Official Transcript of Proceedings ACRST-3331

NUCLEAR REGULATORY COMMISSION

ORIGINAL

Title: Advisory Committee on Reactor Safeguards
Subcommittee on Power Uprates

Docket Number: (not applicable)

PROCESS USING ADAMS
TEMPLATE: ACRS/ACNW-005

SISP - REVIEW COMPLETE

Location: Brattleboro, Vermont

Date: Wednesday, November 16, 2005

Work Order No.: NRC-730 Pages 1-374

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

November 16, 2005

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE ON POWER UPRATES

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WEDNESDAY,

NOVEMBER 16, 2005

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The meeting came to order at 8:28 a.m. at the Quality Inn and Suites, in Brattleboro, Vermont. Dr. Richard Denning, Chairman, presiding.

PRESENT:

RICHARD DENNING, Ph. D., CHAIRMAN

MARIO BONACA, Ph. D., MEMBER

THOMAS KRESS, MEMBER

VICTOR RANSOM, Ph. D., MEMBER

JOHN SIEBER, MEMBER

GRAHAM WALLIS, Ph. D., MEMBER

ALSO PRESENT:

GEORGE APOSTOLAKIS
SANJOY BANERJEE
RALPH CARUSO
LARRY DOERFLEIN
RICK ENNIS
BRIAN HOBBS
SARAH HOFMANN
CORNELIUS HOLDEN
GRAHAM LEITCH
RICHARD LOBEL
JEFF JACOBSON
DAVID O'BRIEN
MARK PALIONIS
MARK RUBIN
BILL SHERMAN
BETH SIENEL
BRUCE SLIFER
ASHOK THADANI
CHRIS WAMSER

A G E N D A

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

(8:28 a.m.)

CHAIRMAN DENNING: The meeting will now come to order. This is a continuation of the meeting that began yesterday of the Advisory Committee on Reactor Safeguards, Subcommittee on Power Uprates. I am Dr. Richard Denning, Chairman of the Subcommittee. The committee members in attendance today are Dr. Graham Wallis, Dr. Tom Kress, Dr. Victor Ransom, Mr. Jack Sieber, Dr. George Apostolakis, and Dr. Mario Bonaca. ACRS consultants in attendance are Dr. Sanjoy Banerjee, Mr. Graham Leitch.

The purpose of this meeting is to discuss the extended power uprate application for the Vermont Yankee Nuclear Power Station. The subcommittee will hear presentations by and hold discussions with representatives of the NRC Staff and the Vermont Yankee Licensee, Entergy Nuclear Northeast, and also from the Vermont Department of Public Service regarding these matters.

The subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the Full Committee. Ralph Caruso is the Designated Federal Official for this meeting.

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the "Federal Register" on November, 2004. A transcript of the meeting is being kept and will be made available as stated in the "Federal Register" notice. It is requested that speakers first identify themselves and speak with sufficient clarity and volume so that they can be readily heard. We request that members of the audience refrain from talking so that the presentations can be heard by everyone who is here today. We all want this meeting to be as productive as possible, so I would encourage everyone who is here today to listen carefully to all of the presenters and speakers.

We have received several requests from members of the public to make oral statements at this meeting. In addition, to accommodate members of the public who were not able to contact the ACRS Staff in advance, we've set up a sign-up list at the table at the entrance to the room for this afternoon's public comment session. As yesterday, we will take speakers one at a time from the list until the close of the business at 5:30 p.m. If time does not allow us to hear all of the people who wish to speak, they can submit written comments to the ACRS at the NRC's Washington, D.C. address, or by email to Mr. Caruso at the address on the agenda.

This is the first of two ACRS Subcommittee meetings that will consider the Vermont Yankee Power Uprate request. On November 29 and 30, the Subcommittee will meet at NRC Headquarters in Rockville, Maryland to hear presentations regarding other technical subjects, including some that involve proprietary information. That meeting will also be open to the public, except for those portions during which proprietary information will be discussed. The Full ACRS is scheduled to consider this application on December 7, 2005 in Rockville, Maryland, and that meeting will also be open to the public. I understand that the press release that announced today's meeting also stated that the Full Committee meeting would be held on December 8th, but please note that that meeting has been moved up one day to accommodate the meeting of the ACRS with the Commissioners.

We will now continue with the meeting, and I call upon Mr. Bill Sherman to begin. Thank you.

MR. SHERMAN: Thank you, Dr. Denning, members of the committee, consultants, and staff. I'm Bill Sherman. I'm the State Nuclear Engineer for the

State of Vermont located in the Vermont Department of Public Service. I would first like to introduce Commissioner David O'Brien, Commissioner of the Department of Public Service, to say a few words.

COMMISSIONER O'BRIEN: Good morning, gentlemen. I actually want to be very, very brief. I want to make sure that we save the time for Mr. Sherman's presentation, and certainly for whatever questions you might have of him. I simply just want to express our appreciation and our gratitude for you to come here to Vermont, and to Brattleboro to conduct this meeting at, I guess, our suggestion, but I think in your own good judgment, and to hear from the public yesterday. I understand the meeting went quite long yesterday, and you gave people a lot of chance to offer their concerns, or their comments, or pose questions and that sort of thing, and we tried our level best to do that here, state representing the public and the State of Vermont. I chair what's called the Vermont State Nuclear Advisory Panel. We've held numerous meetings in this part of the state, and sometimes with NRC Staff providing information to the public, so I very much appreciate you taking that time and that effort.

I think we feel very good about what Bill will be presenting to you this morning. We've put a lot of effort into our role in terms of looking at the safety of this facility. It's very, very important to us. This is a very important facility to us from a power standpoint, that that cannot be understated how important this facility is to the State of Vermont from a power supply standpoint, and from an economic standpoint. We simply are in pursuit of what we hope is a safe operation of that plant, and I think that, again, may sound simplistic to say, but that's an important part of your role, certainly. So I look forward to hearing your questions today and the other presentations, and I just want to say that on behalf of Governor Douglas and the State of Vermont, we very much appreciate you taking the time out of your busy lives to come here and conduct this hearing in Vermont. Thanks.

MR. SHERMAN: I would also like to introduce who are with us today; Sarah Hofmann, who is the Vermont Director of Public Advocacy, and Mr. Anthony Royceman, who is also an attorney, working for us and the state.

We appreciate very much the opportunity to speak today on containment over-pressure, and especially we appreciate adjusting the agenda so that we could speak in this first slot this morning. We presented on the subject to the Thermal Hydraulic Subcommittee in July of this year, and to the Full Committee in September on a generic issue related to the same subject, and Regulatory Guide 1.82. In Vermont, we have high confidence in this committee and its deliberations to help us consider and assist us in resolving our concerns on this issue.

I'm not going to say so much about the technical aspects of containment over-pressure because I trust that the slides and presentation from the licensee and the staff will say more, and I know the committee is familiar with the issue.

In Vermont, we question the desirability of using containment pressure to demonstrate the adequacy of emergency cooling pumps. When we started out the power uprate review, we wrote a letter to the staff in December of 2003 because it appeared to us that the staff wasn't following its own guidance in Regulatory Guide 1.82 Revision 3. As we passed on, we found that we did not have answers to our questions, and so we initiated an Atomic Safety and Licensing Board proceeding which is ongoing. We continue to have questions, although we feel that this process is assisting us to get the answers to our questions.

What I will do in my presentation is first identify and summarize the letter that the committee wrote in September. Following that, I will identify some aspects of Vermont Yankee's application as it relates to the letter. Then I will summarize Dr. Sheron's presentation that he made to the Full Committee in October, the licensee's response to that. I will identify some comments that we have on the licensee's response to Dr. Sheron's proposal, and then comment at the end of the presentation about the overall method of that proposal and the probabilistic safety assessment method to look at this problem. And I wanted to go first, wanted to have the state go first so that we would have the opportunity for both the licensee and the staff to, perhaps, answer some of the questions and issues that we propose.

I would be remiss if I tried to propound that we were experts in probabilistic safety assessments; we're not. We've reviewed their material, we have some comments. They may be able to provide comments that resolve the questions and concerns we have.

In the letter of September 20th of this year, the committee stated that, "For containment over-pressure there should be no practical alternatives that can eliminate the need for such credit." They indicated it would be useful for positive means of indication of containment integrity that the time intervals for such credit should be limited to a few hours commensurate with the demonstrated capability of equipment to perform its intended functions during this time period.

I'm showing now what is Vermont Yankee's proposal. This is part of their submittal. I don't believe this particular slide or figure was included in the Safety Evaluation Report, but a table with essentially the same information was in the SER.

This shows that they need containment over-pressure for the period shown here for both the containment spray pump and the residual heat removal pump. It shows that they calculate containment pressure to be over what they need. It requests step increases and decreases of containment pressure as credit.

I took the liberty of putting the time scale on the bottom here, and only because when time is shown in seconds, it's not as easy to see. It shows easier in hours, although we all know, we can all do the math. They're asking for credit for the RHR pumps for up to 56 hours.

MEMBER WALLIS: While we're looking at this figure, this over-pressure available, that is presumably a conservative estimate. It's actually higher than that. Is that what I understand, or is that a best estimate curve? Which is it?

MR. SHERMAN: No, Dr. Wallis, or the answer; yes, Dr. Wallis, that is a conservatively calculated pressure, where all of the assumptions that go into it have been either minimized or maximized to give the lowest pressure possible. And in the State of Vermont, we accept that. We don't question that that's a conservative calculation. And for containment integrity for the pressure retention, the maximum pressure curve is, I think, up in the high 20s or 30s.

So as I was saying, they're asking for over-pressure credit for the HRH pumps for approximately 56 hours. Just looking on the curve, it looks like 40-41 hours of credit necessary for the containment spray pump.

Now in terms of the first item in your letter of September, practical alternatives, we found in our review that the staff, I don't believe, has even yet formally inquired about practical alternatives. I don't think there was a request for additional information, RAI, related to practical alternatives. And it wasn't until just last month that Entergy volunteered some information in Supplement 38 regarding practical alternatives, I think as a result of your letter in September.

What they said was that they had not completed looking at alternatives, that changes would be quite substantial, that a new pump design would be required. In their supplement they provided a list of design implications that would result from implementing a practical alternative. They indicated that effectively it would double the length of a refueling outage, or in the alternative, it might be necessary to implement over several refueling outages.

From our point of view, it appears that Entergy's objections to alternatives appear to translate into costs. We believe, and actually we think that the law says that safety issues should not be cost-driven. And we also think that there is significant economic value to Entergy in the proposed uprate.

MEMBER WALLIS: So there's no estimate of the cost of this at all yet. Is that right?

MR. SHERMAN: No estimate of the cost of what?

MEMBER WALLIS: Of any of these alternatives.

MR. SHERMAN: We are not aware of the estimate of the cost of any of these alternatives.

Commenting on the other items in the ACRS letter, in terms of positive indication of containment integrity, the letter itself notes inerting, although we're not sure that inerting is an effective indicator of containment integrity because the inert system at Vermont Yankee is a feed and bleed system, which means that they are constantly feeding Nitrogen, and they're constantly bleeding Nitrogen. And the very fact that it's inerted by itself doesn't indicate that you have containment integrity.

However, the drywell is maintained at a positive pressure, 1.7 psi above the suppression pool. We do believe that that's an indication that the drywell maintains pressure.

MEMBER KRESS: Do you have an idea what the amount of the feed and bleed there is; that would be an indicator.

MR. SHERMAN: The licensee could answer that. But through our review, here's what I think. I believe that for the drywell maintained at positive pressure but with a feed and a bleed system, they can indicate whether they get a significant additional leakage, and that the leakage of the drywell in the feed and bleed system is much less than would defeat containment pressure. I'm not sure that they have that indication with the Torus because the Torus is essentially at atomospheric pressure, and I'm not sure that they get a positive indication of Torus pressure. And then the last item that was in the September letter, demonstrated capability for the time period, to the best of my knowledge, the containment Type A tests were run for 24 hours, and they're asking for credit for up to 56 hours. And also, as all of the committee members and consultants know, the containments haven't been Type A tested for 10 years, and many plants, including Vermont Yankee, have permission to extend that to 15 years.

So my summary, comparing or taking the Vermont Yankee's request and the September 20 letter, there are practical alternatives. I don't believe that there's a full positive indication of containment integrity because of the Torus, and I don't think containment integrity has been demonstrated for the c credited time period. But moving from the letter to Dr. Sheron's proposal, Dr. Sheron proposed a risk-based approach, Reg Guide 1.174, in lieu of implementing practical alternatives.

In the State of Vermont, we believe that this approach may have promise. However, through our review, Entergy's supplements, which haven't been reviewed by the staff officially yet, we are not sure that they accomplish the purpose and hopefully by my comments and the process that we're going through, we'll flesh out whether or not they do. Our first view is that they don't, and I'll explain why.

Entergy's risk evaluation --

MEMBER WALLIS: Excuse me. Did you get this inch thick PSA report that we have? Do you have that?

MR. SHERMAN: Yes.

MEMBER WALLIS: Is that what you're referring to here?

MR. SHERMAN: Yes. On October 21st they submitted Supplement 38.

MEMBER WALLIS: Revision Zero - okay.

MR. SHERMAN: And on October 26th, the larger report - both of them are here. The first submittal on October 21st was essentially an evaluation of the five elements of Reg Guide 1.174. I haven't got a slide which lists them. I know that subsequent presentations will have.

Then five days later they submitted the more full PSA. Actually, it's this. Included within that was a new top event, primary containment integrity. Their methodology was essentially to determine the core damage frequency difference between containment pressure available and not available. First, I'd like to --

MEMBER WALLIS: Maybe they should answer this. When you said does this mean difference between having the pumps work and having the pumps not work? What is the consequence of not having the pressure available?

MR. SHERMAN: The consequence of not having the pressure available if they took credit for containment pressure, containment over-pressure, the consequences of not having containment pressure available is that the pumps would not work.

MEMBER WALLIS: Would not work at all. It's not as if they partially work, as they probably would.

MR. SHERMAN: Well, I think we all believe that they would partially work. And I'm going to say something more about that, touch on that in just a minute.

MEMBER WALLIS: Yes, because some of these

PSA assumptions are not realistic; they're sort of yes/no-type answers.

MR. SHERMAN: I believe that, but I would bootstrap that to say the PSA methodology has some limitations on what you can make it do. First, I'm going to comment on two of the five Regulatory Guide 1.174 elements before talking about comments on the PSA. The first element that I want to mention is the proposed change is consistent with defense-in-depth philosophy.

I think the staff, maybe the licensee also, will talk a fair amount of why the proposal may be consistent with defense-in-depth philosophy, and I think that you, the committee, should look at that, see what they have to say. From the top view, the proposed change makes fuel cladding barrier dependent on the containment barrier which to us in Vermont is a significant modification of the defense-in-depth philosophy, but it's important that we listen to all of the comments in that area.

The other item is of lesser significance to us, the impact of the proposed change should be monitored. I've already mentioned this earlier in the presentation. Entergy claims credit for the 1.7 differential pressure. That's a valid monitor of the drywell, but I'm not convinced or sure that it's a valid monitor of the Torus, and in the penetrations to the Torus.

Now I'm going to go and mention seven comments that I have on the submittal that was provided on October 26th. I'm going to caveat those comments, again, we are not PSA experts, but we're trying to make the best of what we had in our review. Our first comment is that the model claims to consider only the time when the hard piped vent is used to prevent over-pressure. What this refers to is an implementation of a hardened vent, and the operator opening that vent to relieve containment pressure, and then not closing it and losing containment pressure.

In our view, if this statement were true, it's way too limiting. And I should mention that the licensee answered an RAI early in the review, stating that the only aspect it knew about containment over-pressure and the challenge was this hardened vent and its use. We think the problem is broader than that, that one has to look at the possibility of numbers of isolation failures, but the licensee mentioned that the model that was run didn't really just do that, it did more, so it may be a matter of what the words say in the supplement versus what the licensee really did.

But the words say that it's only the time when the hard pipe vent is used, and to us that's too limiting.

The next item in the fault tree for their new top event - they look at leakage paths both from the drywell and the Torus of two inches and greater. They only look at selective pathways, actually only those pathways which are purge and vent drain pathways. I am not convinced that they've included in their analysis all of the pathways that they might look at that might result in leakage. I think they make an assumption that if it's a closed system, there's no leakage. I think we'd accept that, unless there was an opening of that system through the LOCA or the accident itself. So again, we just had the question of whether they've included all of the leakage pathways in their evaluation.

Further to that item, Comment 3, it appeared to us that they included leakage pathways two inches and above, but they did not have a block or a split fraction or leakage pathways two inches and below, or below two inches, small bow piping. They did determine and they published in their supplements that a leak, a half-inch leak would defeat - I think it was .4 something - but approximately, a half-inch leak would defeat over-pressure, so it looks to us like there should be some consideration of small bore piping. Again, maybe through detailed review - it's not there, but it looks to us like there should be something there.

This one is technical and I almost feel like I have to talk to Dr. Apostolakis just directly on this. The case reported uses an initial small leak criteria, the base case, double the value of the leakage that would defeat over-pressure. It seems to us like it would have been more accurate to use the small leak criteria equal to the value for over-pressure. And there's a little bit counter-intuitive here. If you use a smaller leak criteria in your base case, then the core damage frequencies are higher because it is easier, it is more probable to have a smaller leak than a larger initial leak. So the fact that they used a larger initial leak as the initial condition creates a higher or lower - lower CDF, and I'll leave that comment there because it's down in the bushes, but with scrutiny I think it could be understood.

MEMBER WALLIS: Do they explain why they do this?

MR. SHERMAN: Well, they actually did a parametric study where they did a number of -- in the supplement they did a number of cases, and showed results for those cases; although, they didn't give Delta CDFs for those. And I'm not sure if the Delta CDF for the leakage case equivalent to the half an inch break doesn't bring you up around ten to the minus six, which is the cut-off criteria for 1.174, but I presume the licensee will say more about this this morning.

Comment 5 - the main steam isolation valve leakage pathway was not considered in their base case. I believe that's because they assumed it would be a closed pathway, although they have implemented within the last year or so something that is called alternate leakage treatment pathway, ALT. And in this pathway, they - within 30 minutes following an accident, a LOCA - they open a pathway from the downstream of the outboard MSIV. They open a pathway to the condenser, and this is for the alternate source term methodology that they use. And, therefore, the MSIV leakage has an effective open pathway, and ought to be considered, in my view.

And then number six, I believe that when they do that, they should take care to use their own MSIV leakage history. Their MSIV leakage history is not very good, but then I know that the industry's is not very good either, and I'm not sure who gets the benefit of my comment here.

MEMBER WALLIS: It's a half-inch hole or bigger?

MR. SHERMAN: No, their MSIV histories, the leakage that they found have not resulted in the leakage rate equivalent to a half-inch hole. But what this would lead to, Dr. Wallis, is a split fraction or a probability, the probability that the hole would be larger or smaller.

MEMBER SIEBER: They still meet Part 100?

MR. SHERMAN: Yes, there's no question about the dose criteria and the meeting of Part 100, and we don't question that.

MEMBER SIEBER: Okay.

MR. SHERMAN: My last comment, I imagine this is a bugaboo for all who are in the PSA area, and that is the fact that seismic in the PSA area is not done through probabilistic methods, but only through deterministic evaluations. And I'm not sure how the committee should look at the seismic interaction of this particular question, but here's the problem.

The problem is seismic can create the event, seismic can result in either a half-inch opening being created through the containment or small bore piping because of the particular seismic methodologies that the architect/engineer used for small bore piping. And this is something that one needs to think about if one is going to look at the containment over-pressure issue through probabilistic methods.

MEMBER SIEBER: As far as seismic analysis that this plant was built back in the time frame when templates were used to determine where supports were.

MR. SHERMAN: Yes.

MEMBER SIEBER: I take it there's been no subsequent re-analysis of the small bore piping, and the adequacy of supports?

MR. SHERMAN: I can't answer that. The licensee would be able to answer that, but I can answer that this plant has submitted an IPEEE evaluation and the IPEEE, basically they used Squib methods of doing walkdowns and looking at all the cases. So analysis, I'm not sure, Mr. Sieber, but in terms of review and consideration, I know they've done it, but in a deterministic manner.

MEMBER SIEBER: Okay.

