions on the 10 CFR 50.46a Rulemaking

Tony Browning, BWROG Option 3 Committee Chair
ACRS Meeting
November 1, 2006

1

Summary of Positions

- BWROG pleased that this initiative has proceeded to a draft rule
- Unlikely that rule as written would be implemented by any BWRs because the cost to implement would outweigh the small benefit
- There is unnecessary conservatism in NRC staff selection of TBS apparently based on incomplete assessment of IGSCC, FAC, and thermal fatigue mitigation
- New T/H analysis demonstrates potential for burden reduction while maintaining safety margins and defense-in-depth

2

Summary of Positions

- Related BWROG LTR on separation of LOOP from LOCA requirements provides details on plant enhancements that would be useful
- Only minor changes to TBS selection in the proposed rule would significantly enhance its usefulness to BWRs
- BWROG prepared to meet with staff at an early date to
  - Provide further detail on T/H analysis and mitigation of materials issues to arrive at acceptable TBS that is also useful to BWRs
  - Maintain NRC schedule for rule completion

3

10 CFR 50.46a Rulemaking Risk-Informed ECCS Requirements

Advisory Committee on Reactor Safeguards

November 1, 2006
Richard Dudley
Rulemaking Project Manager
Division of Policy and Rulemaking
Office of Nuclear Reactor Regulation

10 CFR 50.46a Rulemaking

Request for ACRS Letter on Final Rule

- Staff seeks ACRS review of issues related to the §50.46a final rule
- Potential impact of pipe crack indications at Wolf Creek plant has caused staff to review its position on seismic analysis supporting the PWR TBS
- Staff will inform the ACRS when Wolf Creek review is completed and meet with Committee if significant changes result

10 CFR 50.46a Rulemaking

Agenda

- Discuss method for selecting BWR TBS (G. Hammer)
- Discuss comments related to risk analysis and operational requirements (S. Dinsmore)

3

BWR TBS Selection

- BWR TBS in the proposed rule uses expert elicitation estimates of LOCAs at 1E-5/R-Y frequency as a starting point.
- Adjustments made to account for uncertainties and sensitivities with respect to elicitation.
- Other considerations to accommodate failure mechanisms not explicitly considered in elicitation such as seismic loads.
- Consideration of actual pipe sizes.
- Consideration of regulatory stability.

4

BWR TBS Selection

- From the expert elicitation estimates, also considering uncertainties and sensitivities, BWR break sizes at a 1E-5 frequency are approximately 13 inches to 20 inches in diameter.
  - Considers 95th percentile estimates.
  - Considers geometric and arithmetic mean aggregations of estimates.

5

BWR TBS Selection

- These sizes are approximately the sizes of the largest attached feedwater and residual heat removal lines inside containment, typically 18 to 24 inches nominal diameter (or 16.12 to 21.56 inches ID).
- Breaks larger than these in size would require complete failure of large recirculation piping, which has a significantly lower frequency of occurrence.

6

10 CFR 50.46a Rulemaking
Major Public Comments

Advisory Committee on Reactor Safeguards

November 1, 2006

Stephen Dinsmore
Senior Reliability and Risk Analyst
Office of Nuclear Reactor Regulation

10 CFR 50.46a Rulemaking
Major Public Comments

Summary of Major Public Comments on Risk informed Change process

- Scope of facility changes requiring a risk evaluation
- Identification of changes that require prior staff review and approval
- Tracking risk increases
- Periodic PRA update and reporting
- Acceptance criteria on amount by which risk increases
- Operational restrictions / maintaining mitigation