DR. APOSTOLAKIS: You said that seismic analyses are not done probabilistically. They could be done. There are methodologies out there to do it, but they are a little bit expensive. My understanding is that in this plant they implemented a bounding analysis, which determines whether the equipment can survive a reference earthquake, which is not a probabilistic analysis, but that was accepted by the NRC. These methodologies have been approved, but your point that they perhaps should be doing a complete probabilistic analysis may be well taken. They may need to do that.

MR. SHERMAN: Actually, Dr. Apostolakis, my concern is more focused, and that is that I don't question the seismic adequacy of the plant. I only develop a question when the consideration of qualifying containment over-pressure through 1.174 techniques comes into play. Then I say well, the broad calculation doesn't really answer the question at hand. And what I conclude, and this is a possible conclusion, a possible conclusion is that PSA techniques are not an adequate method to resolve this issue.

DR. APOSTOLAKIS: That's why, as you well know, that the regulatory guide proposes an integrated decision making process, because they appreciate deficiencies. But this touches on an issue that I think is very important in power uprates, what we have seen so far. I mean, the rule is that you do this deterministically. Okay. And the licensee's usually submit a risk assessment as a supplement, and the requirements are not very stringent.

It seems to me that if you go to Regulatory Guide 1.174, the requirements now change, because now the PRA has to be fairly complete, has to be scrutinized, and it's a different ball game. And I'm not sure that this has happened. I remain to be convinced, but I'm not sure it has happened, so we don't just take the regulatory guide and just do an analysis, and then say okay, you can look at it when you do your deterministic analysis and have a better feel if things are going well.

Now it's a different thing, now it's risk-informed. Okay. And by the way, I mean, the analysis involving earthquakes, there is a very interesting document on the NRC website that refers to GSI 193, where there is a detailed event tree, several event trees starting with a seismic event, and they address the issue of large LOCA, and they refer to Mark 1 containments. And again, I didn't see any reference to that, and I think that's very enlightening to look at the event trees that the staff has developed there, and the timing of the pumps coming on line and so on, GSI 193.

MR. SHERMAN: Thank you. What I have just done is identified comments on the PSA that was submitted. And now I'd like to take ten slides and identify why I think that the licensee only provided part of the problem, and what I think the whole problem should look like.

The method that the licensee used was to show the CDF difference between containment over-pressure, with containment pressure available and containment pressure not available. But what I think that we would like to have seen or see is an evaluation that shows the CDF difference between NPSH failure of cooling pumps with no use of containment pressure over-pressure, and NPSH failure of cooling pumps with the use of containment over-pressure.

Now that's a different problem, which I'll try and explain. Let me get to one more slide.

DR. APOSTOLAKIS: Let me interrupt you for a second.

MR. SHERMAN: Yes.

DR. APOSTOLAKIS: I thought you were going to say that what you would like to see is a complete probabalistic evaluation within 1.174 for the EPU itself. This is really the issue. Right? And that would include what you want to see, and also what the licensee has done. In other words, here we have a situation where we're asking for a power uprate. The licensee does some risk assessment, but not within 1.174, and then they pick one element of that and they say we'll go to 1.174. And my question is why don't they go to 1.174 using the complete EPU? I mean, do the CDF before and after, including NPSH and everything. That would seem to me to be the way to do it.

MEMBER KRESS: And, George, I would add to that that since this is basically a late containment failure issue, that I would make that an additional constraint in 1.174, which it doesn't actually show up there.

DR. APOSTOLAKIS: You wouldn't just look at LERF, you would go beyond. Yes. But this is an interesting situation. In the past, we have talked about bundling of changes. This, I think, is the reverse. We have the big thing, and then we pick one element, and we do a complete 1.174 analysis. That's something that I think will be of interest to the committee. I'm sorry for interrupting, Mr. Sherman.

MR. SHERMAN: No, not at all. And I think of your comment very interesting. I, of course, would let both the staff and the licensee respond to that. We are more focused in our's, but the full would be the best.

DR. APOSTOLAKIS: Rest assured I will raise the questions when the staff is up there. But another thing that is very interesting since we're on the subject, if you look at the Delta CDF for the EPU that they submitted in the early application, and then the Delta CDF they calculated in the latest thing, it's higher. That's a very strange result, isn't it? I mean, the Delta CDF for the complete change is lower than the Delta CDF for looking at only a particular piece of it. And it's almost double, and I find that very strange.

MEMBER WALLIS: Well, it must be that the piece of it wasn't included in the original proposal.

DR. APOSTOLAKIS: I think that's the reason. And then the question is, of course, what else is not included. Please.

MR. SHERMAN: Thank you. The way that we looked at it, going back to the previous slide, instead of only the containment pressure available or not available, we think that for this particular problem it's the question of whether NPSH failure using containment over-pressure, and NPSH failure not using it would show at least what the probability that Dr. Sheron was speaking about.

The difference in the method is this; if we did what we are suggesting, you would capture the loss of the NPSH margin given up by crediting over-pressure. It is not only whether the over-pressure is there from containment integrity, but it is whether or not you needed that margin because of other uncertainties, which I'll identify on the next slide. So what we would propose is to assume in one case that the practical alternative was implemented, and that is, therefore, you had the full containment over-pressure margin, and then compare that with the case where over-pressure was credited on the step method that I showed on the earlier slide.

What we would see is not a new top event that is primary containment integrity, but a new top event that says pump fails due to inadequate NPSH.

MEMBER WALLIS: I have a philosophical problem with something here. I mean, crediting is something that is done by the agency. It's a regulatory thing. I thought PRAs, PSAs were supposed to be realistic descriptions of what happens. How can something sort of arbitrarily credited or not credited by an agency have an effect on reality?

DR. APOSTOLAKIS: The NRC can do that.

MEMBER WALLIS: No, but I have a philosophical problem with that.

MR. SHERMAN: We actually think, Dr. Wallis, that both can be accommodated, because in the probabalistic methodology, you can determine the probability of the event occurring in the first place, the probability of the temperature being so high as to require containment over-pressure.

As a matter of fact, we think that something along the line of a top event similar to the slide that I have up now would flush out the answer, and that is a pump fails due to inadequate NPSH, and then finding ways to assign the probabilities for the items in the boxes, which I'll mention a little bit further in, and finding ways to implement gates that only apply things when the over-pressure is needed. I think this might answer the question.

MEMBER KRESS: A comment on Dr. Wallis' philosophical problem. Given certain amount of credit for over-pressure, what one wants to ask in the PRA is, given that credit, what's the conditional probability that you won't have it. And that can be addressed in a PRA.

DR. APOSTOLAKIS: Yes. PRAs are always

done with certain boundary conditions, so you can view that as a boundary.

MEMBER WALLIS: Yes, but the action of an agency in crediting or not crediting something doesn't change physical reality.

DR. APOSTOLAKIS: No.

MR. HOLDEN: We're going to have to move forward quickly with the rest of this presentation.

MR. SHERMAN: And we'll get through as quickly as we can. What I'm going to mention now is items related to almost each of the boxes I have on here, but I'll be fairly quick. The first box is, there is some probability that the NPSHR required is not significant. The Staff SAR discusses at length that the licensee is using a reduced NPSHR, an NPSHR somewhere between NPSH head minus three, and head minus six, a situation that is in cavitation.

To the best of my knowledge, this reduced NPSHR is based on a Brown's Ferry pump test that included ten minutes of running in severe cavitation, 25 minutes in less severe cavitation. Also, on the pump acceptance tests, which were short duration tests, and on engineering judgment.

I note that Regulatory Guide 182, Section 2113, Rev 3, the current revision, states: "Pumps in cavitation should have performance tests at least as long as the pumps operate in cavitation." And in my view in this situation, we're talking about 56 hours or up to 56 hours. I think that it's unfortunate wording in Reg Guide 182, and along with the other changes that will eventually be proposed. Probably, this will need to get adjusted. Nevertheless, the issue is have the pumps been tested for the operation that is proposed? And my only point here is that there is some non-trivial probability the NPSHR used is not sufficient. I don't know whether it's one in a hundred, one in five hundred, one in a thousand, but there's some split fraction probability that could be placed in this event tree.

My next item is debris head loss. That's another item that we have in that event tree, and the item that I would identify, in particular, is the Vermont Yankee paint chip assumption. The licensee assumes that all unqualified paint fails, all unqualified failed paint is transported to the Torus, and no paint chips are deposited on the strainers. They base this on an Alden Lab test, which was a single test rig that's pretty different than this conflagration that's going to occur in the Torus if we had the whole situation.

I think if I were the engineer on the project, I would have assumed some low value of paint chip deposition, 10 percent or so, but they assumed zero. This, to me, is enough to tell me - I'm going to flip back on my slides - that the second box, number 3, debris head loss more than expected, there is some probability that it will be more than expected. And there needs to be some calculations done to understand what the probability that more than inspected eats into too much NPSH, and too much of the over-pressure margin.

I have little to say about this - containment fails to hold pressure. That's the one block that the licensee has done.

MEMBER WALLIS: I guess we have to ask the applicant - the no chips deposited on the Torus, is that because they don't get there on the strainer at all, because they go through the strainer because they're so small?

MR. SHERMAN: They assume that --

MEMBER WALLIS: I assume they never get there, but if they get there, they might go right through anyway.

MR. SHERMAN: I believe their testing was reasonable, in that their testing showed that the chips were heavy enough to fall to the bottom, and not get caught on the strainer, not get sucked into the strainer. But in the real accident situation in the Torus, there is some probabilistic distribution that that's not quite what's going to happen based on their one test.

The containment fails to hold pressure - that's the one item that the licensee did, and I've already identified our comments and questions on the way that they did that. Two other items, insufficient developed pressure, and some temperature higher than predicted - these values have already been calculated conservatively, so I would imagine these probabilities would be very low. However, there is some probability that even these conservative calculations are - if you're going to assign a probabalistic distribution, that they're not zero.

Finally, operator fails to retain sufficient pressure. Operators are trained to reduce containment pressure. The operators follow a fairly - not a complicated, but also not a trivial nomogram in their EOPs, and there is a probability that the operator will fail to retain sufficient over-pressure.

So finally, as conclusion, if we apply the letter that was written in September, it appears to us that over-pressure credit shouldn't be granted based on my earlier comments. If we apply Dr. Sheron's proposal, first, the 1.174 element of defense-in-depth concept and the modification of that concept is troublesome. Secondly, we believe Entergy analyzed part of the problem, but not the whole problem. If they analyzed the whole problem, it would shed light on what the risk of over-pressure credit was. And that's all I have for my proposal. Thank you very much.

MR. HOLDEN: Thank you very much. If anybody has any questions for Mr. Sherman.

MEMBER WALLIS: I think you were very helpful to us. Thank you.

MR. SHERMAN: Thank you, Dr. Wallis.

MEMBER BONACA: I have just one comment on the defense-in-depth, I believe the EPGs, at least for some BWR already include consideration of flooding the drywell under LOCA conditions to cool the core. I'm not sure what they are for Vermont Yankee, but the linkage may exist already to the EPGs. I just wanted to point out, that's something we certainly should explore.

MR. SHERMAN: Fine. And again, I believe that the staff will have significant additional comments about that.

MR. HOLDEN: Again, thank you very much.

MR. SHERMAN: Thank you.

MR. HOLDEN: Mr. Hobbs, are you ready?

MR. HOBBS: Yes. Good morning. I am Brian Hobbs, Entergy's Supervisor of Engineering Analyses for the Vermont Yankee Power Uprate project. I'd like to introduce Mr. Bruce Slifer on my right, who is the task owner and lead analyst for our containment and other fission products barrier analyses for the power uprate project. This morning I'll be providing an overview of the analyses associated with Entergy's request to credit containment accident pressure, also known as containment over-pressure included in the Vermont Yankee Power Uprate license amendment request.

Just a general statement about the State of Vermont presentation that you just heard. The State's items to consider in their presentation are almost all related to today's plant operation, so I will be discussing in my presentation the fact that issues such as strainer debris loading, containment integrity, containment leak rate testing are all issues for today, and regardless of whether we were requesting containment over-pressure to ensure adequacy of ECCS pumps net positive suction head, the items for consideration by the State would apply today, such as MSIV leakage - is it adequate? And I'll be answering that we meet the regulatory requirements, and we meet the conditions of our license relative to MSIV leak rate testing, so that's just a general comment.

The containment over-pressure credit is requested for application to the deterministic design basis analysis, loss of coolant accident, and ATWS events. And I'm going to be talking first about the deterministic design basis analysis today, and then about the probablistic safety assessment we performed relative to crediting over-pressure, so we're going to be switching back and forth between the real world and the risk world; although, if you consider the design basis accident the real world, it's the deterministic analysis.

MEMBER WALLIS: You're saying the risk world is unreal?

MR. HOBBS: I'm sorry?

MEMBER WALLIS: You said the real world and the risk world. Is there something unreal about the risk analysis?

MR. HOBBS: Well, I'm not a risk

specialist, and at times it appears to me to be an unreal world, but I'm sure it actually may be more realistic in some senses.

MEMBER WALLIS: Well, if it's not realistic, I don't want to hear about it.

MR. HOBBS: Okay. The topics I'll be presenting in this overview include background information on regulatory and industry precedence for crediting over-pressure, Entergy's basis for requesting over-pressure credit for the deterministic analysis, specifics of the over-pressure credit requested, and then details of the evaluation performed to assess the risk of crediting containment over-pressure. And the staff is going to be following this presentation, so I'm not going to get into a whole lot of detail relative to the deterministic analysis, just give you some background information.

Containment over-pressure credit has been granted by the NRC for 25 nuclear plants to meet long-term containment cooling requirements. This includes four boiling water reactor plants granted over-pressure credit in conjunction with an extended power uprate, and those are Duane Arnold, Brunswick I and II, Dresden II and III, and Quad-Cities I and II.

Regulatory Guide 1.82 titled "Water

Sources for Long-Term Recirculation Cooling Following a Loss of Coolant Accident", defines the basis for crediting over-pressure.

MEMBER WALLIS: Again, this is not yet a regulatory guide, this is a draft.

MR. HOBBS: Regulatory Guide 1.82 Rev 3.

MEMBER WALLIS: Is that the real one or is that the new draft?

MR. HOBBS: Rev 3 is the real one.

MEMBER WALLIS: Okay. I'm sorry. Then I know what you're talking about. Thank you.

MR. HOBBS: Vermont Yankee conforms to the aspects of Regulatory Guide 1.82 Rev 3 that pertain to crediting over-pressure. This table lists the boiling water reactors with Mark 1 containments similar to the Vermont Yankee design that currently credit over-pressure in their licensing basis. The extended power uprate plants on this list include Duane Arnold, Dresden and Quad-Cities, not listed here is the Brunswick plant, although it does have a Mark 1 containment, and it did request credit for over-pressure as part of its extend power uprate license amendment request, and did receive that credit.

During the design basis loss of coolant accident, the Vermont Yankee's low pressure ECCS pumps, which are the residual heat removal and core spray pumps take suction from the suppression pool and supply water to the reactor in order to maintain fuel temperature less than the maximum allowable. Suppression pool temperature and pressure increase as a result of the postulated large reactor coolant piping break.

The Vermont Yankee primary containment is designed to automatically isolate in order to prevent the release of radioactive material. Isolation of the containment also bottles up the energy released from the hypothesized reactor piping break. It is this accident pressure that we are requesting credit for. And accident pressure is not a new condition resulting from power uprate, it's available in the current postulated Vermont Yankee design basis accident analysis. Power uprates does increase decay heat which results in a design basis analysis peak suppression pool temperature that's approximately 12 degrees greater than the current licensed thermal power peak, which reaches full power uprate at peak of 195 degrees Fahrenheit.

MEMBER WALLIS: Is this a very conservative-type analysis, or is this a realistic one? What's the real temperature likely to be?

MR. HOBBS: I'll be showing a slide momentarily here that contains best estimate results.

MEMBER WALLIS: So this contains significant conservatism?

MR. HOBBS: This contains the maximum allowable values for the --

MEMBER WALLIS: Because the heat has to go somewhere, presumably conservatism assumes that it's not taken out by some mechanisms which actually occur or something?

MR. HOBBS: Correct. At the temperature reached by the power uprate as far as suppression pool temperature goes, the available net positive suction head is less than required; hence, the need to credit containment over-pressure.

MR. LEITCH: You do not have a problem with requiring containment over-pressure for the current power level. Is that correct?

MR. HOBBS: We do not credit containment over-pressure for the current licensed thermal power.

MR. LEITCH: And this increase in suppression pool temperature of 12 degrees is what generates the issue of inadequate NPSH. That's the only impact is the 12 degrees?

MR. HOBBS: Yes.

MR. LEITCH: So the 12 degrees maximum suppression pool temperature is enough to tip the scales from not needing containment over-pressure to needing containment over-pressure.

MR. HOBBS: That's correct.

MR. LEITCH: Okay. Thank you.

MR. HOBBS: The licensing basis change request crediting a portion of the over-pressure that is available in the suppression pool to ensure adequate pump net positive suction head. This slide you saw just a few moments ago, and it contains the requested over-pressure credit versus time for the Vermont Yankee large break LOCA.

MEMBER WALLIS: Now this 1.5 percent weight containment leakage, is that a rate per day or something?

MR. HOBBS: Weight percent per day, yes.

MEMBER WALLIS: It doesn't say. It says per day, doesn't mean anything to me, so that's per day.

MR. HOBBS: Per day.

MEMBER WALLIS: And what is that based on?

MR. HOBBS: The allowable containment leakage rate in our license is 0.8 weight percent per day. That is for the primary containment. That does not include MSIV leakage. This value of 1.5 percent weight percent per day incorporates both the integrated containment leak rate test allowable limit, and the maximum MSIV leakage rate limit.

MEMBER WALLIS: So it might then be important for you to monitor this leakage rate more than you have in the past in order to assure that these calculations are correct?

MR. HOBBS: These leakage rates that are in our license today apply to containment integrity for today, so for radiological release purposes, we need to meet the --

MEMBER WALLIS: No, I'm trying to get at the question of allowable on license and what's real. You have to actually measure these things on some sort of a regular basis to satisfy yourself that the MSIV leakage is what you predict.

MR. HOBBS: Yes, and we measure those --

MEMBER WALLIS: And if you're more dependent on it, you might have to measure it more often.

MR. HOBBS: Agreed, yes. And there is an additional dependency that I'll be talking about here that we're creating, but there is a dependency today, also, relative to allowable leakage limits.

MEMBER KRESS: You measure it how often now?

MR. HOBBS: We measure integrated leak rate testing every ten years, although we do have an exemption that's been approved to extend the current leak rate test to an additional five years. MSIVs are leak rate tested every cycle.

CHAIRMAN DENNING: Tell me with regards to this inerting question and its additional ability to give you information on what the leakage is from the containment - what can you really infer with regards to drywell leakage, and can you infer anything with regard to Torus leaking?

MR. HOBBS: And, Dr. Denning, I'll be talking about one of the elements of Reg Guide 1.174, which is monitoring of the proposed licensing basis change shortly here, but there is a strategy for monitoring leakage from the drywell, and I'll also be talking about how we propose to ensure that we don't exceed the integrated containment leak rate allowable limit for the Torus, as well. So I'll be getting to that shortly.

Now the lowest line on this curve here is the core spray required over-pressure for this event at EPU conditions. The next lowest line is the residual heat removal pump over-pressure required. The highest line is the available over-pressure assuming the 1.5 weight percent per day containment leakage, and also assuming that containment sprays are being operated continuously during this event, so those are the most conservative assumptions relative to available over-pressure.

So the middle line here is the credited over-pressure that's being requested, and that's a step curve that shows how much over-pressure credit we need. The peak is 6.1 PSIG, and the duration is 56 hours.

MEMBER WALLIS: Well, it would seem to me that any curve between the diamonds and the triangles would suffice.

MR. HOBBS: That is true.

MEMBER WALLIS: Why do you have this particular one?

MR. HOBBS: Well, the reason we have it midway between is to establish and maintain sufficient margin.

MEMBER WALLIS: Well, how do you know what's sufficient margin without some probabalistic or some other kind of analysis? Is this just a word you throw out, or does it mean something, "sufficient margin"? Is there some requirement in the law that says it has to be 1 psi or something?

MR. HOBBS: There is no quantitative basis.

MEMBER WALLIS: So it's just some sort of engineering guess that you have enough margin if you make it 1 psi more than you need?

MR. HOBBS: Well, we didn't want to be on the ragged edge of margin for the deterministic analysis, so that's why we --

MEMBER WALLIS: You might as well have asked for the upper curve.

MR. HOBBS: Yes, but then we didn't want to go and attempt to recapture all the over-pressure available, so this is how much we need.

MEMBER WALLIS: You need the diamonds. You don't need anything above that really.

MR. HOBBS: Right.

MEMBER WALLIS: Presumably, since I understand NPSH margin of zero is acceptable to the agency, seemed to me in part of the SER, they were allowing zero margin.

CHAIRMAN DENNING: And if we can understand a little better the upper curve, the sprays are operating. That means that the drywell, that at least where the sprays are operating - where are the sprays operating?

MR. HOBBS: The sprays are operating in both the drywell and the suppression pool.

CHAIRMAN DENNING: And that means that the partial pressure of the vapor is whatever the pool temperature is, the saturation value for whatever the pool temperature is. Is that basically what the partial pressure of the steam is or vapor?

MR. HOBBS: Let me turn to Bruce Slifer over here to the microphone.

MR. SLIFER: Well, the calculation of the pressure inside the containment would consider the actual conditions in the airspace, so when the sprays are operating, the temperature would actually be closer to the spray temperature rather than the suppression pool temperature. So the --

CHAIRMAN DENNING: I'm sorry. The sprays are not pulling from the suppression pool.

MR. SLIFER: They're pulling from the suppression pool, but they're going through the heat exchanger and being cooled off.

CHAIRMAN DENNING: Okay. So it's whatever -- so you have to take into account that heat exchange.

MR. SLIFER: That's correct.

CHAIRMAN DENNING: I'm sorry. Okay. It's not as simple as I thought. Continue.

MR. HOBBS: The over-pressure credit request is based on the Vermont Yankee pump curves, which are formulated from specific performance tests for Vermont Yankee ECCS pumps. This is the same basis being used for current licensed thermal power. We are aware of the Brown's Ferry pump tests at reduced net positive suction head, but do not credit margin from these tests in our analyses.

MEMBER WALLIS: So these specific tests that you had, they ran with reduced NPSH for 56 hours?

MR. HOBBS: The specific tests for our ECCS pumps ran for a duration less than 56 hours, but they were the original pump tests performed --

MEMBER WALLIS: How much less? Four hours or something like that my colleague said. Is the test report four hours, so four hours seems somewhat less than 56.

MR. HOBBS: The original tests were done by the pump vendor, and they were done just to demonstrate that -- determine what the minimum NPSH required was. Done in accordance with standard test procedures for pumps in that era. These tests were performed in 1969 and 1970. The purpose of these tests was to establish the minimum required value. It wasn't for the purpose of establishing a duration of a time allowable to operate at those conditions.

MEMBER WALLIS: It says, "up to four hours", I think, here. Expected modes of operation - that doesn't say that's how they were tested. It says "expected hours of operation for less than four hours."

MEMBER SIEBER: Well, at the time that Vermont Yankee was built, it didn't need over-pressure credit, so you would test the pumps in those modes for a long enough period of time to demonstrate that they would work. When you come to a new situation where you take credit for over-pressure protection, you're basically still operating in the same regime. The temperature is hotter, which reduces NPSH. On the other hand, you have an over-pressure which compensates for that, so question as to whether that's adequate or not, or has any relationship to the amount of time that the credit is needed doesn't appear to be relevant, at least in my reading of the test report.

MR. HOBBS: We actually went back to the pump vendor in 1997 or 1998, and asked them to determine what the acceptable durations of operation were at those minimum values. They performed an evaluation for us at that time, and at the minimum values that were tested, they said we could operate up to seven hours at those conditions. And then they said after that period of time, they provided a ramp up to some upper level, which was approximately four feet higher in NPSH, which would be acceptable for a long-term operation up to 8,000 hours, when they did an evaluation based on an evaluation of impeller lifetime characteristics.

MEMBER WALLIS: It's the impeller lifetime that matters, it's not the bearings or anything like that, or the seals? That thing is shaking considerably.

MEMBER SIEBER: It's the bubbles --

MEMBER WALLIS: It's only the impeller that matters.

MEMBER SIEBER: It's the bubbles collapsing on the impeller that --

MR. HOBBS: Right. It would be the effect of the cavitation --

MEMBER WALLIS: So the shaking of the pump has no effect at all.

MEMBER SIEBER: Well, it does, but it's a secondary effect.

MEMBER RANSOM: Those required values were a 3 percent drop in head due to cavitation?

MR. HOBBS: Actually, the minimum value for the HRH pump is closer to 6 percent head drop. At the time these pumps were tested, they were not living to a standard which was based on a head drop. These tests were done according to the manner that meets the requirements of the customer. The customer at that time was General Electric. They were the purchasers of those pumps. They specified the conditions that they would --

MEMBER RANSOM: But the long times of operation you just quoted were 6 percent drop in head then.

MR. HOBBS: Yes, they were.

MR. LEITCH: I have a question about the curve that's on the screen right now. You expect, I take it, the operator to more or less follow this stepped curve. And I guess the claim that's made is that there's no change required to your emergency operating procedures, but it seems to me that there would be a change if we expect the operator to follow this new requirement to follow that step curve.

MEMBER SIEBER: Well, the operator doesn't follow the step curve. He has to be above the minimum

NPSH line there, which puts an additional burden on the operator.

MR. WAMSER: If I can address the question.

MR. HOBBS: Yes, I'd like to have Chris Wamser, our Operations Superintendent, address that.

MR. WAMSER: Good morning again. Chris Wamser, Operations Manager. The guidance for maintaining net positive suction head for both the residual heat removal pumps and the core spray pumps is already in place, and has been in place in our emergency operating procedures. This step or staircase look on this graph that we have up on the slide is a simplified guide that is provided in the EOPs. It is previously existing because the EOPs are essentially written for design basis and beyond design basis-type accidents, so that guidance exists already. And we have trained on this, and we will continue to train on this, so this is not new information for operators. This is not a new change to the EOPs. There is no change to the EOPs as a result of this.

MR. LEITCH: Well, the general EOP practices are unchanged, but are the numerical values changed in line with this curve?

MR. WAMSER: Not for this, no. The

existing curves encompass this.

MR. LEITCH: Okay.

MEMBER WALLIS: The curve is the same, but he has to at certain times now maintain 6 psi, whereas before he may only have had to -- didn't have to maintain anything. Something has changed about what he has--

MR. WAMSER: The existing guidance looks at the parameters of pump flow, Torus damage here, et cetera.

MEMBER WALLIS: Right. So it's the same guidance, but what he tells you is changed.

MR. WAMSER: Well, prior to taking action to depressurize or lower containment pressure, the operators are responsible for determining what the net positive suction head is required for the pumps under the conditions that exist at that time.

MEMBER WALLIS: How does he know how much junk is on the screen when he's determining this NPSH?

MR. WAMSER: He does not -- that is not a variable that he is asked to --

MEMBER WALLIS: So how does he know what NPSH he needs? Does he have some other measurement that --

MEMBER SIEBER: He can tell if the pump is cavitated.

MEMBER WALLIS: He can tell the pump is cavitated.

MR. WAMSER: We do have indications, we have a separate procedure for ECCS pump cavitation, but within the EOPs, the existing curves for containment pressure and system flow exist and are conservative to ensure that an individual would not reduce containment pressure below that which is required for --

MEMBER WALLIS: This is assuming a conservative screen blockage then, presumably.

CHAIRMAN DENNING: Let me understand something here about what the operator actually does. He would never do anything intentionally here to reduce the pressure below what we see as the blue curve, would he? There's no -- I realize that there is some requirement for reduction below some level, but I think we're assuming here that that blue curve is really taking into account any actions he might take. He's never going to take an action -- I mean, he's never going to intentionally take an action that would ever reduce the pressure below the blue curve, would he?

MR. WAMSER: If the blue curve is the

upper curve, that's true.

CHAIRMAN DENNING: Yeah, the blue curve. Well, I meant the upper curve. So he's not taking actions --

MEMBER SIEBER: To follow the steps.

CHAIRMAN DENNING: -- to follow the steps, or in any way reduce some of the assumptions that underlie here, which is that the non-condensible gases are not escaping this containment faster than the 1.5 weight percent by some intentional action. Okay?

MEMBER SIEBER: Let me ask a question while you're up there.

CHAIRMAN DENNING: He's doing very little. He does reduce the pressure, if necessary, because of other reasons, but he's not -- there's very little he can do in this case in reality.

DR. APOSTOLAKIS: Then what is the change in the EOP that this gentleman --

CHAIRMAN DENNING: There is not one. Actually, they're saying there is no change.

MR. WAMSER: That was my point. This is not -- there is no change to the EOPs as a result of this. There's no additional or new training that needs to be provided to operators as a result of this. The guidance has existed, and I just want to make sure that was clearly addressed, that the operator's implementation of the Emergency Operating Procedures is not changing as a result of this.

CHAIRMAN DENNING: You know, we're going to have to move more quickly than we normally do.

MEMBER WALLIS: I think we need to challenge this. I mean, if some of the things that Bill Sherman talked about, like breaks in pipes actually are occurring and your leakage is bigger than predicted here, the operator may well have to do something. You may get below that top blue curve in the event of a pipe break that bends the containment more than predicted.

MR. HOBBS: And I'll be talking here momentarily --

MEMBER WALLIS: You will talk about that?

MR. HOBBS: -- Dr. Wallis, about if we assume the single failure in the deterministic analysis was containment, we would not need containment over-pressure.

MEMBER WALLIS: So you don't need it anyway, so after it's all done --

MR. HOBBS: If the single failure is containment, we don't need containment over-pressure. Okay. Moving along here, at the NRC's request, Entergy developed a risk-informed evaluation of crediting over-pressure in accordance with Reg Guide 1.174, which is an approach for using probabalistic risk assessment and risk-informed decisions on plant-specific changes to licensing basis. The reg guide specifies areas or elements for consideration when assessing risk, which is shown here. I'll be discussing how these elements were considered in the next few slides.

Relative to the first element, Vermont Yankee continues to meet current regulations which are the design basis analysis requirements when crediting over-pressure to ensure adequate ECCS pump net positive suction head. The proposed crediting of over-pressure is consistent with and does not significantly degrade the defense-in-depth philosophy, as specified in the second reg guide element. The same methods will be applied at power uprates as are used at current licensed thermal power for prevention and mitigation of accidents.

MEMBER WALLIS: Are you going to address the question of independence of areas?

MR. HOBBS: Yes. The defense-in-depth safety philosophy avoids over-reliance on any one component or system. This ensures that we take into account the inherent uncertainty associated with equipment and human performance. Vermont Yankee relies on multiple means to accomplish safety functions, and prevent the release of radioactive materials, none of which are affected by over-pressure.

MEMBER SIEBER: Let me just get this clear. If you end up with assess the containment leakage, what you're saying is that will not cause the clad to fail. And what does --

MR. HOBBS: Well, in the deterministic analysis, if we were to assume an additional single failure of containment, then we would have core damage. In other words, if we lost containment integrity which caused us to lose net positive suction head adequacy for ECCS pumps, we would have core damage. But that would be two single failures, because we would not only fail on our heat exchanger, we'd be failing containment, as well, so that's deterministic.

Now in the PRA world, we looked at this, and we looked at what the effect was on core damage frequency and large area release frequency as a result of crediting over-pressure, and we determined that was very small. So I guess in the deterministic world, we have to pick our single failures and decide which one is most conservative.

MEMBER SIEBER: On the other hand, it's possible, not likely but possible, for you to have a containment failure which you don't detect, enough leakage that you can't really pick it up in the normal day-to-day operation.

MR. HOBBS: A passive containment failure that occurs between testing of the containment leakage.

MEMBER SIEBER: You've got a 15-year span that you're talking about.

MR. HOBBS: Right. And we'll be talking about the fact that we test our containment penetrations individually. We test more than 50 percent of those every cycle, so rather than the integrated leak rate test, we test the individual containment penetrations on a regular basis. So we have high confidence in containment integrity.

The regulations require incorporation of the worst case single failure for the design basis analysis, which for Vermont Yankee is failure of an HRH heat exchanger. If the single failure was assumed to be loss of containment integrity, rather than the HRH heat exchanger, there would be no need for overpressure credit, because we would have adequate suppression pool cooling, keeping the temperature well below that where we would have adequate net positive suction head.

MEMBER WALLIS: So why do you need to apply for it. It would seem to me just appeal to the single failure criterion and you're home free. Why do you need to apply for this over-pressure credit?

MR. HOBBS: Because the single failure we currently apply, which is the loss of the HRH heat exchanger, is the most limiting relative to the design basis accident for peak cladding temperature.

MEMBER WALLIS: Yes. But then you're saying that additionally you have to apply for containment credit, so that the containment credit is somehow on top of the single failure?

MR. HOBBS: Yes.

MEMBER WALLIS: So it's a bit -- it depends on how you read the regulations, perhaps? No, the staff is quite clear.

MR. HOBBS: Okay.

MEMBER WALLIS: Well, go ahead.

MR. HOBBS: The staff will be, I'm sure, able to address that.

DR. BANERJEE: Let me just ask a question.

If you had a containment single failure, that water gets cool enough that you don't get this 12 degree rise?

MR. HOBBS: Yes. And I have a table that will show you here momentarily what the temperature peak is for that case.

DR. BANERJEE: But it depends on the size of the failure, right or not?

MR. HOBBS: The size of containment failure?

DR. BANERJEE: Yes.

MR. HOBBS: It can be an infinite size.

DR. BANERJEE: It can be very small. Then what happens in that case?

MR. HOBBS: That is true. We also did a sensitivity that showed you would need 27 times the allowable leakage rate to lose containment over-pressure for the deterministic analysis. And that would be a hole size that would be detectible, if it were in the drywell.

DR. BANERJEE: Now we heard some discussion that a half-inch hole would actually give you --

MR. HOBBS: That equates to the 27 times the allowable leakage rate.

DR. BANERJEE: Now if you've got a half-inch hole, how much would your water cool? Would it cool at all?

MR. HOBBS: It would be the same temperature.

DR. BANERJEE: The same temperature, right?

MR. HOBBS: Right.

DR. BANERJEE: So if you got a single failure which was a half-inch hole, you would lose over-pressure, and the water wouldn't cool?

MR. HOBBS: Well, if the half-inch hole were the single failure, in the deterministic analysis we said we have both RHR heat exchangers available, which means we have one single failure, not two.

DR. BANERJEE: Right.

MR. HOBBS: Then we would cool the pool sufficiently so that we didn't require over-pressure, if that half-inch hole were our single failure.

DR. BANERJEE: So you only need that over-pressure if one of the RHR heat exchangers is not working.

MR. HOBBS: Yes.

DR. BANERJEE: Okay.

MR. HOBBS: Okay. And back to the question of independence relative to defense-in-depth. We do acknowledge the fact that the dependence on the core integrity becomes reliant on containment integrity here, but that's the case today. We have dependence today between the containment and functioning of the emergency core cooling system, and I can specify two examples of that. One is the fact that the primary containment holds the water that serves to recirculate for core cooling during an accident. If we lost primary containment and lost the source of water for recirculation, then we would have no emergency core cooling success. So we have a dependency today between containment integrity and ECCS functionality. Another example is environment qualification. If we lost containment integrity today which resulted in exceeding the EQ qualification of some of the equipment that makes the ECCS system work, some of the logic equipment, et cetera, then we could have a failure of the ECCS system, as well. So we're crediting a new dependency, which is for the over-pressure credit between containment integrity and ECCS functionality, but we have some dependencies today.

MEMBER SIEBER: The ones you cite are pretty gross compared to the refined, relatively small loss of containment integrity that would result in the situation we're discussing.

MR. HOBBS: Right.

MEMBER SIEBER: It takes a pretty big insult to override the EQ qualifications.

MR. HOBBS: Okay. These are some of the conservative design basis assumptions that we talk about here, and we have some cases for sensitivities on these, but essentially, we assume all these worst case conditions in our design basis accident.

Realistically, as we've mentioned here, containment over-pressure would not be required except for the fact that the regulations require assumption of all worst case inputs.

MEMBER WALLIS: Now you make this assertion, is there some analysis we can see that we can examine, to see how you've reached this conclusion? Are you going to tell us that?

MR. HOBBS: Yes, I'm going to tell you right now.

MEMBER WALLIS: We can't look at analysis now, but you're going to give us enough material, we can verify that your realistic analysis is okay?

MR. HOBBS: Yes.

MEMBER WALLIS: And we get it pretty soon, so we can actually look at it before we have to make any decision?

MR. HOBBS: We can do that. Okay. This table shows that over-pressure credit is only needed for the worst case design basis assumptions, which are presented in case one. This reflects the maximum conservatism in this design basis event. If the required single failure was the primary containment, then case two would be the result. And this shows there would be no need for over-pressure credit since both our HRH heat exchangers would be available, and peak pool temperature would be substantially lower. For cases three, four, and five, where surface water temperature or initial suppression pool temperature, or other input assumptions are not assumed to be at their maximum allowable value, suppression pool temperature does not increase to the point where over-pressure is required to ensure adequate net positive suction head. Therefore, a more realistic analysis would not result in the need to request over-pressure credit.

MEMBER WALLIS: You use this word "nominal" again. What does that mean? Does it mean what is most likely or something, or what?

MR. HOBBS: Let me ask Bruce Slifer to

chime in on that.

MR. SLIFER: When we say "nominal", what we're talking about are things like 100 percent reactor power, instead of 102 percent power --

MEMBER WALLIS: More realistic is the word you should use. Nominal I have trouble with, because that can mean something defined in a regulation or something, sort of a people-defined thing rather than a real thing. You mean a realistic, is that what you mean?

MR. SLIFER: Okay.

CHAIRMAN DENNING: So this initial pool temperature in the first case, for example, is that something that is experienced in normal operation, in the variability you see, what is the maximum pool temperature that you really see?

MR. SLIFER: As I say, in response to an accident?

CHAIRMAN DENNING: No, this - I assume this is initial pool temperature.

MR. SLIFER: Oh, correct. Well, the variation tends to be somewhat seasonal. In the wintertime the temperatures are lower, in the summertime higher. I don't think we've ever gotten to 90 degrees during normal operation. There could be times when you test the HPCI and RCI systems where it goes up, and the tech spec allows it to go about 90 degrees occasionally, but then you have a certain period of time to get it back down below the limit.

CHAIRMAN DENNING: But it could be that it just went through some --

MR. SLIFER: We've estimated looking at plant records that the probability of it being at that level would be less than one day out of the year or something like that.

CHAIRMAN DENNING: I don't know if there's a common cause relationship between these if you went into LOCA and whatever transient you went through to give you a higher core temperature.

MR. SLIFER: Well, just taking a look at the data we have available to us.

CHAIRMAN DENNING: Okay. I was just trying to get a feeling for that.

MEMBER WALLIS: But normally, it's around 70 degrees or something like that?

MR. SLIFER: It basically is room temperature, whatever the actual temperature is, that tends to be the temperature of the Torus. The surface water temperature, which is a more important factor, is, of course, dependent on the river temperature.

And in Vermont, the river temperature is around 32 degrees --

MEMBER WALLIS: If it gets to 90 degrees, I'd be very surprised.

DR. APOSTOLAKIS: Why is this slide titled "Risk Assessment"? I never understand -- what is the risk here?

MR. HOBBS: The risk assessment is coming up, Dr. Apostolakis. And this is element two of the Reg Guide 1.174, which talks about defense-in-depth. So I guess this is a risk-informed approach to deterministic analysis.

DR. APOSTOLAKIS: So the message of this slide is that defense-in-depth is not compromised. Is that what it is?

MR. HOBBS: It is not compromised. Right. It's maintained.

DR. APOSTOLAKIS: Because? Maybe you've said it, but because what? Because case one is the only case where we need containment over-pressure? And then what?

MR. HOBBS: I'll be talking here shortly about our exact defense-in-depth --

DR. APOSTOLAKIS: Okay.

CHAIRMAN DENNING: And the point at which you go between needing no credit to some credit is someplace in-between 185 and 195. Can you tell us what that number is?

MR. HOBBS: It's actually 185.

CHAIRMAN DENNING: 185 is the threshold. Continue.

MR. HOBBS: Okay.