8

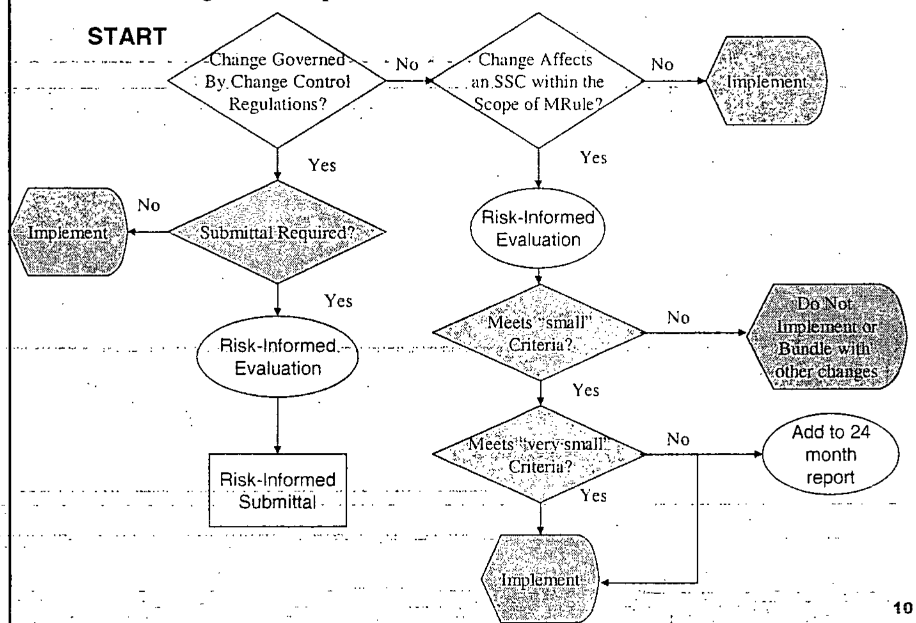
10 CFR 50.46a Rulemaking Major Public Comments

Issue: Scope of facility changes requiring a risk evaluation

- Proposed rule: A risk evaluation of all changes is required prior to implementing the change
- Comment: Does not credit current change control processes and is unnecessarily burdensome
- Final Rule: A risk evaluation is required prior to implementing potentially risk-significant changes. A periodic risk evaluation is required to assess the cumulative effect of all changes

9

50.46a Change Control process



10

10 CFR 50.46a Rulemaking Major Public Comments

Issue: Identification of changes that require prior staff review and approval

- Proposed rule: Current regulatory requirements and any change that increases risk by more than a "very small" amount govern what must be submitted for prior staff review and approval.
- Comment: Does not credit current change control processes and is unnecessarily burdensome.
- Final Rule: Current regulatory requirements govern which changes must be submitted for prior staff review and approval.

11

10 CFR 50.46a Rulemaking Major Public Comments

Issue: Tracking risk increases

- Proposed rule: The amount by which CDF and LERF increase over time must be estimated and tracked.
- Comment: It should be sufficient to estimate and track the overall CDF and LERF over time.
- Final Rule: Unchanged

12

10 CFR 50.46a Rulemaking Major Public Comments

Issue: Acceptance criteria on amount by which risk increases

- Proposed rule: The amount by which CDF and LERF increase is compared to the acceptance criteria that the "total increases in CDF and LERF are small and the overall risk remains small." Small is defined using RG 1.174 guidelines.

- Comment: Do not put acceptance criteria in the rule and rely on RG 1.174 guidelines for controlling risk increases over time.

- Final Rule: Unchanged

13

10 CFR 50.46a Rulemaking Major Public Comments

Issue: Periodic PRA update and reporting

- Proposed rule: PRA update every two refueling outages and reporting of
  - Changes that result in a "significant reduction in the capability to meet the acceptance criteria" and
  - Short description of all changes involving minimal increases in risk

- Comment: Industry proposed PRA update every two refueling outages to assess the cumulative effect of changes and reporting of the results (i.e., overall CDF and LERF) of this assessment to the NRC.