MEMBER SIEBER: And that's where you'd be without EPU.

MR. HOBBS: Okay. Crediting over-pressure applies in existing condition in containment, and does not result in additional challenges or new types of challenges that would increase the probability of a fission product barrier failure. No new accident initiators will result from crediting containment over-pressure.

There are also no changes to the plant or changes in plant procedures in order to credit containment over-pressure; and, therefore, no increase in the failure probability as a result of those types of changes. Although adequate net positive suction head has been analyzed as being dependent on containment integrity, the probability of the worst case design basis event conditions occurring simultaneous with a lose of containment integrity is very small. Okay.

Crediting containment over-pressure does not degrade the current Vermont Yankee operator philosophy and practice of ensuring adequate pump net positive suction head, as Mr. Wamser discussed. Operator actions continue to mitigate fission product barrier challenges through training and following procedures.

Relative to the AST implementation, the ALT path, which was mentioned earlier this morning, is a pathway that's already open, and the operators confirm that on a loss of power or loss of air, that that path remains open. That does not affect MSIV leakage. It's basically a pathway to ensure you have adequate play down of elemental iodines and other fission products in accordance with the alternative source term regulation, so this does not increase any leakage from containment.

The over-pressure credit request preserves adequate margin for the deterministic analysis, which is the third element of Reg Guide 1.174. The currently --

MEMBER WALLIS: We had a discussion yesterday about what you mean by "adequate margin".

MR. HOBBS: Right.

MEMBER WALLIS: Does this mean simply meeting the regulations or meeting the regulations with some bit to spare, what you call margin.

MR. HOBBS: That second statement is --

MEMBER WALLIS: It's the bit to spare you're talking about.

MR. HOBBS: Bit to spare, right.

MEMBER WALLIS: But your margins have gone down.

MR. HOBBS: As a result of --

MEMBER WALLIS: How did you decide that it's not adequate?

MR. HOBBS: Well, based on engineering judgment, and benchmarking, and --

MEMBER WALLIS: Your engineering judgment might be different from mine.

MR. HOBBS: Might be different, right. And ultimately, we rely on the regulators to tell us --

MEMBER WALLIS: Are you going to tell us more about this in two weeks time, what you mean by margin and why it's okay?

MR. HOBBS: Yes.

MEMBER WALLIS: Okay. You don't need to go into it now.

MR. HOBBS: Okay. And as previously described, the deterministic analysis contains substantial margin, as well. Okay. Moving on to the risk assessment.

Entergy performed a risk assessment to determine the impact on core damage frequency in large early release frequency as a result of crediting over-pressure EPU conditions. This risk assessment was based on more realistic input assumptions compared to the design basis accident analysis. The impact of other EPU design changes were previously addressed in a separate risk assessment documented in the license amendment request. This assessment for over-pressure estimated the risk of establishing a dependency between over-pressure, which is a function of containment integrity, and success of low pressure ECCS pumps for cooling the core. And the results show a very small change in core damage frequency of 5.78 E to the minus 7, and large early release frequency of 4.5 E to the minus 8 as a result of crediting over-pressure.

MEMBER WALLIS: Now you say it's very small because it's less than E minus six.

MR. HOBBS: That's correct.

MEMBER WALLIS: So if it were twice as

big, it would actually be above E minus six. So you must have a pretty good PRA with that accuracy.

MR. HOBBS: Yes.

DR. APOSTOLAKIS: The issue that came up earlier in your October 26th submission, where you look only at containment over-pressure, you get this number of 5.8 or you report 5.78 here, ten to the minus seven. However, in the SER that I read, the staff quotes 310 to the minus seven per reactor year as part of your earlier submission that looked at the whole EPU. So if I do a risk assessment on the whole, I get a number that's lower than if I do a risk assessment on a piece of it, which is kind of confusing to me. I mean, this analysis of containment over-pressure is one part of the risk assessment for the EPU itself, so that it's one contributor, so how can one contributor be higher than the --

MEMBER WALLIS: I think it's because it's an artificial contributor, assuming something which isn't realistic. This goes back to the --

DR. APOSTOLAKIS: No, this is supposed to be a realistic analysis.

CHAIRMAN DENNING: But, of course, there could be pluses and minuses, George.

DR. APOSTOLAKIS: Huh?

CHAIRMAN DENNING: It can be pluses and minuses.

DR. APOSTOLAKIS: Is that a reason? This is much more detailed --

CHAIRMAN DENNING: I don't know if that's the reason, but it could be a reason.

MR. PALIONIS: I'd like to address that, if I could.

CHAIRMAN DENNING: Okay.

MR. PALIONIS: Yes. Mark Palionis, PSA Engineer for Vermont Yankee. You're quite correct, the original EPU submittal has a risk assessment associated with it. And as you've already discussed, realistically we did not expect, we don't expect to have to depend upon containment over-pressure. So for our thermal hydraulic analysis in support of our PRA, where we used realistic assumptions, we never need containment over-pressure. We don't need to credit containment over-pressure, so for this submittal we were requested to assess the risk associated with the assumption, artificial assumption that containment over-pressure is required. As far as we're concerned, it's artificial, because you have to max out all of your parameters if they're max possible, in order to get to a condition where you would require that containment over-pressure. So what we did was look at Delta CDF between what would be required, what the CDF would be if containment over-pressure is required for the low pressure ECCS success, versus the CDF where containment over-pressure is not required to support low pressure ECCS success.

MEMBER WALLIS: That's a funny kind of risk analysis.

CHAIRMAN DENNING: It's a variation in success criteria.

MR. PALIONIS: I would characterize it more a sensitivity study than --

DR. APOSTOLAKIS: So your number is the earlier one of 310 to the minus seven. That is a more realistic number.

MR. PALIONIS: That's a more realistic number, yes. Yes, indeed.

CHAIRMAN DENNING: Thank you. Continue.

DR. APOSTOLAKIS: Well, again, I looked at -- I mean, it appears that the timing here is important. I mean, in your PRA you sort of dismiss the seismic issue. You say we did a bounding analysis using an accepted method, and the numbers came out okay with respect to the reference earthquake of .3g I think. Now I don't know how relevant this is, but if I look at the GSI 193, there is a detailed analysis of a large LOCA with time in there of when the pumps come into the picture. And in the case of what they call a fast LOCA, they find some sequence there that can cause common cause failure so the pumps and so on - although, its frequency is still low. It's on the order of a few ten to the minus six.

I didn't see any of that in your PRA. Is it because you don't have a seismic probablistic risk assessment, so you are not able to do it? Is it because you dismiss it, and the analysis that is on the website of the NRC under GSI 193 is irrelevant to you? There should be some sort of discussion, because that analysis refers specifically to Mark 1 containments. Maybe the probability is still low. I am not saying that this would upset really what you have done, but I found it a little odd that the regulator has a whole analysis there that starts with a seismic event, loss of off-site power as a result of the seismic event, the diesels come on, then they give you details, they give a curve of the probability of failure of the pumps as a function of time, and all LPCI pumps fail because they come into the picture six seconds into the accident. Then there is a conditional probability of losing all containment spray pumps, which is .24. So, I mean, we're talking about serious stuff there; although, the thing that makes the frequency of the sequence low is the occurrence of the seismic event. But shouldn't there be some reference to that here? I mean, dismissing it, perhaps, as irrelevant, or saying that it doesn't -- I find it odd that we have all this detailed analysis on the one hand, and then a submittal that --

MEMBER WALLIS: Trying to mix deterministic and risk informed.

DR. APOSTOLAKIS: No, this is risk now. This is just risk.

MEMBER WALLIS: No, this is the problem of mixing them and then the application is not fully risk-informed application.

CHAIRMAN DENNING: It is definitely not a risk-informed application.

DR. APOSTOLAKIS: Well, not when you invoke 1.174. I disagree with that.

CHAIRMAN DENNING: You mean it's not risk-informed?

DR. APOSTOLAKIS: Then it becomes risk-informed.

CHAIRMAN DENNING: If you look at RS-001 --

DR. APOSTOLAKIS: Remember, you can't pick and choose. Either you're risk-informed or you're not. The moment you invoke 1.174, it seems to me you're risk-informed.

MEMBER KRESS: I'd like to comment on invoking 1.174 for containment over-pressure credit. 1.174 is for a change in the licensing basis. The plant is the same, when regulatory gives credit -- they're not changing the licensing basis. 1.174 is irrelevant for that condition. But what you should be saying is just what you said - a change in the power is a change to the licensing basis. You need to look at 1.174 with respect to that. And then if your Deltas don't meet the criteria, then you might say well, maybe we need to do something about containment over-pressure. That might be a way to get the Delta down if we stick in a pump or something, but I just don't see the connection between crediting over-pressure and 1.174.

DR. APOSTOLAKIS: That's right. I fully agree with that. I think it should be done on the real change in the licensing basis, which they claim is the first analysis that they submitted, which gives a Delta CDF of 310 to the minus seven.

MEMBER KRESS: Yes, but then again, I've

got to throw in my complaint about 1.174, that CDF and LERF are insufficient metrics.

DR. APOSTOLAKIS: Well, that original analysis was probably submitted as a supplement to the deterministic analysis, which was the real thing. But when you invoke 1.174, it's a different story. Then you scrutinize the risk assessment much more, and I don't know whether that was done or whether the PRA will change if we do that. We have the staff presenting, I believe, after these gentlemen, so maybe these questions will be addressed by them.

CHAIRMAN DENNING: George, we are going to have to address this issue. It's a very important issue. We can't address it in the detail that's needed at this meeting, just because of --

DR. APOSTOLAKIS: Which issue is this?

CHAIRMAN DENNING: What's that?

DR. APOSTOLAKIS: Which issue are you referring to?

CHAIRMAN DENNING: The one you're talking about, 1.174 and its relationship, because if you look at RS-001, which is staff guidance, for a non-risk-informed application, which this is, there are still requirements on PRA that have the nature of 1.174 in them. And we have to look at that and see if there's some generic issue here that we want to address that has some applicability to this particular plant, and its relationship to a credit on containment over-pressure.

DR. APOSTOLAKIS: I'm not sure, Rich, how stringent those requirements are. I remember from past safety evaluation reports from the staff, they would say things like the human error probability probably goes up by a little bit. We are not very sure, but after all, this is not a risk-informed application, so we're not going to pursue the issue. So the requirements are not the same. I mean, if you go through 1.174, it's a different story.

I'm not saying, again, that things will change dramatically, but we have to make sure we follow our own rules.

CHAIRMAN DENNING: Well, I think, Jack, the principal issue that I have at the moment is that we have things that we have to hear here today, and we're going to have to move forward. And if we wind up with insufficient time even on the next meeting, and we need more time, we're going to have to take more time. But as it turns out, today we have some constraints, and I'd say the absolute constraint that we have to meet is that we have a responsibility to the public this afternoon, that we don't go into their time frame of comment. And it's just that we're going to have to move on, because we've got major questions of the regulatory staff that are going to follow this on this particular issue.

MEMBER WALLIS: Well, they're hearing it now so they're going to be prepared.

CHAIRMAN DENNING: So they will be prepared.

MEMBER SIEBER: Well, it's premature to discuss any of this because the staff, to my knowledge, hasn't written an SER on it. And until they do, I think that's when we need to --

DR. APOSTOLAKIS: No, they have an SER. They don't have an SER on the latest submittal.

MEMBER SIEBER: And without that, we take the place of the staff, which we should not do.

DR. APOSTOLAKIS: No, but we are getting some useful answers though, Dr. Denning, so we're getting actually very good answers.

MEMBER SIEBER: Why don't we move on?

CHAIRMAN DENNING: Yes, and we'll move on.

MR. HOBBS: Okay. So the actions associated with our performance of the sensitivity assessment of risk included changing the Level 1 PSA model to incorporate containment leakage probability, and this included creation of a new fault tree top event designated as primary containment integrity. Secondly, we revised the appropriate Level I event trees, which include LOCAs, floods, ATWS and transients to reflect the impact of over-pressure on ECCS pump NPSH. Then we performed an uncertainty evaluation, and finally ran the PSA model to determine the impact on risk of crediting over-pressure. And one response to your question yesterday, Dr. Kress, which was asking about the late containment failure. As you noted earlier today, Reg Guide 1.174 specifies reporting the change in CDF and LERF, and we did not look at late release frequencies since that was not part of the reg guide.

MEMBER KRESS: If you considered in your PRA, though, that the reason that NPSH failed was lack of containment pressure because of a failure of containment, did you then say that's an early containment failure? Was that clear?

MR. HOBBS: Yes.

MEMBER KRESS: So that's considered an early containment failure.

MR. HOBBS: Yes. And relative to the State's desire for a different type of modeling, we believe that our approach to the sensitivity assessment was very similar to what the State had requested or thought was appropriate there, because if we lost containment integrity, we lost NPSH for ECCS pumps, and essentially the ECCS pumps failed, so it was guaranteed failure on loss of containment integrity. Same outcome.

Okay. Moving on to Reg Guide 1.174 Element Five, the ability to monitor the success of the proposed change using performance measurement strategies - the integrity of the Vermont Yankee containment is currently monitored through leak rate testing, in-service inspection, surveillances, and on-line operator indications. The maximum allowable containment leakage rate is specified in the Vermont Yankee technical specifications, and it's abbreviated here as LSFA, but that's 0.8 weight percent per day leakage. And relative to the integrated leak rate test sufficiency, our integrated leak rate test is performed at a peak containment pressure of 44 psig for 24-hours. This meets the regulatory requirements for integrated leak rate testing, and we are confident it would identify any containment integrity challenges that would result from performance of a longer test. And the duration for over-pressure credit we're asking for, which is 56 hours, relates to a peak pressure of 6.1 psi credit. So basically, the 24-hour integrated leak rate test of 44 pounds we believe is sufficient to identify any leakage that would affect the over-pressure credit request and duration.

MEMBER WALLIS: Are you going to tell us when we meet again how accurately you can measure this containment leakage?

MR. HOBBS: How accurately we measure containment leakage?

MEMBER WALLIS: Are you going to tell us that when we meet again?

MR. HOBBS: Yes.

MEMBER WALLIS: Because I'm not sure how well you can do it.

CHAIRMAN DENNING: I think there are two issues here. One is with the leak rate test, the other is how well you can --

MEMBER WALLIS: How well you can monitor --

CHAIRMAN DENNING: -- from the on-line information you have.

MR. HOBBS: Right. Two separate techniques for the monitoring.

MEMBER WALLIS: When the weather is

fluctuating tremendously and things like that.

MR. HOBBS: Right. So we'll have some uncertainty information about the integrated leak rate test.

MEMBER WALLIS: All right. And you'll tell us that.

MR. HOBBS: Yes. We evaluated the maximum containment leakage rate that could be tolerated without a loss of containment over-pressure and determined that value using the worst case design basis analysis input assumptions was 27 times the allowable tech spec limit. The as-found Vermont Yankee primary containment leakage rate has always been quantifiable, and has never approached this tolerable leakage rate. Therefore, the test result suggests that containment leakage at a rate 27 times greater than allowable is unlikely.

Drywell pressure is maintained 1.7 psi above suppression pool pressure as a result of the fact that Vermont Yankee containment is inerted with Nitrogen, and the Torus is continuously vented. Now if this pressure drops below 1.7 psi differential, a control room alarm will alert the operators. And if this condition cannot be met, the plant must be placed in a cold shutdown within 24 hours. So t his would preclude any significant time operating with drywell leakage great enough to cause a loss of containment over-pressure.

Detectible drywell leakage is essentially one-fifth of the tolerable containment leakage that would allow maintenance of containment over-pressure, so we would detect this 1.7 psi differential change at a level of about one-fifth the rate of leakage that would cause a loss of containment over-pressure. So, therefore, we believe drywell leakage would be detected at a rate substantially less than the tolerable leakage rate, and result in a shutdown of the plant within 24 hours if we had a significant drywell leak. And finally, the Vermont Yankee containment - Nitrogen consumption is monitored and significant changes would be identified and investigated.

In conclusion, in order to get the staff up here to discuss their review, the request to credit containment over-pressure meets regulatory requirements, results in a very small change in risk, and realistically would not be required.

CHAIRMAN DENNING: Any quick questions? Good. Thank you very much.

MR. HOBBS: Thank you.

CHAIRMAN DENNING: Let's proceed then with Mr. Lobel.

MEMBER WALLIS: No break? I think we need a break.

DR. APOSTOLAKIS: We need a break, Rich.

CHAIRMAN DENNING: Okay. We need a break and we will take a break. That means that we will be back by that clock on the wall at quarter of 11.

(Whereupon, the proceedings in the foregoing matter went off the record at 10:24 a.m. and went back on the record at 10:42 a.m.)

CHAIRMAN DENNING: Please be seated. We're now going to continue with the NRR's part of containment overpressure.

Because of some time constraints, at 11:30, regardless of where we are in that presentation, we are going to do the engineering inspection and complete the engineering inspection part by 12:30, and then come back to containment overpressure in the early afternoon.

Please, let's proceed.

MEMBER WALLIS: Do we have a handout for this one?

CHAIRMAN DENNING: Yes. It's from yesterday.

MEMBER WALLIS: It's from yesterday?

CHAIRMAN DENNING: It's from yesterday.

MEMBER WALLIS: I don't have it.

CHAIRMAN DENNING: You don't have it?

MEMBER WALLIS: I don't think I have anything from yesterday. Thank you.

MEMBER BONACA: Mr. Chairman? Mr. Chairman, I would like to ask a question for clarification.

CHAIRMAN DENNING: Yes.

MEMBER BONACA: For clarification, from the presentation we had from the previous engineer, the message I got is that the need for NPSH credit comes in the situation where the analysis assumes a single failure from RHR heat exchanger, plus also assumes the failure of the containment to provide isolation. Am I correct?

MR. LOBEL: No. The need for containment overpressure is due to, first of all, the higher power from the extended power uprate, and the single -- and the worst single failure, which is failure of RHR heat exchanger outlet valve. And if you have those two conditions, then you need to take credit for containment overpressure -- containment accident pressure in the deterministic analysis.

MEMBER BONACA: Well, the record has to be cleared, I think, because it's confusing --

MR. LOBEL: Okay.

MEMBER BONACA: -- in the principal intention, because I can quote a slide presented by the licensee. I mean, you know, that --

MR. LOBEL: Well, I didn't coordinate --

MEMBER BONACA: I understand that.

MR. LOBEL: -- my slides with the licensee's or --

MEMBER BONACA: Oh, no, no, no. I understand that.

MR. LOBEL: -- the state's, so --

MEMBER BONACA: I'm not placing it onto you, but I --

MR. LOBEL: I'm going to repeat some of the same information, and so we'll have a chance to go over it again. And if I'm not clear, please ask and we'll --

MEMBER BONACA: Because, I mean, he pointed out that their basic analysis -- the limiting analysis in which they're assuming the failure of the RHR heat exchanger will not need credit for NPSH if -- okay -- even with the power uprate. That's what the statement was.

MR. LOBEL: With the power uprate, the worst single failure that the licensee assumed was failure of an RHR heat exchanger outlet valve. And what they were saying is -- and the staff agrees -- is that if I don't take that as the single failure, if my single failure is failure of a containment penetration or in some other way I fail the containment so that I lose containment accident pressure, then that's -- I've taken my single failure, and now I can assume that I have two trains of RHR --

MEMBER BONACA: Okay.

MR. LOBEL: -- cooling the suppression pool. And if that's the case, then I don't need containment --

MEMBER BONACA: Okay.

MR. LOBEL: -- accident pressure credit, because my suppression pool temperature will be low enough that I'll have adequate available NPSH.

MEMBER WALLIS: So I think you're agreeing with the licensee, aren't you?

MR. LOBEL: Yes.

MEMBER BONACA: Okay.

MR. LOBEL: Okay. I'm starting on slide 5-1. My name is Richard Lobel. I am a Senior Reactor Systems Engineer in the Office of Nuclear

Reactor Regulation.

Slide 5-2. The purpose of my presentation is to discuss the NRC staff review of the Vermont Yankee proposal to credit containment accident pressure in determining available net positive suction head, or NPSH. Vermont Yankee hasn't previously credited containment accident pressure for this purpose.

Next slide, 5-3. The licensee is proposing to credit a fraction of the calculated containment accident pressure in determining available NPSH of the RHR and core spray pumps. There is no regulation prohibiting credit for containment accident pressure for this purpose.