- Final Rule: PRA update every two refueling outages and reporting of
  - Steps and a schedule to bring the facility back into compliance if the acceptance criteria have been exceeded and
  - Potentially risk-significant changes implemented without NRC review that increased risk greater than very small

14

10 CFR 50.46a Rulemaking Major Public Comments

- Issue: Operating restriction when in a configuration not demonstrated to meet the ECCS acceptance criteria for breaks>TBS
  - Proposed rule: Prohibited operation in this configuration.
  - Public Comment: Restriction not commensurate with safety significance of configuration and could increase risk by reducing permitted on-line maintenance.
  - Final Rule: Operation in this configuration not to exceed 14 days per year. Fourteen days was chosen as
    - Consistent with related guidelines on initiating event mitigation
    - Sufficiently long to allow most maintenance activities
    - A longer period of time would not be consistent with maintaining the capability to successfully mitigate the full spectrum of LOCAs

15

10 CFR 50.46a Rulemaking Major Public Comments

Issue: Operational Restrictions (Cont.)

- No guidance directly addressing this issue exists but some related guidance does exists
- RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications "
  - Acceptance guideline for integrated conditional core damage probability <= 5E-7
  - 1E-5/year frequency with no LOCA mitigation yields an allowed AOT of 18 days
- SRP Chapter 2.2.1 and 2.2.2 identifying design basis events (that need to be mitigated) as those with a frequency >1E-7/year
  - 1E-5/year frequency could exist for 3.6 days in a one year period before exceeding an annual frequency of 1E-7

16

10 CFR 50.46a Rulemaking Major Public Comments

Miscellaneous

Risk-Informed change process description should not be required with submittal to adopt 50.46a

The acceptability of many changes, including some without prior staff review and approval, will be based, in part, on the results of the risk-informed evaluation. Without opportunity to review a description of the proposed process, the staff would have no basis for concluding the process is capable of demonstrating the acceptance criteria are satisfied

Deletion of requirement for LOOP and single failure for > TBS could result in all EDGs being required to mitigate a LBLOCA/LOOP.

The risk increases arising from such changes must be evaluated and, if acceptance criteria are exceeded, the change would not be permitted or must be otherwise compensated.

17

DRAFT REGULATORY GUIDE DG-1170 FOR FIRE PROTECTION FOR NUCLEAR POWER PLANTS AND SRP SECTION 9.5.1 UPDATES

ADVISORY COMMITTEE FOR REACTOR SAFEGUARDS

OCTOBER 31, 2006

Bob Radlinski
Fire Protection Engineer
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Significant Changes to RG

- Guidance/acceptance criteria for new reactor FPP's
- Added new guidance based on recently issued generic communications
  - RIS 2005-30, "Clarification of Post-Fire Safe-Shutdown Circuit Regulatory Requirements"
  - RIS 2006-10, "Regulatory Expectations with Appendix R Section III.G.2 Operator Manual Actions"
- Added new guidance on post-fire safe-shutdown circuit analyses and multiple spurious actuations
- Replaced GL 86-10 evaluations with 50.59 for FPP changes for new reactors
- Added guidance on use of fire PRA and fire modeling
- Added/clarified fire protection term definitions

Guidance/Criteria for New Reactor FPP's

- Enhanced fire protection criteria approved by Commission
- Applicability of industry codes, including NFPA 804
- Passive plant shutdown definition
- Fire Protection Program implementation

Guidance/Criteria for New Reactor FPP's (Cont)

- Minimize reliance on the following:
  - Alternative/dedicated shutdown systems (except for control room fires)
  - Operator manual actions
  - Local electrical raceway fire barrier systems
- Should not rely of self-induced SBO for post-fire safe shutdown
- Address fire protection for non-power operations

Guidance Based on Recently Issued Generic Communications

- RIS 2005-30, "Clarification of Post-Fire Safe-Shutdown Circuit Regulatory Requirements"
  - Post-fire safe-shutdown circuit analyses must consider any-and-all hot shorts and spurious actuations
  - "Associated circuits" means all circuits that must remain free of fire damage, except with respect to alternative/dedicated shutdown systems

Guidance Based on Recently Issued Generic Communications (Cont)

- RIS 2006-10,"Regulatory Expectations with Appendix R Section III.G.2 Operator Manual Actions"
  - Operator manual actions may not be credited in lieu of required III.G.2 protection (without an approved exemption)
  - Where III.G.2 protection is provided for one redundant train, OMAs are permitted for the unprotected train

Guidance on Multiple Spurious Actuations

- Post-fire safe-shutdown circuit analyses should address multiple spurious actuations
- Spurious actuations may occur in rapid succession without time to mitigate the consequences
- A one-at-a-time approach to evaluating multiple spurious actuations does not comply with fire protection regulatory requirements

50.59 FPP Change Evaluations

- GL 86-10 allowed licensee self approval of FPP changes based on "no adverse effect on safe shutdown" and in accordance with 10 CFR 50.59
- NEI persuaded NRC to exclude fire protection from 50.59 rule in 2000
- Staff is proposing to revert to 10 CFR 50.59 as applicable to FPP changes- for new reactors only
- Reverting to 50.59 brings fire protection in line with the rest of the plant; provides a more definitive set of acceptance criteria; and provides a regulatory requirement for documenting the bases for changes.

Use of Fire PRA and Fire Modeling

- Added guidance consistent with that in RG 1.205 for NFPA 805 plants
- Proposed that PRA methodologies for use at non-805 plants should be submitted for NRC review and approval
- Fire models should be those accepted by the NRC (or submitted for review)
- Reference NUREG/CR-6850 and the draft American Nuclear Society Fire PRA Standard as the basis for review of PRA methodologies

Previously Undefined Fire Protection Terms

- Added/clarified definitions for fire protection terms that are not currently well defined in regulatory documentation
- Definitions are based on regulatory requirements, staff positions and common usage
- Newly defined or clarified terms include any-and-all, emergency control stations, fire protection system, mitigate, one-at-a-time, operator manual action, post-fire safe-shutdown circuits, redundant train/system, and success path.

Significant Changes to SRP 9.5.1

- Deleted Branch Technical Position – incorporated in RG 1.189 update
- Expanded review guidance for new reactors
- Added reference to new SRP section for NFPA 805 plants
- Provided review guidance for fire modeling and PRA methodologies in licensee submittals (non NFPA 805 plants)
- Expanded review guidance for license renewal applications
- Expanded the References section

Deleted Branch Technical Position

- Incorporated BTP guidance into RG 1.189 update
- Much of the BTP guidance was already included in the original issue of RG 1.189
- RG 1.189 is identified in SRP 9.5.1 as providing acceptance criteria for reviews

Expanded Review Guidance for New Reactors

- Provided risk insights for new reactor fire protection programs
- Added review guidance for ITAAC, COL applications, programmatic features of FPP
- Identified review interfaces
- Referenced DG-1145
- Expanded guidance for reporting evaluation findings

Expanded Review Guidance for New Reactors (Cont)

- Added new references applicable to new reactors
- Added guidance for fire protection systems that provide backup to safety related systems
- Identified alternative designs that have been accepted by the staff
- Provided guidance for review of fire protection systems protecting areas that do not contain safety-related SSCs

Other Changes to SRP 9.5.1

- Deleted Appendix A: "Supplemental Fire Protection Review Criteria for Shutdown and Decommissioned Reactors" (this guidance is provided in RG 1.191)
- Updated guidance on the use of fire modeling and probabilistic methodologies for non-NFPA 805 plants
- Added reference to new SRP section for NFPA 805 plants
- Expanded review guidance for license renewal applications

Palisades Nuclear Plant
License Renewal Safety Evaluation Report

Staff Presentation to the ACRS

Juan Ayala, Project Manager
Office of Nuclear Reactor Regulation
November 1, 2006

Introduction

- Overview
- Highlights of the Review
- Time-Limited Aging Analyses (TLAAs)
- Conclusion

Overview

- LRA submitted by letter dated March 22, 2005
- CE PWR-DRYAMB containment
- 2565 MWth, 820 MWe_{net}
- Operating License DRP-20 expires March 24, 2011
- PNP located 5 miles S of South Haven, MI

Overview

- Initial SER issued June 1, 2006
  - No Open Items, One Confirmatory item
- 174 RAIs issued, 412 audit questions
- 95% consistent with GALL, Revision 1
- Final SER issued September 28, 2006
  - 55 commitments
  - 3 license conditions