MEMBER WALLIS: Is there any regulation allowing it?

MR. LOBEL: Well --

MEMBER WALLIS: Or is it just silent?

MR. LOBEL: No, there's no regulation that addresses it specifically, but GDC 35, for example, requires abundant ECCS flow. 10 CFR 50.46 and Appendix K talk about criteria that have to be met, that aren't going to be met if you don't have the pump flow that's credited in the accident analysis.

So, no, there isn't any regulation that

really addresses it at all.

MEMBER WALLIS: I'm just wondering, if there's nothing that prohibits it, why isn't it disallowed? Why all this fuss?

MR. LOBEL: Well, it goes to philosophy that goes back to the early days of licensing plants. Early on, some plants -- some plants of the Vermont Yankee vintage, it turned out during their licensing credit was given for containment accident pressure.

And then, the staff wrote Regulatory Guide 1.1, which essentially said that isn't such a good idea, and so let's not --

MEMBER WALLIS: But that's just a Reg. Guide, though. That's not --

MR. LOBEL: Right.

MEMBER WALLIS: -- a regulation.

MR. LOBEL: Right. And so later on when other things happened, there was Bulletin 96-03 that addressed BWR strainer blockage from debris. Some plants needed credit for it then.

There was a Generic Letter 97-04 that was issued by the NRC, I believe in October of 1997, that talked about -- that asked questions about the use of containment pressure, because the staff had found from LERs and inspections and other things that some licensees were crediting it without getting prior staff review and approval. And some licensees' analyses, NPSH analyses, were incorrect.

So the staff issued Generic Letter 97-04 about the same time as Bulletin 96-03, and the two reviews kind of got meshed together for BWRs. And in some of those cases when licensees went back and looked again at their NPSH calculations, some licensees found that they needed to take credit for containment accident pressure.

MEMBER WALLIS: Could you put it into simple words for the public? Why the NRC, first of all, thought it should sort of be allowed, and then said, "Well, that's not a very good idea, we better not allow it," and then said, "We'd better allow it, with some conditions perhaps," but then you always allowed it.

And now, you know, has anything really changed? Could you put it in simple words, so that the people that are really concerned about this issue can be sort of reassured that it really is not that big an issue or something? I mean, why is it that these regulations have sort of changed in some way about this matter?

MR. LOBEL: It was felt -- I'm not sure I can put it in simple words. I'm not sure that the thought process was that simple. But, essentially and obviously, it would be better if credit was not taken for containment accident pressure, because then there would be an extra margin in the analysis. But that's not a reason why it can't be given.

And as I'm going to get to in some detail in my presentation, these analyses have a lot of conservatism in them, and the fact that an analysis may have been done in a very conservative way initially doesn't mean that it -- it couldn't be done in a less conservative way, but still adequately conservative later on with more consideration and when there was -- I've never found another word besides "need."

But it has always been the staff position -- and I'm going to get to that, too -- that -- that the analyses are done in a safe way using conservative assumptions. And, therefore, we have never really gone back to licensees and asked them for alternatives.

So the staff position has been pretty much what I'm going to state later now, that if the analysis is done in a safe -- in a conservative way, adequately conservative way, then the staff has felt that it was acceptable to give credit for containment pressure.

MEMBER WALLIS: But all analyses in engineering having to do with reactor safety are either conservative or they are realistic with uncertainty. That's -- they all are, so it's -- so they're posing a condition that everybody always meets. It doesn't really --

MR. LOBEL: There's a difference between doing an analysis in a conservative way. For instance, a stress analysis where you put in a margin of safety, and an analysis where you take practically every variable and you add some conservatism to that variable, and you add conservatives that may not even be physically real --

MEMBER WALLIS: I don't know what this thing is -- realistic conservatism. What has changed is you're now more realistic about the conservatism? Is that what it is?

MR. LOBEL: Well, the analysis that Vermont Yankee has done isn't more realistically conservative. It's conservative. And what I was going to show is that, if I take away just some of those conservatisms, I don't need containment -- I don't need containment accident pressure credit, but

I still have a good deal of conservatism left in the calculation.

CHAIRMAN DENNING: You never use the terms "defense in depth," in all of this discussion. And in a lot of -- but a lot of the discussion around this is hinged around defense in depth and the tying of two barriers together. What's your comment on that?

MR. LOBEL: Well, like I'll show later in the presentation, it's tied back to -- if I'm talking about it deterministically, it's tied back to conservatism. If I did the analysis a little less conservatively, I wouldn't need credit for containment pressure. A realistic analysis shows that I don't need credit for containment pressure.

So in the case of Vermont Yankee -- and I'm not saying in general, I'm here talking just about Vermont Yankee -- I think there is defense in depth, because if I do the analysis in a more realistic way, I don't have to tie the barriers together.

MEMBER WALLIS: So, really, you should change the way you do things, it seems to me.

MR. LOBEL: Well, we started --

MEMBER WALLIS: Instead of saying we're going to do something very artificial, and then we're going to give credit for something we don't need, it would make much more sense to say, "You don't really need it. Therefore, this is no issue."

MR. LOBEL: I agree.

MEMBER WALLIS: That would satisfy me much more than this sort of artificially conservative, and then giving it --

MR. LOBEL: I don't think --

MEMBER WALLIS: -- you know --

CHAIRMAN DENNING: You don't have to respond to that, because it's such a global recommendation. I think --

MR. LOBEL: Okay.

CHAIRMAN DENNING: I think you probably ought to move on.

MR. LOBEL: Okay.

MR. BANERJEE: I have a question of clarification. You told Dr. Bonaca that if you lost the containment -- let's say there was a hole in the containment.

MR. LOBEL: If I take --

MR. BANERJEE: If that's just in the --

MR. LOBEL: -- if I'm making deterministic rules --

MR. BANERJEE: Yes,yes.

MR. LOBEL: -- and that's my single

failure.

MR. BANERJEE: Then, there is no way that the pumps would cavitate, and they would pump fine, because the --

MR. LOBEL: Because the suppression pool temperature would be lower, because I've taken my single failure.

MR. BANERJEE: Right.

MR. LOBEL: And I can take credit for both trains of RHR and --

MR. BANERJEE: So, effectively, there is defense in depth, because --

MR. LOBEL: Right.

MR. BANERJEE: -- it doesn't -- one failure doesn't lead to the other.

MR. LOBEL: Right. That's what I was trying to say.

MR. BANERJEE: Right. Now, what assumptions did you make about the strainer, then? Did you assume a debris bed and some sort of pressure losses there, or what did you --

MR. LOBEL: That's included. Vermont Yankee -- well, it's not my assumptions. It's what Vermont Yankee assumed in the analysis, and what Vermont Yankee did essentially was they used the analysis that was done when they installed the larger strainers as part of the resolution of Bulletin 96-03, which for people in the audience who aren't familiar, Bulletin 96-03 asks licensees to address clogging of ECCS pump strainers by debris caused by a pipe break.

MR. BANERJEE: So how much pressure loss was there across the strainer?

MR. LOBEL: For Vermont Yankee, it's very low. I think the debris head loss is in the order of .3 feet, and there's another .3 feet from the clean strainer.

MR. BANERJEE: So the calculation had -- you're going to talk about this pressure loss calculation?

MR. LOBEL: I wasn't going to. I can --

MR. BANERJEE: I'd like to hear about how you did it, so -- how it went up.

MR. LOBEL: Well --

MR. BANERJEE: Maybe in the next --

MR. LOBEL: I didn't do it. Maybe the licensee ought to address it. I mean, I can talk in general about it, and I can tell you that we -- we, the staff, wrote a letter to Vermont Yankee, I think in 1999. I'm not sure about that, but it was around that time, saying that we agreed with their approach.

MR. BANERJEE: So we can take it up later, right?

MR. LOBEL: If you want.

MR. BANERJEE: Could we deal with this in some detail in the next meeting, the 29th and the 30th?

MR. LOBEL: Yes, if the committee wants to.

CHAIRMAN DENNING: What we'll do is after this meeting we will identify all those things that we want to do at that next meeting, which are beyond possibility I know already.

MEMBER WALLIS: And it will take four days, right?

(Laughter.)

MR. LOBEL: It might be helpful if we provided you with a list of the documents, or gave you the documents, and then if you felt that you still needed to discuss it at the meeting, we could do that.

MR. BANERJEE: Yes, that definitely would be --

MR. LOBEL: We'll do that.

MEMBER WALLIS: But do it quickly. We have no time. Thanksgiving is coming up, and, you know, we're looking to work every day between now and

Thanksgiving.

CHAIRMAN DENNING: You can continue.

MR. LOBEL: Okay.

MEMBER BONACA: Yes. Just one thing that I want to, you know, raise. You were asking the question, Sanjoy, the case that's show, is on slide 11 -- is the case of a single failure RHR, her exchanger has failed, and that's the only case where they need back pressure.

To deny back pressure means that you're assuming that your containment is not isolating. So, effectively, it results in the assumptions of two failures. I mean, one is the RHR, and the other one is the containment that you are not giving credit for.

So I'm talking about the fact that effectively that is what it corresponds to in the deterministic analysis. All the other scenarios are shown that they do not need containment of a pressure.

CHAIRMAN DENNING: Yes.

MEMBER BONACA: And it's important for the record, because before I brought out the issue and it wasn't the case. It is the case, and -- and so I'll have additional questions later on about the risk analysis, whether or not it assumed the same condition or the RHR, too, but --

MR. LOBEL: Okay. The licensee --

MEMBER WALLIS: I'm sorry. I have a note here that the public needs to understand what you mean by "take credit."

MR. LOBEL: Okay. The licensee does a calculation of what we call "available NPSH." It's essentially the pressure at the suction to the pump, which forces the liquid, the water, into the pump. That value has to be above a certain value in order for the pump to operate properly, to give the flow that's assumed in the safety analyses.

In order to calculate that value, there are certain positive quantities and certain negative quantities. Some licensees just take credit for the height of water, say the height of water in the suppression pool, and that's the only pressure that's forcing water into the pump.

If the licensee finds that that's not sufficient, really, the only other place -- without changes to the system -- that the licensee can get more pressure is to take credit for the pressure over the water, in the atmosphere above the water.

And if the licensee isn't taking credit for that pressure, he assumes the pressure is zero, or the pressure is 14.7 psia. If the licensee does take credit for it, that means that the licensee is assuming some or all of the pressure that's available above the water is used in the calculation of the available NPSH.

MEMBER BONACA: Thank you.

MR. LOBEL: Did that -- is that clear?

CHAIRMAN DENNING: That was perfect.

MR. LOBEL: Okay.

CHAIRMAN DENNING: Whether it was clear is another issue.

(Laughter.)

No, actually --

(Laughter.)

MR. LOBEL: 5-4. Okay. NRC position, slide 5-4. The NRC allows credit for containment accident pressure when a conservative analysis has demonstrated that this amount of pressure will be available for the postulated design basis accident. That is, a calculation is done that minimizes this pressure over the water.

And also, when examined from a broader perspective, including design basis accidents, the level of risk is acceptable.

MEMBER KRESS: Is that an "and" or an "or"?

MR. LOBEL: I'm sorry. Did I say "or"?

MEMBER KRESS: Are you supposed to have both of these?

MR. LOBEL: Both.

MEMBER KRESS: And what do you mean by "level of risk"?

MR. LOBEL: I'm sorry. What?

MEMBER KRESS: By "level of risk," do you mean CDF and LERF?

MR. LOBEL: Yes. Yes.

MEMBER KRESS: Probably should say level of CDF and LERF.

MEMBER WALLIS: What is the vintage of this position?

MR. LOBEL: I'm sorry?

MEMBER WALLIS: What is the vintage of this position?

MR. LOBEL: Well --

MEMBER WALLIS: When did it get established?

MR. LOBEL: Actually, it's pretty much what has always been done.

MEMBER WALLIS: But you haven't written it down, right?

MR. LOBEL: But it was written down about the time that we were revising Reg. Guide 1.82 to put in the NPSH guidance which became --

MEMBER WALLIS: That is quite recent, isn't it?

MR. LOBEL: -- Revision 3.

MEMBER WALLIS: This is a clarification of the position in the last year maybe?

MR. LOBEL: It's more a documentation of a position that we've been using.

MEMBER WALLIS: But it hasn't been written down until --

MR. LOBEL: It wasn't written -- it hasn't been written down.

MEMBER WALLIS: -- this new draft Reg. Guide, is that it? Or has it been there before?

MR. LOBEL: I don't think that -- if I remember right, this isn't written in Reg. Guide 1.82, Revision 3.

MEMBER WALLIS: But it is in the new draft, is that right?

MR. LOBEL: It will be. We're going to make a lot of revisions to that before we come back to the committee in February. We're scheduled to come back to you in February and --

MEMBER WALLIS: When does it become a

hardened position, if it's in the draft now?

MR. LOBEL: Well, I suppose if it -- if we put it in the Reg. Guide, the Reg. Guide will go out for public comment, and the public and other parties -- the stakeholders will have a chance to comment on that, and --

MEMBER WALLIS: It might not be the position next year.

MR. LOBEL: Well, it might not be, but I think something along these lines would be the position.

MEMBER KRESS: I take it that that position requires a full scope PRA with uncertainty.

MR. LOBEL: I think where we are now is that it would -- we would ask licensees to do a Reg. Guide 1.174 analysis to satisfy the second part of the position.

MEMBER KRESS: Which really calls for a full scope PRA with uncertainty.

MR. APOSTOLAKIS: Well, not Level 3, right?

MEMBER KRESS: No, it never called for Level 3, which is unfortunate.

MEMBER WALLIS: So, then, you get my philosophical difficulty. How can a PRA reflect some regulation? It's got to reflect reality.

MR. LOBEL: Well, there's two parts to this. One point, the licensee still has to do the deterministic analysis, and the deterministic analysis looks at the design basis accidents and a few of the non-design basis accidents like Appendix R fire and station blackout and ATWS.

But like it says, then the broader perspective, looking at everything else that could possibly happen, would be the risk part of it. So it really covers both.

MR. APOSTOLAKIS: But when you refer to risk, you are referring to the EPU itself, right? The result of the increase in power, that's where the risk assessment will be done --

MR. LOBEL: Well, this position --

MR. APOSTOLAKIS: -- not just the regulatory part.

MR. LOBEL: This position doesn't talk about EPU. There are other things that could require the use of containment overpressure also.

MR. APOSTOLAKIS: So it's the level of risk of the reactor as is.

MR. RUBIN: Good morning. This is Mark Rubin from the staff. We have a couple issues being treated slightly differently where risk -- the word "risk" is being used. As far as taking credit for overpressure in the proposed Rev. 4 to Reg. Guide 1.82, guidance from NRC senior management, is to require that that be a risk-informed submittal, and be defended and compared against the acceptance guidelines in Reg. Guide 1.174.

With respect to the EPU as a whole, that is not a risk-informed submittal, but licensees have voluntarily included quite a bit of risk information. And from that perspective, we assess the risk from an adequate protection perspective rather than explicitly from the 1.174 acceptance guidelines, even though in reality we use the guidelines as our starting point.

CHAIRMAN DENNING: Thank you. Let's --

MR. LOBEL: Let me try to go on.

CHAIRMAN DENNING: Yes.

MR. LOBEL: Okay. Slide 5-5. The licensee credits containment accident pressure for two postulated accidents -- the loss of coolant accident and the ATWS, anticipated transient without scram.

Next slide, 5-6.

The first part of an NPSH calculation is calculating the containment conditions, and many of the conservatisms -- many of the conservative assumptions are in this portion of the calculation.

The Vermont Yankee calculation -- containment calculation for LOCA and ATWS events is done with a GE Super Hex computer code. This code has been used for containment licensing calculations for many years.

The staff wrote a letter to GE in July of 1993 stating that Super Hex was acceptable for licensing calculations in general, and it had earlier been accepted for power uprate analyses. And Super Hex has been used for all BWR extended power uprates.

The staff has previously performed independent calculations for comparison with Super Hex and obtained good agreement, and we did the same thing for the Vermont Yankee calculation. And the results are shown on the next slide for the suppression pool temperature, which is the key parameter for NPSH calculations.

MEMBER WALLIS: Could I suggest that you have a slide which extends out to 200,000 seconds like the licensee's overpressure requested credit diagram? That would -- you know, because this is all just for short time. They're requesting it out to 200,000 seconds. It would help if your diagram went that far.

MR. LOBEL: This calculation was done to

cover the point of peak suppression pool temperature.

MEMBER WALLIS: Just the peak, but, in fact, the length of time is also an issue I think.

MR. LOBEL: Well, yes. I guess -- I guess I, as the reviewer, didn't consider that to be that important. And partly because -- mainly because of the conservatisms that are in the calculation. If I take away, again, a few of those conservatisms, I cut the time that I need credit to a much shorter time.

So the point of interest in our calculation was checking the suppression pool temperature at the time where it was --

MEMBER KRESS: This is just decay heat going into a fixed amount of water?

MR. LOBEL: Right.

MEMBER KRESS: It's a pretty simple calculation. I could do --

MR. LOBEL: It's a very simple calculation, and a lot of the input came from the licensee. So that's a good point. I don't want to overdo what we did. We did use a different computer code. We did -- so that gives some assurance, and that's probably the main point -- that both codes can do the same calculation and get practically the same values.

MR. APOSTOLAKIS: So the peak temperature, according to this, is at about 20,000 seconds? Is that what we get from this?

MR. LOBEL: Yes, I believe so. I don't remember exactly the time.

MR. APOSTOLAKIS: No. I mean, not exactly, but --

MR. LOBEL: 25-, I think it was.

MR. APOSTOLAKIS: Yes. Yes.

MR. LOBEL: Yes.

MR. APOSTOLAKIS: Whether it turns around.

MEMBER KRESS: Why is there a peak? Why does it turn over?

MR. LOBEL: Because there's a balance. You're still adding energy to the suppression pool, and you're taking away that energy with the RHR heat exchanger.

MEMBER KRESS: Oh. You do have the RHR in there.

MR. LOBEL: Right.

MEMBER KRESS: Okay.

MR. LOBEL: And the RHR heat exchanger isn't sized for this situation. It's sized for shutdown. So it takes some time before the RHR heat exchanger starts to overtake the energy that you're adding to the pool.

MEMBER WALLIS: And another suggestion -- this curve is for one RHR heat exchanger.

MR. LOBEL: Right.

MEMBER WALLIS: If you put two on, then you could show what you get for temperature then, which is more realistic.

MR. LOBEL: We tried to do that, but we didn't have enough information to do that calculation without going back to the licensee. And since this was the design basis case, we just did this case. But the licensee before talked about the value they got with two, and I'm going to talk about that some more -- with two heat exchangers.

MR. THADANI: Okay. Rich, before you go on, the two accident sequences you talk about are LOCA and ATWS. And you were saying analyses were conservative. I don't seem to recall ATWS analyses being done in a conservative way.

MR. LOBEL: You're right. ATWS analyses don't have to be done in a conservative way, but the licensee did put some conservatism into the calculation. And off hand, I can't think of what they are, but -- but the licensee, I think in a July 2, 2004, letter, gave us some tables with a list of their assumptions for the different analyses.

And if you look at those, you can see that some of the assumptions that they used were conservative, and they didn't -- you're right, they didn't have to do that.

MEMBER KRESS: Is this the ATWS curve or the LOCA curve?

MR. LOBEL: This is a LOCA. This is the large break LOCA.

MEMBER WALLIS: We need to discuss ATWS with you or somebody in detail next time we need with the staff. Perhaps not here, but we do.

CHAIRMAN DENNING: Okay.

MR. LOBEL: Okay. As you can see, the agreement is good. We just talked a little bit about that.

Slide 5-8. In addition to those two events -- LOCA and ATWS -- the licensee originally proposed containment accident pressure for Appendix R fire and station blackout events. The licensee later changed their analysis to eliminate the need to credit containment accident pressure, and they did that by crediting a second service water pump in each train of service water, and the service water is what cools the RHR heat exchanger. So they essentially added more flow through the RHR heat exchanger.

The licensee used the GOTHIC 7 computer code to calculate the containment conditions for the Appendix R fire event and the station blackout. GOTHIC is developed for EPRI. It's subject to Appendix B and Part 21. The staff uses GOTHIC in reviews for sensitivity studies.