Review Highlights

- Three (3) license conditions
  - FSAR to be updated following issuance of the renewed license
  - Commitments completed in accordance with the schedule in Appendix A of the SER and tracked in the FSAR
  - Reactor Vessel Surveillance Program
    - All capsules placed in storage must be maintained for future insertion
    - Any changes to storage requirements must be approved by the NRC

Review Highlights

- AMP GALL Audit
  - June 20 - 24, 2005
- Scoping and Screening Methodology Audit
  - June 27 - July 1, 2005
- AMR GALL Audit
  - August 1 - 5, 2005
- Regional Inspections
  - October 24 - 28, 2005
  - November 14 - 18, 2005

Review Highlights

- The applicant's scoping methodology meets the requirements of 10 CFR Part 54
- Scoping and screening results, as amended, included all SSCs within the scope of license renewal and subject to AMR
- Items brought into scope and subject to AMR
  - AFW Pump Room pipe insulation
  - Steam generator feedwater ring
  - Boric acid pump filters
  - Air supply line and air reservoirs
  - Solenoid valves
  - Primary system make-up storage tank
  - Feedwater heaters
  - Containment sampling pumps
  - Moisture separators

Aging Management of In-Scope Inaccessible Concrete

	Acceptance Criteria	PNP		
		1966	1996	2004
pH	>5.5	6.1 - 7.7	N/A	7.0
Chlorides	<500 ppm	4.0 - 39	23	139
Sulfates	<1500 ppm	9.47 - 33.17	15.2	11.5

- Below-grade environment is non-aggressive
- Periodic testing of ground water will be performed as part of the Structures Monitoring Program

Small Bore Piping Welds

- One-time inspection program
  - One-time volumetric examinations of a 10% sample of Class 1 butt welds, nominal pipe size (NPS) 4-inch and smaller
  - 100 percent VT-2 examinations of all Classes 1 and 2 high safety significance socket welds NPS 2-inch and under during each refueling outage.
  - Performed within last 5 years of current operating period.

Section 4 - Review Highlights

- Section 4.2: Reactor Vessel and Internals Neutron Embrittlement
  - Three analyses affected by irradiation embrittlement identified as TLAAs
    - Pressurized Thermal Shock
    - Upper Shelf Energy
    - Pressure Temperature Limits
- Applicant used 42.37 EFPY (60 years)

Section 4 - Review Highlights

- RV Pressurized Thermal Shock

Limiting Material for PTS	Screening Criteria	Calculated 42.37 EFPY RT_{PTS} value	Conclusion
Intermediate shell and lower shell axial welds (W5214)	270 °F	Applicant: 287 °F (Calculation Confirmed by Staff)	Screening Criterion is exceeded in 2014

Section 4 - Review Highlights

- Palisades Plan for PTS
  - Continue to use an ultra low leakage core design
  - Submit final PTS resolution three years before 2014 (10 CFR 50.61)
- Options
  - Change of operation: further flux reduction and preheating the safety injection water
  - Thermal annealing of the reactor pressure vessel (10 CFR 50.66)

Section 4 - Review Highlights

- RV Upper Shelf Energy (USE)

Limiting Plate and Weld for USE	Acceptance Criterion	Calculated USE Value for 42.37 EFPY	Conclusion
Lower shell plate (D-3804-1)	Projected USE > 50 ft-lbs	48.97 ft-lbs (Calculation Confirmed by Staff)	Acceptance criterion is exceeded in 2021
Intermediate to lower shell circ. Weld (9-112)	Projected USE > 50 ft-lbs	50.83 ft-lbs (Calculation Confirmed by Staff)	Acceptable [TLAA satisfies §54.21(c)(1)(ii)]

Section 4 - Review Highlights

- Palisades Plan for USE
  - Submit Equivalent Margins Analysis (EMA) three years before 2021 (10 CFR 50, Appendix G)