The code is very widely used in the industry. The staff asked the licensee some questions about the use of GOTHIC. There is an NSER that we put out, which essentially provides guidance on the use of GOTHIC after a pretty detailed review of the licensing basis containment models, and the licensee said that they used it in accordance with that SER.

Also, the licensee complies with Generic Letter 83-11, and 83-11 Supplement 1, which are guidance documents for utilities that want to use large, complex computer codes that have been usually approved by the staff. And the point of the Generic Letters is the codes may be okay, and they've been benchmarked and found acceptable, but we want to be assured that the licensee has the capability to use those codes properly.

And the licensee responded to a question describing how they complied with the Generic Letter that we found acceptable.

MEMBER RANSOM: Is the ATWS case worse than the large break LOCA?

MR. LOBEL: No. The large break LOCA is the most limiting event.

The next slide, 5-9, gets into what the state was talking about before -- required NPSH. As you know, there are two types of net positive suction head, NPSH, the available that I discussed a little before and the required NPSH, which is a function of a pump design. And it's determined by testing the pump.

The licensee's NPSH calculations use a required NPSH that's different from the usual definition in the Hydraulics Institute standards. The standard approach, as shown on this figure, for determining required NPSH of the pump -- the figure is a plot of the head increase generated by the pump as the vertical axis, and it's called the total head.

So, again, this is the energy that the pump is producing. So this is the desired product of the pump.

MEMBER WALLIS: What is the pressure it's producing?

MR. LOBEL: Hmm?

MEMBER WALLIS: What is the pressure it's producing?

MR. LOBEL: Pressure, right. Well, the centrifugal pumps --

MEMBER WALLIS: Energy is something else. It's the pressure.

MR. LOBEL: -- centrifugal pumps, you talk in terms of head. The --

CHAIRMAN DENNING: Okay.

MR. LOBEL: I'm sorry. Maybe I missed the question.

MEMBER WALLIS: No. This is pressure after delivery of Q2.

MR. LOBEL: Okay. Yes. Okay. So the figure shows the head generated by the pump as a function of the available NPSH. And what's done in the testing is the flow rate is set to a constant value, and the NPSH -- the available NPSH is lowered until you get to a point where the -- where the head experiences a drop of three percent.

The drop in heads caused by cavitation in the pump, the value of NPSH at which this three percent drop in head occurs, is the usual definition of a required NPSH. In an actual system, such as a core spray pump in a BWR, the usual criterion for acceptable operation is that the available NPSH be equal or greater than the required NPSH to avoid excessive cavitation.

The licensee uses values of NPSH in some analyses which correspond to a head loss greater than three percent. The maximum value is approximately six percent. So the intensity of the cavitation is increasing as the required NPSH drops.

MEMBER WALLIS: Now, the back pressure on this is very small, isn't it? The back pressure from the -- from the -- because, really, you have to -- do you have to tie this in with the impedance of the delivery system, because there's a feedback. If you lose head, you change the flow because of the characteristics of pressure flow of where it's going. So you need to have a load --

MR. LOBEL: And this is done --

MEMBER WALLIS: -- curve or something on here.

MR. LOBEL: This is done in a test loop.

MEMBER WALLIS: All right.

MR. LOBEL: And so the available NPSH is calculated for that test loop.

MEMBER WALLIS: But, in reality, if you have, say, a pump in your basement from a low -- a well or something, and it begins to do this, you can get to the point where the flow falls off the cliff and goes to zero, and the pump just heats up.

MR. LOBEL: Right.

MEMBER WALLIS: Because it's a stability question, not just a question of NPSH.

MR. LOBEL: Well, the idea is that -- that you don't let the pump get to that --

MEMBER WALLIS: Yes.

MR. LOBEL: -- to that point.

MEMBER WALLIS: You don't let it get to that point.

MR. LOBEL: And the usual drop of three percent is done so that you're on the very top of the knee of the curve. You aren't getting to the point where the flow and the head have dropped off to essentially nothing.

MEMBER WALLIS: But if you drew the head flow characteristics of the load it's pumping to on top of this, you'd get a stability criteria, which might or might not correspond to three percent. It would be an intersection of two curves, whether they're tangential or not --

MR. LOBEL: Right.

MEMBER WALLIS: -- which, really, you

should do. I mean, this is more --

MR. LOBEL: Right.

MEMBER WALLIS: -- I would like to see it. It's a much more rational way of explaining why the pump doesn't work. There's nothing magical about three percent.

MR. LOBEL: There's nothing --

MEMBER WALLIS: But anyway --

MR. LOBEL: -- magical about it. It's chosen because at a level of three percent there is assurance for low and moderate energy pumps that the pump won't experience any damage. And also, it's about the level where you can actually measure a head drop. Anything less than that it gets harder to measure the drop in head.

Well, the licensee uses curves developed by the pump vendor, which permit operation at lower values of required NPSH for limited amounts of time. The Vermont Yankee RHR pumps are permitted to operate with a loss of head of approximately six percent for seven hours.

Then, the value of required NPSH ramps up to close to the three percent head loss value at 100 hours, and then stays constant from 100 hours to essentially 8,000 hours. They call it the value of the 8,000-hour value of required NPSH, which is about 333 days.

MR. APOSTOLAKIS: Would you explain the figure a little better? What are Q1 and Q3? And what's the meaning of --

MR. LOBEL: It's just different flows.

MR. APOSTOLAKIS: So Q1 is --

MR. LOBEL: It's different values of volumetric flow.

MR. APOSTOLAKIS: And the arrows, what do the arrows mean?

MR. LOBEL: The arrows are pointing to the value of head where you've had a drop of three percent from the horizontal line. So that would be -- that would be the required NPSH value. You would lower the available NPSH to the point where you started to get cavitation at a three percent head drop. That would be the value of required NPSH the way things are normally done.

MR. BANERJEE: Let me just ask you -- so for different -- if you have a pump characteristic, clearly the head varies with the flow rate.

MR. LOBEL: Right.

MR. BANERJEE: So the NPSH varies with the flow rate as well.

MR. LOBEL: The required NPSH does, right.

MR. BANERJEE: It varies, so --

MR. LOBEL: Right.

MR. BANERJEE: -- I guess --

MR. LOBEL: And you can see that in the figure. You can see that when you vary the flow rate --

MR. BANERJEE: Right. So Q1 is smaller than Q2 is smaller than Q3.

MR. LOBEL: Right.

MR. BANERJEE: On this, right? So you have a cubic curve or something, which gives you head versus flow. How does the NPSH vary? Is it just in proportion to this, or is there --

MR. LOBEL: The required NPSH increases with the flow.

MR. BANERJEE: Right.

MR. LOBEL: Which is one of the conservatisms that's included in these calculations. As the flow increases, the required NPSH increases.

MR. BANERJEE: So there's a curve of NPSH versus flow.

MR. LOBEL: Right.

MR. BANERJEE: Okay. So when you say this NPSH is required, it's for a particular flow.

MR. LOBEL: Right.

MR. BANERJEE: So how do you know exactly what that flow is? You have to do a calculation, right, for that flow?

MR. LOBEL: Well, this is where you would get the -- the required NPSH as a function of flow, from this kind of test. The available NPSH you get from whatever system the pump is in, and that's going to vary with flow because the resistance is going to -- the flow resistance is going to change the flow.

MR. BANERJEE: Yes. So as your flow goes up, the NPSH required goes up.

MR. LOBEL: Right.

MR. BANERJEE: So at a high flow you need a much higher NPSH.

MR. LOBEL: Right.

MR. BANERJEE: So when you say this NPSH is required for this system, that's based on a particular flow, right?

MR. LOBEL: Well, I'm not saying it's required for a system. Required NPSH is the term of art that's used for the -- as a characteristic of the pump.

MR. BANERJEE: But at what flow?

MR. LOBEL: Well, it's going to vary with flow. As you can see, on this simple curve, it's --

MR. BANERJEE: Yes. I can see it will vary with flow, but what is the flow that you use to say that NPSH is required?

MR. LOBEL: Well, I'm going to get to that.

MR. BANERJEE: How do you do that?

MR. LOBEL: I'm going to get to that a little later.

MEMBER WALLIS: You see, that's where you have to do what I was saying. If the operator throttles this thing --

MR. LOBEL: Right.

MEMBER WALLIS: -- it changes the NPSH, because --

MR. LOBEL: Absolutely.

MEMBER WALLIS: -- it depends on the pressure drop characteristics of whatever it's bumping into.

MR. LOBEL: Of the system, right.

MEMBER WALLIS: Which you can change by throttling and all that sort of thing.

MR. LOBEL: Right.

MEMBER WALLIS: It's not a simple thing like just looking at one curve and three percent.

CHAIRMAN DENNING: Let's continue on, and then you can --

MR. LOBEL: Okay. All this is supposed to show is how I get required NPSH.

MEMBER SIEBER: Let me ask you a quick question. In the Hydraulics Institute standard, it talks about basically three grades of -- three types of pumps -- low energy, high suction energy, and very high suction energy. These pumps are in the high suction energy category.

MR. LOBEL: The licensee stated in response to a question that -- they called it moderate, and it's -- it's -- I believe it's -- maybe they can help, but I believe it's above low, but not a whole lot above low.

MEMBER SIEBER: Well, the standard only has three.

MR. LOBEL: Right, right. So it would be high, but --

MEMBER SIEBER: In the cavitation characteristics, they're distinctly different from one to the other.

MR. LOBEL: Right. But these pumps would still be in the suction energy range, where you wouldn't expect a lot of damage. You wouldn't expect damage from operating the pump in cavitation for a length of time.

MEMBER SIEBER: At about -- even at six percent below the --

MR. LOBEL: Right.

MEMBER SIEBER: -- the flow level.

MR. LOBEL: Right. And --

MEMBER SIEBER: Well, the standard says that, so --

MR. LOBEL: Yes. And that's consistent -- their six percent is consistent with other industry experience for safety-related nuclear pumps. Okay.

MEMBER SIEBER: And these are vertical shaft --

MR. LOBEL: Yes, single stage.

MEMBER SIEBER: -- down in the well

MR. LOBEL: I believe they're single stage, right.

MEMBER SIEBER: Okay. Thanks.

MR. LOBEL: Right. Okay. Slide 5-10. Let me go through this a little faster.

MEMBER WALLIS: This is probably oversimplistic -- I mean, the required NPSH -- because if the operator throttles, he can get into an operation mode where it's still -- the pump still works. He just gets less water. And the question is: is that out of -- NPSH isn't only part of the whole question. You can't just have a magical required NPSH. You have --

MR. LOBEL: And I was --

MEMBER WALLIS: -- the pressure in the vessel and everything.

MR. LOBEL: And I was going to talk about that under conservatism later. But you're right, if I lower the pump flow, I lower the flow resistance, the available NPSH goes -- goes up, and the required NPSH goes down. So I've increased the margin between the available and the required.

MEMBER WALLIS: Both things help you, right?

MR. LOBEL: Right. Right. Okay. One of the positions in Reg. Guide 1.82, Revision 3, is that the prototypical pump test should be performed, and there should be a post-test examination of the pump to show acceptable results, if the licensee is crediting required NPSH of more than the three percent value. It's not that clear in the Reg. Guide. That's another thing that's going to get fixed.

MEMBER WALLIS: Well, let me say, as a Vermont, they used to have a lower head -- a spring.

Any Vermont who has a spring down below his house knows that when the level gets low he might get cavitation in his pump, and the cure is to go down and throttle it, and you just get a little less water and you can still survive for a while that way.

MR. LOBEL: Right. And --

MEMBER WALLIS: You know, even -- I think even some members of the public here would understand what you're talking about on that basis.

MR. LOBEL: And the assumption that's made in these conservative analyses is the pumps are either in runout or at design flow. So you would expect the operator to throttle the pumps, even without signs of cavitation, if he had that condition.

MEMBER RANSOM: Do you know if the system models include the pump characteristic cavitation factored into the pump characteristic?

MR. LOBEL: I can't answer that question. I don't know.

MEMBER SIEBER: I think when you set the pump characteristics, the operating points for the pump, there is some amount of cavitation assumed.

MEMBER RANSOM: But, in general, you put in the full pump characteristic -- you know, head versus flow at different speeds --

MEMBER SIEBER: Yes.

MEMBER RANSOM: -- and usually they put a cavitation model on it using suction-specific speed as the parameter.

MR. LOBEL: Well, I don't think -- I don't think -- if the licensee would like to address that or if you can do that later.

MEMBER RANSOM: If you do the calculations, then you could share what level of cavitation a given calculation --

MR. LOBEL: Well, I think the usual assumption that's done in the safety analyses is you have whatever flow you need. And then, if -- and that assumes adequate required NPSH.

MEMBER RANSOM: No cavitation.

MR. LOBEL: No cavitation. And then, you do these NPSH calculations to assure that you're going to have that level of available NPSH, required NPSH, so they are really two separate calculations.

MR. BANERJEE: So is it possible to throttle these pumps back if the flow is too high?

MR. LOBEL: Yes. Yes.

MR. BANERJEE: So you can do that.

MR. LOBEL: Right. The operator can do that.

MR. BANERJEE: If it starts shaking or something, you can go and do something about it.

MR. LOBEL: If the operator has indications of cavitation -- and like was said earlier, he has curves in the emergency operating procedures of suppression pool temperature, pump flow with containment accident pressure as a parameter. And that's how he would -- he would make sure that he has adequate NPSH.

MEMBER WALLIS: And the cost of the LOCA if you have -- if you throttle back enough on your core spray, and then you start to affect the containment pressure, because you're not cooling things so well. And then, you've got too high a pressure rather than too low a pressure. Everything is tied together in this.

MR. LOBEL: Right.

MEMBER WALLIS: Which is why a realistic PRA, coupled with realistic thermal hydraulics, would make a lot of sense, instead of all of this artificially -- doing things here and there.

CHAIRMAN DENNING: Regrettably, we're going to have to interrupt this presentation at this point, and we'll come back after lunch with this presentation. And we're now going to move to engineering inspection, and we have to complete that in the next hour.

So, please, would the engineering inspection people -- oh, I'm sorry. And we don't believe that we really need a presentation by Entergy. At this point, we're going to move directly on to the staff's presentation.

If you're ready, please go ahead.

MR. DOERFLEIN: We're on slide 7-1. Good morning. My name is Larry Doerflein, and I'm an Engineering branch chief in the NRC Region I office. I'm here today with Jeff Jacobson and Rick Ennis to discuss the 2004 Vermont Yankee engineering team inspection.

Jeff was the inspection team leader, and Rick is the project manager for Vermont Yankee.

We intend to cover four topics during our presentation. I'll briefly discuss the inspection background, or basically why we did the inspection we did. Jeff will discuss the details of the inspection and the results. That will be followed by a discussion of what inspection followup we have done since the team inspection, and Rick will discuss the impact of the inspection findings on EPU amendment review.

At this point, I'll ask if there's any questions before I continue.

MR. APOSTOLAKIS: Do you feel the need for asking us whether we have questions?

(Laughter.)

MR. DOERFLEIN: I'm new to this.

(Laughter.)

Next slide.

I'll start by noting that the biennial safety system design and performance capability inspection was scheduled for August of 2004. That was scheduled about 18 months in advance and is our baseline design team inspection, which uses about 475 inspection hours to review one or two systems.

I mention it because it set the timing of whatever inspection we would do, and this was one of the options we initially considered staying with, even as various stakeholders began requesting a special inspection prior to approval of EPU amendment requests.

In particular, in March 2004, the Vermont Public Service Board, PSB, asked the NRC to conduct an independent safety assessment of Vermont Yankee. Specifically, the PSB requested the inspection be performed by experts independent of any recent regulatory oversight of Vermont Yankee. The assessment included review of two safety systems and two non-safety systems affected by the uprate, and that the inspection results be reviewed by the ACRS.

I think I would like to point out at this point that the PSB did not specifically request an inspection the size and scope of what was done at Maine Yankee. In their request, they indicated that they had received testimony that they thought what they were asking to review the four systems could be done by four people in four weeks, which equates to about 640 inspection hours. I give that as a comparison, and you'll see what we actually did do.

CHAIRMAN DENNING: In the Maine Yankee, how many inspection hours was that?

MR. DOERFLEIN: I don't have a total. It was thousands, probably close to 2,000.

CHAIRMAN DENNING: Thanks.

MR. DOERFLEIN: Nonetheless, as a result of the PSB request and other stakeholder comments, we did discuss the option of performing an inspection at Vermont Yankee similar to the Maine Yankee independent safety assessment. However, we determined that the conditions at the two plants were different, and that this option was not warranted.

Specifically, at Maine Yankee there were allegations of the licensee misrepresenting a computer analysis in a 1989 license amendment request, as well as an Inspector General investigation regarding deficiencies in other past licensing actions. This caused the NRC to have significant concerns with Maine Yankee's conformance to their license requirements.

In addition, the Governor at the time requested a special review of Maine Yankee, and the problems at Millstone were starting to surface regarding compliance with the design requirements. And with all of this -- all of this led Sherman Jackson to call for the independent safety assessment at Maine Yankee.

This was a customized inspection, the size and scope of which were determined by the circumstances. In contrast, there was not a similar situation at Vermont Yankee. This was based on a couple of factors, one of which was the fact that the plant had received significant engineering inspection since 1996. Most notably, it was one of the four plants in Region I to receive an architect-engineer team inspection in August of 1997.

In 1998, there was an engineering team inspection to follow up on the issues from the AE team inspection, as well as look at configuration management. In 1998, there was also a baseline core engineering team inspection.

Under the current reactor oversight program, there have been two safety system design and performance capability team inspections -- one in 2000 and one in 2002 -- as well as two plant modification inspections. So there has been a lot of inspection.

Some of the other factors that we considered dealt with the fact that there were not integrity issues at VY that we saw at Maine Yankee that led us to lose confidence in Maine Yankee. And at VY we were actually in a formal process.

We are reviewing an amendment request, which is going to take thousands of hours of staff review to determine whether this plant was ready for proceeding to EPU conditions. So we thought, based on that, a Maine Yankee type inspection was not required.

Another option considered, and ultimately chosen, was to perform the new inspection procedure being developed to enhance our engineering inspection. The new procedure incorporated the best practices of existing and past engineering inspection procedures.

The new procedure was under development since late 2003, and we determined it would be appropriate to implement the inspection procedure at Vermont Yankee as part of an agency pilot program.

Basically, it gave us much more inspection activity, considered margin reductions that could be caused by power uprates, and was within our process, without getting --

MEMBER WALLIS: Can I ask a question about this?

MR. DOERFLEIN: Sure.

MEMBER WALLIS: We had a lot of questions from the public yesterday about the extent of the inspection. They seem to have the impression that it only inspected a very small percent of what might have been inspected. Maybe you could explain this and why the amount inspected was a reasonable fraction of what could have been inspected, why this was adequate, and so on, because this was a main issue -- a major issue yesterday.

MR. DOERFLEIN: That is actually part of Jeff's presentation.

MEMBER WALLIS: So we will hear that?

MR. DOERFLEIN: Yes.

MEMBER WALLIS: Okay. Thank you.

MR. DOERFLEIN: Without getting into Jeff's presentation, the new procedure called for an inspection and components across multiple systems, about 50 percent more inspection time, and the use of more contractor support. And, again, at Vermont Yankee, we actually doubled the estimated inspection time.

In staffing the Vermont Yankee inspection, the NRC established specific criteria to ensure independence of the team. These criteria applied to NRC contractors as well as the inspectors.

We believe this, combined with the fact that we would look at components of multiple system, including some impacted by the power uprate, address the PSB's concerns.

Lastly, I want to point out that the Vermont State Nuclear Engineer did participate in all team activities, and this is something that we promised not only the PSB but others that we would do.

That concludes my background discussion. And unless there's any other questions, I'll turn it over to Jeff.

MR. APOSTOLAKIS: What exactly was the nature of his participation? Was he just an observer or --

MR. DOERFLEIN: He was an observer. He participated in all team discussions. He could answer it himself.

MR. SHERMAN: I did participate. And I had no direct inspection responsibilities, but I was able to be with the team, ask questions of the licensee on various issues, and actually was able to participate much like a full member of the team.

CHAIRMAN DENNING: And that was Bill Sherman.

MR. APOSTOLAKIS: But you did not participate in the decision of how much to inspect.

MR. SHERMAN: That is correct. I did observe how that process was done, and I also had some input through the fact that the state was concerned about various items related to power uprate, which in the process we saw that they were included in the scope.