Section 4 - Review Highlights

- Pressure-Temperature Limits
  - Limits estimated to expire in 2014

- Palisades Plan for P-T limits and LTOP Curves
  - Applicant will update and submit P-T limits and LTOP curves prior to entering PEO
  - Technical Specifications will be updated
  - Will be managed by the Reactor Vessel Integrity Surveillance Program

Reactor Vessel Underclad Cracking

- Confirmatory Item: Underclad Crack Growth
  - WCAP-16605-NP
    - Plant-specific version of WCAP-15338-A
    - Includes plant design transients
    - Bounding nature of the analysis in WCAP-15338-A also applies to PNP
  - Flaw evaluation demonstrates that after 60 years of fatigue crack growth, significant margins remain for underclad flaws
  - Staff concerns are resolved

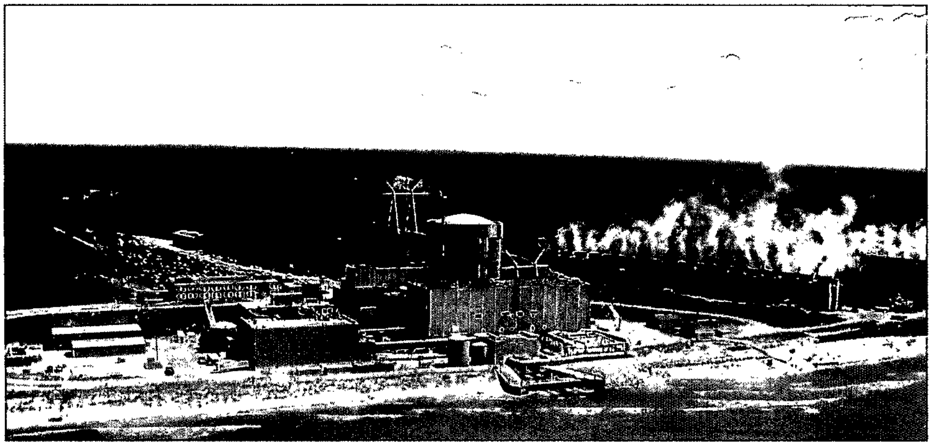
Conclusions

- The staff has concluded that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB
- Any changes made to the PNP CLB are in accord with the Act and the Commission's regulations and to comply with 10 CFR 54.29(a)

Questions

Palisades Nuclear Plant

Presentation to Advisory Committee on Reactor Safeguards



November 1, 2006

Consumers Energy Count on Us

NMC Committed to Nuclear Excellence

Participants

- Paul Harden – Site Vice President
- Bob Vincent – License Renewal Project Manager
- Mark Cimock – Mechanical and Civil/Structural Lead
- Larry Seamans – Electrical Lead
- Bill Roberts – Programs Lead
- John Kneeland – TLAA Lead
- Brian Brogan – Site PRA / Safety Analysis Lead

Agenda

- Plant Description & Current Status
- Plant Modifications / Improvements
- License Renewal Project
- Technical Issues
  - Intergranular Separation
  - Pressurized Thermal Shock

Plant Description

- Owned by Consumers Energy Company
- Operated by Nuclear Management Company
- 432 Acre Site Located in Covert, Michigan
- Combustion Engineering NSSS / Bechtel AE
  - 2 Loops, 2 Steam Generators, 4 Primary Coolant Pumps
- Licensed Power 2565.4 Mwt.
- License expires March 24, 2011

Plant Description

- Pre-Stressed Concrete Containment
- Forced Draft Cooling Towers
- Ultimate Heat Sink is Lake Michigan via Service Water System
- Design Reviewed in NRC Systematic Evaluation Program
- Plant PRA Shows CDF (Internal Events) of 2.5E-05/yr; LERF 3.55E-7/yr

Current Plant Status

- Running Well at 100% Power in 19th Cycle – 170 days on line
- Next Refueling Outage Fall 2007
- All 3Q NRC Performance Indicators are Green
- No NRC Inspection Findings >Green

Major Plant Modifications/Improvements

- 1974-75 – Converted Once-Through Circulating Water to Cooling Towers, Retubed Condenser
- 1983 – Added Third Auxiliary Feedwater Pump and Upgraded System to Safety-Grade
- 1983 – Upgraded Control Room HVAC to Safety-Grade
- 1989 – Diversified Connection Paths to Offsite Power Supplies (PRA Insight)

Major Plant Modifications/Improvements

- 1990 – Replaced Steam Generators, Retubed Condenser and Feedwater Heaters
- 1993 – Implemented Dry Spent Fuel Storage
- 1995 – Modified Under-Reactor Vessel Floor Drains to Containment Sump (PRA Insight)
- 2003 – Implemented Risk-Informed Inservice Inspection Program
- 2006 – Installed Non-Safety Backup Diesel Generator (SAMA/PRA Insight)

License Renewal Project

- Staffed with Plant-Experienced Leads and LR-Experienced Support
- LRA Prepared to NEI 95-10 Standard Format Using GALL Rev 0 (2001)
- AMR Results Compared to GALL Rev 1 (2005)
- 24 Aging Management Programs (4 new, 20 existing)
- Program Descriptions, TLAA Descriptions, and Commitments will be Incorporated Into FSAR
- Project Team Continuing With Implementation

Technical Issues

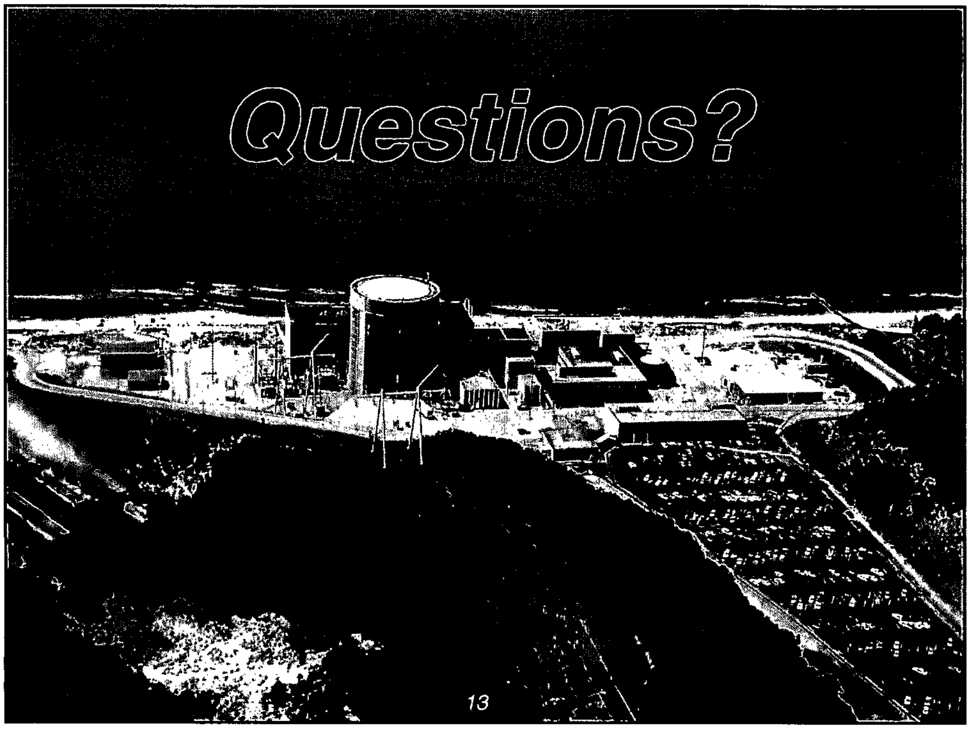
- Intergranular Separation
- Pressurized Thermal Shock

Intergranular Separation
(Under-Clad Cracking)

- Generic Industry Question in 1970s – Acceptable for 40 Years
- Westinghouse Evaluated for 60 Years in WCAP-15338 (NRC Accepted Methodology and Results)
- Palisades Evaluated Using Same Methodology
- Palisades Results Consistent with WCAP-15338
  - Little/No Growth Over 60 Years
  - No Effect on Structural Integrity
- Results Accepted by NRC