MR. APOSTOLAKIS: Thank you.

MR. DOERFLEIN: Any other questions? Jeff?

MR. JACOBSON: Good morning. As Larry said, my name is Jeff Jacobson. Was the team leader for the Vermont Yankee engineering inspection. What I'm going to try to cover this morning is a little bit about the background of the inspection and the scope, and I'll focus on some of the questions that have been raised regarding the amount of things that were looked at, and so forth.

I'll talk a little bit about the methods that we used during our inspection. And then, lastly, I'll cover each of the inspection findings that were identified by the team. Following my presentation, Larry and Rick will talk about what was done after the inspection with respect to each of the inspection findings.

My responsibility, essentially, ended upon the completion of the inspection. It's up to the region and the NRR tech staff to follow up on the issues that were raised with regard to how they impact current operability in the power uprate.

Next slide.

We believe the inspection that we did was responsive to the Public Service Board's request to conduct an independent assessment.

MEMBER WALLIS: The real thing is: did they think it was responsive?

MR. JACOBSON: Well, they'll have to speak to that.

MEMBER WALLIS: Can they speak to it now, or do they want to speak to it later? Did this respond to what you were looking for?

MS. HOFMANN: Sarah Hofmann from the Department of Public Service. We're the Department, not the Board, so I won't speak for the Board. But the Board is actually interested. They wanted to make sure that ACRS saw this inspection report and have not ruled on whether it met the requirements of what they asked for. The Department believes it did.

MEMBER WALLIS: Okay.

MR. JACOBSON: The inspection that we did at Vermont Yankee was part of a pilot program that was begun just prior to the Vermont Yankee inspection to improve the effectiveness that we do -- in which we do engineering inspections. It was an initiative that came out of Commission that directed us to take a look at how we were doing engineering inspections and try to identify ways to improve their effectiveness.

And it largely resulted out of some of the concerns that came out of the Davis-Besse plant and some other facilities that had undergone lengthy shutdowns as a result of engineering issues. So we were asked to look at our approach and see if we could do these inspections more effectively.

I was the project lead for that initiative to look at these inspections, and we had developed a draft inspection procedure just prior to the issues that came up with Vermont Yankee. And we decided that the Vermont Yankee facility would be a good first test of this new draft inspection procedure.

We wound up doing one of the inspections in each of the regions, and then we did an assessment. And I'll talk a little bit more about where we're going with that in a few minutes.

As Larry said, the inspection that we did involved about 900 hours of direct inspection versus 475 hours which we would have spent had we done the normal engineering team inspections that --

MEMBER WALLIS: Is this because there were twice as many people, or you did twice as much work?

MR. JACOBSON: Well, it was more -- it was more people and more time.

MEMBER WALLIS: And more time. So the normal inspection is -- it was eight or nine people with this inspection?

MR. JACOBSON: We added an additional week to the inspection, and then we also had additional people beyond what would have been done had we done the normal team inspection.

Next slide.

I was the team leader. We also had four regional inspectors and three highly qualified independent contractors. And we specifically chose the team members and the contractors based upon past performance and their ability to have identified findings at other inspection sites. So we really tried to staff this team with some of the best people that were available to us, both from an NRC inspection perspective as well as a contractor perspective.

As Larry said, all of the team members were independent of any recent oversight responsibilities at Vermont Yankee.

MEMBER WALLIS: The public was very concerned about independent inspection. It would seem to me that it would be very difficult to pick anybody who is not familiar with these plants and didn't know inspection procedures who could do the work. So you are sort of restricted to picking people who are knowledgeable. You can't just go out and pick some engineer off the street to inspect these things. So the --

MR. JACOBSON: Well, the --

MEMBER WALLIS: -- independence has got to be within a very small community of people.

MR. JACOBSON: Well, there's various levels of independence. We chose a level that, like you said, was a balance between people that were capable enough to do a decent inspection, but, again, did not have recent oversight activities at Vermont Yankee.

I was not in Region I. I was in NRR, so I didn't have any responsibilities with Vermont Yankee, had never done an inspection at Vermont Yankee. So that's an example. If somebody -- the contractors had not done inspection activities at Vermont Yankee, and the regional inspectors had not done any recent engineering inspections.

So there is -- we tried to get the best balance we could between true independence and capability to do an effective inspection.

MR. APOSTOLAKIS: Do these contractors work for you usually, or are they also working for the industry?

MR. JACOBSON: The contractors that we use, we have a contract with Beckman and Associates that provides us --

MR. APOSTOLAKIS: Okay.

MR. JACOBSON: -- contractors. They are free to take jobs for utilities. But for this particular job, we added additional conflict of interest requirements beyond those that are normally in place that prohibited them from having -- doing previous work at the utility, at Vermont Yankee, and also applies to future work that they may have to do.

So we normally have conflict of interest requirements. For this particular inspection, we added on this, just to address this question of independence.

The inspection focused on components and operator actions that represented the most risk and also had the lowest relative safety margins. So the idea behind this inspection concept was to not just look at things that are important from a risk perspective, but to also consider where the most vulnerabilities exist with respect to the design.

MR. APOSTOLAKIS: I'm a little confused about the operator actions, because I heard this morning that the operators don't need to do anything. Is that -- what are the operator actions that are of relevance here?

MR. JACOBSON: Well, there's various different accident scenarios that are part of the design basis.

MR. APOSTOLAKIS: Oh.

MR. JACOBSON: Some require more operator access than --

MR. APOSTOLAKIS: Oh. So it's not -- I

mean, maybe I misunderstood a statement earlier this morning. Maybe they meant there were no additional --

MEMBER WALLIS: No. This is a much broader inspection than --

MR. APOSTOLAKIS: I understand. There were no additional operator actions as a result of the EPU.

MR. JACOBSON: Right.

MR. APOSTOLAKIS: But there are clearly operator actions required at the -- okay.

MR. JACOBSON: I think the statement this morning was directly related to the design basis accident with regard to containment overpressure. And in that regard, they were saying there was no additional operator. But they were still required to maintain --

MR. APOSTOLAKIS: Right.

MR. JACOBSON: -- the pressure within those curves.

MR. APOSTOLAKIS: So can you give me an example or two of operator actions that you looked at?

MR. JACOBSON: I'm going to give you an example, because one of the findings we had was directly related to that.

MR. APOSTOLAKIS: Okay.

MR. JACOBSON: The way we did this inspection is the first phase of it is really to figure out where the low margin/high-risk areas are. And then, once those are identified, the remainder of the inspection is focused in on those areas. So it's really a two-phased inspection.

And when we talk about margin, I wanted to expand upon that a little bit, because it's not just design margin or calculation of margin, but it includes other factors such as physical degradation, which is based on our visual walkdowns of the plant.

It includes looking at past maintenance histories for particular components, such that if there was a history that there had been a lot of failures with a certain component, that would certainly cause us to put it into more low margin area than a component that is -- had no problems in the past.

MR. APOSTOLAKIS: Has Vermont Yankee asked for license extension?

MR. ENNIS: This is Rick Ennis. They have provided a letter that said they're planning on submitting it in January.

MR. APOSTOLAKIS: Right.

MR. JACOBSON: And we particularly looked at the areas of the plant where the margin would be reduced as a result of the power uprate, and that comes into play very much so with regard to some of the operator actions. We'll talk a little bit more about that.

MEMBER KRESS: How did you decide what were high-risk components?

MR. JACOBSON: We used the licensee's PRA. We also used our own SPAR models, used risk achievement worth profiles, and so forth.

MEMBER WALLIS: Are you going to go into all of your findings, or just a few?

MR. JACOBSON: We have eight findings, and I'm going to briefly touch on them all.

MEMBER WALLIS: I'm particularly interested in this one about the 21.3 minutes.

MR. JACOBSON: The operator time.

MEMBER WALLIS: Because I think some of the other ones are less -- less relevant perhaps.

MR. JACOBSON: I'll try to focus on that one.

We looked at 45 components, operator actions, and operating experience samples. So that inspection is broken up between components, operator actions, and then we also looked at generic-type issues that had been communicated to the licensee in the past. And we reviewed their disposition of those issues.

For example, periodic testing of motor-operated valves was a generic issue that we looked at, an issue that we had a finding on. I'll talk a little bit about that.

The components that we reviewed were not limited to any one specific system, but just the way it came out they tended to be grouped more or less in several important systems that are important from a risk perspective and are also the systems that are impacted most by the power uprate.

And those include the onsite and offsite electrical systems, the reactor core isolation cooling system, the residual heat removal system, the safety relief valves, reactor feedwater and condensate system, as well as other risk-significant systems.

In doing our inspection, we looked for visual signs of degradation, installation errors, interference issues, environmental concerns. We reviewed the applicable design and licensing basis documentation, evaluated assumptions that went into each of the design calculations that we looked at, system interfaces, different failure modes that could occur.

We looked at the component history, including maintenance, corrective action, and testing records, associated operating procedures, and we tried to focus on the functionality of the equipment.

We also evaluated certain operator timelines and compared those to real-time operator actions. So we actually took some design basis operator actions and walked through the plant with the operators and had them demonstrate to us that they could perform the actions in the time that was credited in the calculations.

The Vermont Yankee inspection was a little unique, because we were really looking at the plant with respect to two design bases -- the one that was in existence at the time with 100 percent power level. But we also looked at, would the equipment be adequate for the extended power uprate conditions, even though those conditions weren't in place at the time.

So, in many cases, we looked at two different sets of calculations for the same components and actions. And in some cases, they are very close. In other cases, the power uprate has more of an impact.

We also assessed the design control

process that was used for Vermont Yankee in doing the power uprate. So for some of the components we actually walked through the design control process back to the actual vendor that did the work, and then how the licensee scoped it in, and so forth, to assure ourselves that there was control of the process throughout the different parties that are involved in actually scoping and implementing the power uprate analysis.

The inspection identified eight findings of very low risk significance, which are colored green based on our reactor oversight process. The findings did not result in any immediate system inoperability, nor would they have resulted in system inoperability, had we done this inspection once the power uprate had actually taken place.

We also did not believe that the findings were indicative of any programmatic breakdown.

MEMBER WALLIS: Well, you said that it wouldn't result in any failure to perform, whatever the terms were you used. But you had this business of the inadequate -- you hadn't done any coping analysis, so how do you know that things would have worked if they hadn't actually looked at it for this electrical issue? I mean, you say that there's no -- there's no problem. But if you hadn't done anything, how do you know it's okay?

MR. JACOBSON: Well, at the time we identified it, we didn't know, but before the end of the inspection we made them -- or we didn't make them, but we -- we brought the issue to their attention that there was not an adequate coping analysis. And we did a draft coping analysis before we actually left the site, which gave us comfort.

MEMBER WALLIS: So they did things after you were there, which reassured you, but to state that you found it, it was not quite so good.

MR. JACOBSON: Right. They did things while we were there and after we were there to address some of the issues.

We looked at the extent of condition, which is an art term, in three areas for some of the findings to make sure that the findings were not indicative of bigger concern. So some findings were clearly isolated cases. Others could have been indicative of broader concerns. And in those cases we pulled a string and reviewed additional samples to make sure that there was not a bigger programmatic concern associated with those findings.

To talk a little bit about the inspection approach that we used and how it was different than things we had done in the past -- in the past, our inspections have always focused on one or two safety systems.

We would pick the most risk-significant systems and then we would inspect just about everything in that system to prove that that system was functional, whereas in this approach we really try to focus throughout the plant on where we believe the plant is most vulnerable and where the lowest margin areas are.

And when we finished our pilot inspections, we really -- we did an assessment. We brought all the people that were involved in the pilots, the regional people, the contractors, and we really decided that this new approach was, in fact, more effective than the inspection approaches that we had done in the past. And we --

MEMBER WALLIS: Again, this is important for the public. I mean, yesterday we heard about there's great need for a vertical slice inspection.

MR. JACOBSON: Right.

MEMBER WALLIS: And you have done an inspection which you believe is more effective than doing that.

MR. JACOBSON: That's why I wanted to focus on this. It's not just engineering judgment. We looked at other factors such as the risk significance of the aggregation of the findings that came out of these pilots, the number of findings per inspection hour that was spent during these inspections.

In all cases, we determined that the pilot inspections were more effective than the previous baseline inspections. And, in fact, one of the pilot inspections at the Kewaunee facility actually resulted in that plant shutting down due to some of the issues that were raised until they could rectify the issues that were identified by the inspection.

And that situation had not occurred in the previous four years where we had done engineering inspections throughout the country. So we really have a lot of faith in this new approach, and we plan on implementing it nationwide starting the first of next year. So it is going to take the place of what we had previously done.

I'm going to talk briefly now about each of the eight inspection findings. I'm assuming that you've had a chance to read the inspection report, so I'm not going to go into a lot of detail about each one. But if anyone has any questions, I'll try to elaborate on it.

The first finding, which is probably the issue we spent the most amount of time on, involved questions concerning the capability of the Vernon hydroelectric station to supply power to Vermont Yankee in the event of a regional blackout. The inspection team identified that Entergy had not provided assurance that the Vernon station could be brought back online within the time assumed in its coping analysis.

The issue was very complicated because these -- if this situation occurs, there's a lot of different players that have to coordinate their actions in order to supply power back to Vermont Yankee.

So it's not limited just to the Vermont Yankee licensee, but you've got the people that operate the Vernon station, you've also got the regional grid operator who controls the switchyard at the Vernon station, and all of those people need to coordinate in a proper way to make sure that the actions that are credited in Vermont Yankee's station blackout analysis can actually occur.

MR. LEITCH: Is this -- the Vernon station is not continuously manned, correct?

MR. JACOBSON: The Vernon station is not now. At one time it was continuously manned, so the conditions actually changed over the years. Now it is not continuously manned, and if the regional --

MR. LEITCH: So an assumption is made for the reaction time of the operators to get there, and that's a -- an assumption that is also based on bad weather conditions, and so forth?

MR. JACOBSON: I'm going to let Rick talk about the corrective actions that have been --

MR. LEITCH: Okay.

MR. JACOBSON: -- taken as a result. But at the time of the inspection, that was not factored in at all, and that was why we had so much concern about that issue is that --

MR. LEITCH: Did you look at the material condition of the Vernon plant? Is that -- was that at all a factor in your inspection?

MR. JACOBSON: We didn't visually inspect the Vernon plant. However, we did look at test procedures and some records associated with its operation, and it -- based on our review of those records, it's been a very reliable operating facility. It pretty much runs all the time.

MEMBER WALLIS: But the man in charge of it is in Wilder, which is quite a long way away.

MR. JACOBSON: We actually visited the Wilder site. That's one thing we did is we took a trip to Wilder and interviewed the operator at the Wilder station that controls that plant. But it does require them to dispatch individuals to the Vernon station. They can't restart --

MEMBER WALLIS: Right.

MR. JACOBSON: -- the Vernon station for a while.

MEMBER WALLIS: I think all of the discussion about whether they can get there in a snowstorm is in the SER. It's not in your inspection report.

MR. JACOBSON: No.

MEMBER WALLIS: Well, at least you've raised the issue.

MR. JACOBSON: Right.

MEMBER WALLIS: Right.

MR. JACOBSON: The second finding involved the adequacy of the procedures used by the Vermont Yankee operators to monitor one of the normal offsite power lines into the station. The procedures did not contain adequate -- contain appropriate acceptance criteria, nor did they reference an appropriate methodology for determining the lowest acceptable offsite voltage for which the offsite power line could still be considered operable.

This was an alternate offsite source that the operators are allowed to credit for tech specs, though our concern was they didn't have adequate guidance to determine whether that offsite source really would be capable of fulfilling its functions under certain conditions.

MR. LEITCH: This is the 115 KV Keene line?

MR. JACOBSON: Yes.

MR. LEITCH: Did you get any sense for whether the operators knew what to do, that this was just a lack of a procedural documentation of the requirements?

MR. JACOBSON: I don't think I can answer that question.

MR. LEITCH: Okay. Okay.

MR. JACOBSON: The third finding concerned the lack of an acceptable degraded voltage analysis. A degraded voltage analysis is performed to ensure that all safety-related equipment can function under the lowest specified voltage for which the offsite or onsite power systems are considered operable.

We did do some rough calculations -- the team did some rough calculations while were onsite just to ensure ourselves that we thought that the calculations would come out favorable once they were done, and we determined that -- we didn't determine any operability questions as a result of the calculations that we did.

MEMBER WALLIS: Do you follow up on this and make sure that the licensee does the calculations?

MR. JACOBSON: Larry is going to talk --

MEMBER WALLIS: He's going to talk about that.

MR. JACOBSON: -- about the follow up.

MR. DOERFLEIN: But the quick answer is, yes, we have.

MR. JACOBSON: Yes. The fourth finding concerned a pressure control valve in the reactor core isolation cooling system, which was improperly installed and not independent of the instrument air system.

The team identified that the loss of the non-safety-related instrument air system would cause this valve to go fully open and would overpressure portions of the reactor core isolation cooling system.

MR. LEITCH: Did you look at the extent of condition there? In other words, were there other -- it sounds like this valve was installed perhaps after the original design. Was there any followup to see whether there was any similar valves that depended on instrument air?

MR. JACOBSON: Yes. That was one of the three findings that we thought could be indicative of a broader concern, so we did review other valves to make sure that they were not dependent on instrument air. And we didn't find any additional examples.

MR. LEITCH: Okay. Thanks.

MR. JACOBSON: The fifth finding concerned Entergy's failure to correct another condition associated with the same pressure control valve. The team identified that this valve was designed to operate automatically but had not operated properly and had required manual operation since its original installation.

So this valve I believe was an original -- part of the original design. They had problems during original testing where it never operated properly and had never corrected the problem for many years.

The sixth finding involved the use of an incorrect and non-conservative input for the condensate storage tank temperature into the plant's transient analysis. Entergy used a value of 90 degrees Fahrenheit when the actual tank temperature could be as high as 120 degrees Fahrenheit.

And this is another one where we looked at extent of condition, because the concern was if they're not using proper assumptions in their accident calculations, it could impact other important calculations such as containment overpressure calculations, and so forth. So --

MEMBER WALLIS: This is where your NPSH was reduced to zero.

MR. JACOBSON: Right. This actually --

MEMBER WALLIS: And then, you decided that was okay.

MR. JACOBSON: Because there's no requirement for margin. Our team did not pass judgment on whether credit should be given for containment overpressure. That was not part of our inspection.

MEMBER WALLIS: Can I ask you about something that you seem to have skipped over? It wasn't the finding. The vacuum breaker system -- vacuum breaker system from reactor building to Torus?

MR. JACOBSON: I believe that was one of

the components that we looked at.

MEMBER WALLIS: That has to work, doesn't it? I mean, it's a leak part, isn't it? It doesn't work?

MR. JACOBSON: I believe so, yes.

MEMBER WALLIS: And how reliable are these vacuum breakers? Don't they sometimes give trouble?

MR. JACOBSON: I can't answer -- the licensee possibly can --

MEMBER WALLIS: But you did inspect that, because it's in your report here.

MR. JACOBSON: Would you like the licensee to answer that, or --

MEMBER WALLIS: You're talking about leaks. What's the assurance that the vacuum breaker will not leak?

CHAIRMAN DENNING: Can the plant address that?

MEMBER WALLIS: Maybe that's something we'll talk about in the future, right? We'll talk about that in the future.

MR. JACOBSON: Go on?

CHAIRMAN DENNING: Go on.

MR. JACOBSON: The seventh finding concerned the plant's safe shutdown analysis, and this is the issue that you asked me to elaborate on. The seventh finding concerned the plant's safe shutdown analysis, which is performed to ensure that the facility can be safely shut down should a fire make the control room uninhabitable.

The team identified that the time it would take for Operations to place the reactor core isolation cooling system into service from the alternate control panel would exceed that contained in the safe shutdown analysis.

In addition, the team identified that Entergy's proposed power uprate would further reduce the time available to perform these steps, and that at the power uprated levels the ability to place the reactor core isolation cooling system into service before the reactor water level reached the top of the active fuel was questionable.

So this is a case where the power uprate reduced the margin -- in other words, reduced the time available to operators to put the reactor core isolation cooling system into place due to increased decay heat that --

MEMBER WALLIS: So how is this handled? Maybe the -- when you're dealing with an EPU where you've got -- the time available is almost exactly the same as the time that it takes them to do the job.