Pressurized Thermal Shock (PTS)

- Reach 10 CFR 50.61 Screening Criterion in 2014
- Aggressive Flux Reduction Implemented by Ultra-low Leakage Core Design
- Participant in NRC Research Program Developing Updated Technical Methodology
- Alternatives are Available to Manage Issue for Period of Extended Operation
- Proposed 10 CFR 50.61 Rule Change may Preclude Need for Plant-Specific Management Strategy



Backup Slides

Consumers Energy
Count on Us

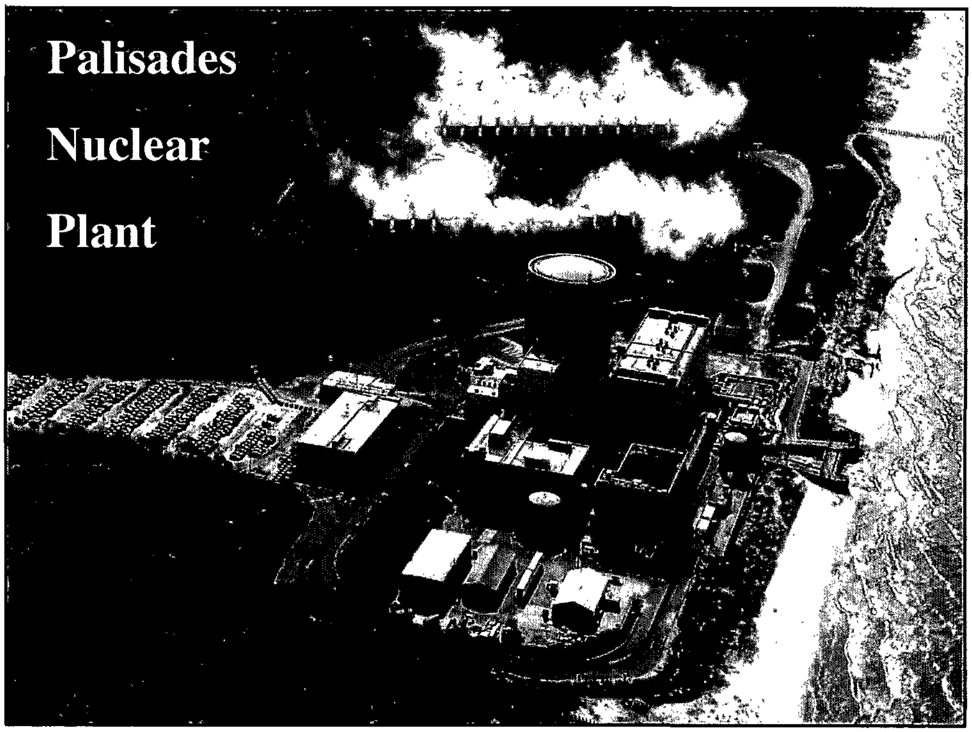
NMC
Committed to Nuclear Excellence

Inspection of Small-Bore Piping

- RI-ISI Examines Selected Small-bore ASME and Non-ASME Class Piping
  - 4 Class 1 HSS Butt Welds Examined Volumetrically Each 10 Year Interval
  - 100% HSS Socket Welds Examined VT-2 Each Cycle
- Small-bore Class 1 Weld Population - 60 Butt Welds and 359 Socket Welds
- For License Renewal, 10% of Class 1 Butt Welds will be Volumetrically Examined as One-Time Inspection prior to Extended Operating Period

Possible Strategies for Management of PTS

- Exemption Based on Master Curve Technology for Determining Fracture Toughness
- Change to 10 CFR 50.61 (Rulemaking Initiated)
- Safety Analysis (R.G. 1.154) to Evaluate Actions That Would Assure Reactor Vessel Integrity during PTS if Continued Operation Permitted
  - e.g., Heating of Safety Injection Water
- Annealing
- Further Flux Reduction


Palisades
Nuclear
Plant