MR. JACOBSON: I think Larry and Rick are going to answer what they've done, but they --

MEMBER WALLIS: It's because --

MR. JACOBSON: -- they've taken corrective actions to --

MEMBER WALLIS: Did they change that time in some way?

MR. JACOBSON: Yes. They've changed the time it actually takes them.

MEMBER WALLIS: So how much margin do you need? If it's estimated to take 21 minutes to do something, presumably that's 21 plus or minus five or something. And if you've only got 21 minutes available, the probability of not doing it would seem to be not -- zero. I mean, quite -- something you have to worry about.

MR. JACOBSON: Well, that's why we were worried about it.

MEMBER WALLIS: So how big a margin do you need in this sort of case?

MR. JACOBSON: Well, I think on any of these cases there is no requirements for a margin in excess of the design basis conditions. And it would apply to this as well as any other calculations.

MEMBER WALLIS: But I can't believe that you can predict how long it takes someone to do something in 21 minutes with great accuracy. It must be quite a span, depending on the athleticism of the people and their smartness and their experience and everything.

MR. JACOBSON: I think when we look at that, we look at their basis for demonstrating what they believe is the time it would take. And, for instance, if they ran five crews through and the time span ranged from 15 to 18 minutes, you know, that would be a factor. In this case, we identified it as a problem.

MEMBER WALLIS: It's not --

MR. JACOBSON: Because it was too close to call, and they've addressed that -- and I think what Rick is going to tell you is they've reduced the timeframe considerably such that they now have a lot of margin. But --

MEMBER WALLIS: So when they did their PRA, did they use the newer vision or the old one?

MR. JACOBSON: I don't believe the PRA looks at margin in terms of --

MEMBER WALLIS: They must look at --

MR. JACOBSON: -- the ability to complete certain functions.

MEMBER WALLIS: It must look at the probability of them being successful. That's the whole -- that's the whole game.

MR. JACOBSON: But it looks at probability of an operator completing an action, but I don't believe it considers how much margin is available.

MEMBER WALLIS: Oh. You mean it says that if he's allowed 21 minutes, and he's got 21.1 minutes, then it's successful? Is that what the PRA says? I mean, how do you decide that it's successful in the PRA? I guess we'll pursue this again some day.

CHAIRMAN DENNING: Yes. Well, we're going to hear a little bit more anyway about what the -- what the -- how it was corrected.

MEMBER WALLIS: Yes. But I think we also need to know what effect it has on the EPU PRA, right?

CHAIRMAN DENNING: Right.

MR. APOSTOLAKIS: Is there going to be a discussion of this later?

CHAIRMAN DENNING: There is a discussion of the finding, but there's not additional discussion of the question that you've raised with regard to PRA.

MR. JACOBSON: Let's continue, because we have very serious findings that --

MEMBER WALLIS: I'm sorry. But, yes, we seem to be raising issues which --

MR. JACOBSON: -- we have to bring --

MEMBER WALLIS: -- might be important, I hope.

CHAIRMAN DENNING: Yes. Absolutely. We have to identify these important issues. I absolutely agree, Graham.

MR. LEITCH: I understand that the root of this problem was that there was some steps added to the procedure. And there was perhaps a failure to communicate between Operations and Engineering as to what those steps were.

I guess, once again, I'm concerned about the generic implications of that. Did you look at any other places? Did you find any other places where there were problems resulting from that lack of communication?

MR. JACOBSON: This was another one of the findings that we looked at from extent of condition concerns, and we didn't find any additional issues. I had the same concern, that if they had added steps to this one, you know, that could be a programmatic problem, where there's a lack of design control with these operator timelines. So --

MR. LEITCH: But you found no other evidence of --

MR. JACOBSON: We found no other examples.

MR. LEITCH: Okay.

CHAIRMAN DENNING: Continue.

MR. JACOBSON: The last -- the eighth finding, the last finding, concerned the acceptability of portions of Entergy's program for testing motor-operated valves. The team identified that in some cases testing was performed without establishing appropriate acceptance criteria, and that in some instances a test methodology was used that had not been properly validated.

There was also an unresolved item identified by the team that concerned the facility's ungrounded 480-volt electrical system, and the potential that a certain type of ground fault could propagate and damage safety-related equipment.

For each of the issues identified by the team, Entergy performed an immediate assessment of its impact on operability. In some cases, they had to do additional calculations. For example, with the RCIC control valve that was overpressurized, they did some extensive work during the inspection to show that that system would hold together even though it was significantly over pressure, and that it wouldn't be an immediate operability concern.

Once entered into the corrective action program, the licensee is required by our procedures, or our regulations and their own procedures, to do an evaluation of both the individual issue and the potential extent of condition and significance of each of the issues. And we actually followed up on each of these issues, and Larry is going to talk a little bit more about that in detail.

I think that's pretty much all I had on the inspection. As I said, Larry is going to -- Larry and Rick are going to talk a little bit more about our followup, and I'll take any additional questions on the inspection approach now, if anyone has them.

CHAIRMAN DENNING: Any questions on that? Okay.

MEMBER SIEBER: Could you give us just a little more detail on the ungrounded 480-volt situation? How did you find it? Why is it ungrounded? Is it a design issue or a grounding connection come -- is missing or something?

MR. JACOBSON: Yes. The ungrounded 480-volt issue -- there's actually other plants that also have ungrounded 480-volt systems. It's an original design consideration, and there is pros and cons of an ungrounded system.

MEMBER SIEBER: Right. It's usually grounded someplace, but not more than one place.

MR. JACOBSON: Well, in this case, it's an ungrounded system.

MEMBER SIEBER: So it is not grounded any place.

MR. JACOBSON: Right. So there's a concern -- there's an actual phenomena that could occur that if you were to get an arcing ground on that system --

MEMBER WALLIS: Right.

MR. JACOBSON: -- that the voltages could essentially accumulate due to the capacitants in the system, such that they would exceed the voltage ratings of the connected motors. We have essentially done an extensive analysis of this issue in NRR after the inspection. Rick is going to talk about how that was closed out.

MEMBER SIEBER: Okay.

MR. JACOBSON: But I believe it has been determined to be acceptable as is. Essentially, you have to weigh the risk of such a ground against the benefits that the ungrounded system provide.

MEMBER SIEBER: It has to be an arcing ground?

MR. JACOBSON: It has to be a certain type of arcing ground that would cause this to occur, which is pretty unlikely.

MEMBER SIEBER: Okay.

CHAIRMAN DENNING: Thank you. Larry, would you go ahead, then?

MR. DOERFLEIN: Sure. As Jeff said, Region I did do inspection followup on all of the findings from the engineering team. We did this as part of our normal baseline process, so they were scattered throughout the year. For instance, we looked at one of the issues during one of our routine baseline inspections. We didn't -- we just didn't send another team to go follow up on all this stuff.

Our inspection followup consisted of verification that Entergy took appropriate corrective actions to address the deficiency and performed an extent of condition review. In March, we completed the followup inspection for the RCIC startup timeline issue and the procedure for assessing operability of offsite power.

Regarding RCIC, we found that Entergy made appropriate procedure revisions and conducted training to correct the problem. In addition, we found that their extent of condition review was comprehensive.

I would like to add that our followup inspection included a procedure walkdown with the operators and verified the system could be started in about 14 minutes.

If you're interested in the specific issue, steps had been added to the procedure, but they were safety steps, OSHA-required safety steps -- don face masks, don aprons, don gloves -- things that probably were added that nobody gave a thought to until -- it just makes the procedure take longer.

MEMBER WALLIS: Yes. When the reactors are -- the reactors are at risk, you don't want to fiddle around with a lot of detailed --

MR. DOERFLEIN: Well, not only that, but, as I understand it, the OSHA requirements were for open cabinets. Some of these -- some of these were just pushing buttons on closed cabinets. So they revised the procedure to -- they still passed it through their Safety Committee obviously, but a revised procedure to take out the extra steps.

Plus another contributing cause, I think, was all of these things are practiced in the requal program. Some are done in classroom, some are done in the field. This happened to be done in the classroom, so a little familiarity issue. But once they fixed the procedure and trained the operators, it -- they could get it done in 14 minutes.

Regarding the offsite power issue, that was -- this is the procedures. That was a pretty narrow issue. We found that Entergy made adequate procedure revisions and trained the operators on the changes. The inspection results for both of those issues are documented in Inspection 2005-02.

In August, we completed the followup inspection for the degraded relay setpoint calculations and the storage temperature issues. For the degraded relay setpoint issue we found that Entergy had appropriately revised their electrical calculations and determined that the safety-related equipment would remain operable with a minimum voltage of 3,660 volts AC at safety buses 3 and 4.

Regarding the CST temperature issue, we found that Entergy had completed an appropriate extent of condition, which considered present power conditions in those that would exist at the proposed uprate, and identified about a dozen calculations that use non-conservative temperature values.

In fact, we identified two additional

examples, one of which Entergy identified but had dropped through an administrative error, and one -- it didn't involve a max temperature. It actually involved a minimum temperature. But that was on a valve torque calculation. So all of those extra examples really had negligible impact.

The inspection results for those issues are documented in Inspection Report 2005-04.

In September, we completed the inspection followup for the availability of power from Vernon station, and the motor-operated valve testing issues. For the Vernon station issue, as we already mentioned, Entergy completed and submitted a two-hour coping analysis to the NRC. They revised their station procedures to prioritize getting the hydroelectric station back, and they established protocols with the grid operator.

Regarding the MOV issue, Entergy appropriately revised their program for training and evaluating MOV performance. And they also made provisions to provide for validation of the motor control center test method. That validation program includes periodic reverification of the test method over an extended interval.

The inspection results for both of those issues are documented in Inspection Report 2005-06.

Subsequent to that inspection, we also observed the table-top exercise with the grid operator with simulated at grid collapse and restoration, and determined that power could be restored to Vermont Yankee within two hours. That's very conservative. We actually think it's going to be much less than that.

It depends on how fast they can get the hydro station back, actually. That's -- once the hydro station is back, they will have power, and we think that can be done in 90 minutes, but certainly within the two-hour coping analysis.

The results of those observations will be documented in the next resident inspector quarterly inspection report.

As also documented in Inspection Report 2005-06, two of the findings will require additional followup inspection. The corrective action for both involve replacing the RCIC lube valve core pressure control valve. Entergy had intended to replace the valve during a recent outage. However, the unexpected complexity of modification and delays in obtaining parts caused that schedule to slip.

When we inspected the issue in September, the valves were scheduled to arrive after the outage, and the modification package had not been completed. Entergy currently plans to implement the mod during the week of December 12, 2005.

While we did find Entergy's evaluation of the problem and extent of condition to be adequate, we intend to perform additional inspection and modification including the post-modification testing and the 50.59 evaluation as part of our baseline program.

There was also one unresolved item identified during the engineering team inspection regarding the adequacy of the 480-volt ungrounded system as already mentioned. NRR has recently completed a review of that issue under a task interface agreement with Region I.

The conclusion was that the current design meets the licensing basis, and that the issue is not risk-significant because of the low likelihood for failure of redundant or independent safety systems due to a failure to non-safety loads.

The result of that review will be documented in the next quarterly resident inspection report. And that concludes my followup of the inspection issues.

MR. LEITCH: Just slightly off the topic, but do you happen to know, Larry, the licensee's current status with respect to the reactor oversight? Are all of their performance indicators green?

MR. DOERFLEIN: As far as I know, all of the performance indicators are green.

MR. LEITCH: And do you know if there are any --

MR. DOERFLEIN: And they're in the regulatory -- or the licensee response column. So the inspection findings --

MR. LEITCH: So the licensee is responsible. Yes, okay. And are there any -- are there any inspection findings greater than green that are open at the moment that you're aware of?

MR. DOERFLEIN: I'll have to get back to you on that.

MR. LEITCH: Perhaps it's not a fair question. I'm not -- I know it's not on the agenda.

MR. DOERFLEIN: The only reason I hesitate is there may be one EPU issue on phone alert radios that I don't have the answer to.

She's the resident inspector. She's telling me that issue is closed, so there are no greater than green items open.

MR. LEITCH: Okay. Thank you.

CHAIRMAN DENNING: Okay. Can Rick finish in 15 minutes? Is that reasonable, or is that too -- okay. Let's go ahead and finish that up, then, before we go to lunch.

MR. ENNIS: Thank you. My name is Rick Ennis. I'm the Project Manager for Vermont Yankee in the NRC's office of NRR. I'll now discuss the impact the engineering inspection had on the EPU amendment review.

Shortly after the completion of the inspection, Jeff Jacobson and several members of the inspection team held discussions with the NRR staff that were reviewing the EPU amendment. And based on those discussions, as well as the technical areas that are covered in the review standard RS-001, as well as the information that has been submitted on the docket by Entergy to support the EPU amendment, we determined that four of the inspection findings impacted the EPU review.

The other four findings were determined to not relate specifically to the changes being proposed for the EPU.

Specifically, the findings that impacted the review were the issues related to station blackout, the timeline for operator action to place the reactor core isolation cooling system in service following Appendix R fire, periodic testing of the motor-operated valves, and condensate storage tank temperature.

The NRC staff held several conference calls with Entergy to discuss the issues from the engineering inspection. And the purpose of those calls was to ensure that Entergy's proposed corrective actions would include supplements to the EPU application to address the relevant findings.

Entergy subsequently submitted various supplements to address the findings. In some cases, the NRC staff issued requests for additional information, and further supplements were submitted by Entergy to fully address the issues. And now I'll discuss each of the issues.

With respect to the finding related to the Vernon hydrostation and station blackout, the EPU review standard RS-001, Safety Evaluation Section 2.3.5, station blackout, requires that the NRC staff reach the conclusion that the licensee has adequately evaluated the effects of the proposed EPU on station blackout, and demonstrate the plant will continue to meet the requirements in 10 CFR 50.63 following implementation of the EPU.

The engineering inspection team found that in the event of a regional grid collapse, the Vernon hydrostation, which is the Vermont Yankee alternate AC source, would trip offline and have to be restarted. For station blackout scenarios where the licensee cannot demonstrate by test that the alternate AC source would be available in 10 minutes, 10 CFR 50.63 requires the licensee to complete a coping analysis for the period of time it would take for the power to be restored.

Prior to the inspection, the licensee had credited the Vernon hydrostation as being available within 10 minutes. As such, the licensee had not performed a coping analysis. As a result of the issues raised during the inspection concerning mostly the communications and actions required to restart the hydrostation, the licensee created a preliminary timeline which estimated the time to restore power following a grid collapse could be somewhere between 20 minutes and two hours.

Since it was determined that the Vernon hydrostation could not be made available in 10 minutes, as was the previous assumption, the licensee performed a coping analysis which was submitted in

Supplement 25 to the EPU application dated March 24, 2005.

The coping analysis which the licensee performed assuming EPU conditions was based on a two-hour coping requirement, and that coping requirement means that the -- the period of time the hydrostation is assumed unavailable.

As discussed in Section 2.3.5 of the safety evaluation, the staff's draft safety evaluation, the licensee's coping analysis used the guidance in Reg. Guide 1.155 and NUMARK Standard 87-00.

The licensee -- the NRC staff's review of the coping analysis found that during this two-hour coping period there would be adequate condensate inventory to maintain core cooling. Class 1E batteries have adequate capacity to supply all required loads. Equipment operability will be maintained at the elevated room temperatures caused by a loss of ventilation.

Containment isolation capability will be maintained as required to ensure containment integrity, and the resulting Torus temperature satisfies the net positive suction head requirements of the residual heat removal and core spray pumps without the need for crediting containment accident pressure.

Based on these findings, the staff concluded that Vermont Yankee will meet the station blackout requirements in 10 CFR 50.63 under EPU conditions.

With respect to the finding related to the Appendix R timeline for initiation of the reactor core isolation cooling system, RCIC, EPU review standard RS-001, safety evaluation section 2.11, human performance, requires the staff to conclude that the licensee has appropriately accounted for the effects of the proposed EPU on the available time for operator actions.

The inspection team found that the timeline for operator actions to place the RCIC system in service from the alternate shutdown panels during an Appendix R scenario have been impacted due to procedure changes, and the licensee had not incorporated these changes into the Vermont Yankee safe shutdown capability analysis.

MR. APOSTOLAKIS: Now, let me understand something here. Why didn't -- I mean, I read the SER, which was -- which includes this discussion. But why did it take a special inspection to figure it out?

Couldn't the reviewers have identified this as an issue without an inspection?

MR. ENNIS: I don't --

MR. APOSTOLAKIS: It seems to me that from the evaluation the staff relies too much on what the licensee has proposed. Why did it take an inspection to figure it out, that the time was close to the time to core uncovery? I mean, what is special about the inspection?

How did you guys figure it out and the reviewers perhaps had not figured it out? Do they have any guidance what things to look for in EPUs, and which one of them would be the initiation of RCIC under a fire scenario? It's a mystery to me how that happens.

And I don't know if it's relevant here, but also there is a repetitive statement here that there are small reductions in time available for some operator actions, and then the licensee used the -- an industry standard technique to figure out that the response times were sufficient. And I'm wondering whether the NRC staff has actually reviewed these industry standard techniques.

Are they a black box, and we are accepting the results of these? Or has the staff actually reviewed those? Is that an EPRI methodology?

MR. ENNIS: Let me address the -- you know, typically, when you're reviewing a license amendment request, you're reviewing changes to the licensing basis. So typically what the staff gets submitted is the results of the licensee's analyses and calculations.

Typically, we don't even get all of the calculations, unless there is some issue that we think needs further followup, and then we may request further information, that they submit the calculations.

In this case, as part of their power uprate safety analysis report, the PUSAR, there was a table in there that included the differences for EPU between the time to core uncovery. So on the current power level, they had assumed it was going to take 25.3 minutes, and then under EPU they said it would take 21.3 minutes.

So, you know, from a licensing standpoint, the information we have at that point is that there was a reduction of about four minutes to the EPU, and other past licensing basis information that we have, we'd go back and look at the fire safe shutdown analysis, and the assumptions in there, the assumptions would be that those actions could be completed within 15 minutes. That was the 1999 analysis.

So based on that, taken alone, you know, it would appear to you that you have six minutes of margin. Okay? For EPU conditions.

MR. APOSTOLAKIS: For EPU conditions? No, that was 1999. Was it done under EPU?

MR. ENNIS: No. The safe shutdown analysis -- the Appendix R analysis assumed it was --

MR. APOSTOLAKIS: That was under the --

MR. ENNIS: -- on the licensing basis. So they had 10 minutes of margin previously, and then it was reduced. This was before the finding, okay? This is when -

MR. APOSTOLAKIS: Well, that's my question. Why did you find this and not the reviewer?

MR. ENNIS: Because, well, the issue had to do with the changes to procedure, which is covered under 50.59. So we -- you know, there's changes a licensee can make without prior approval of the NRC staff. So they typically change procedures, change calculations. It does not require NRC review and approval.

MR. APOSTOLAKIS: No. But the time to

place RCIC in service, is that a 50.59 thing? I mean, that's an observation, is it not? That's not a 50.59 issue.

MR. ENNIS: I'll try -- I understand your question, and I think what we've learned during this whole experience was that the inspection complemented the review --

MR. APOSTOLAKIS: Right.

MR. ENNIS: -- and found this. It would be doubtful that a reviewer could find this.

MR. APOSTOLAKIS: Why not?

MR. DOERFLEIN: Because they don't go to the site and --

MR. APOSTOLAKIS: Well, what did you do? Did you actually walk there and see how much time it takes, or --

MR. DOERFLEIN: Yes. We actually -- we actually walked through it and saw that -- what it took, the 19 minutes or whatever. We did do that. That was part of the inspection. And I think it was -- like I said, I think it complemented the review, the EPU amendment review.

And the Commission paper, at least the last version I saw, recommended that more of this inspection interaction take place in further EPU --

MR. APOSTOLAKIS: So what happens at other plants that didn't have the benefit of such an inspection? I mean, typically what we see in the ACRS is that the licensee argued that the reduction in time was not significant, and usually the staff agrees.

I mean, shouldn't there be some guidance as to what they should look for? I mean, does the staff have this guidance, that maybe this issue now or in the future will become something that will be standard and people will focus on it?

MR. JACOBSON: The point you're raising I think is a fundamental question, which is, you know, what do we look at when we do licensing procedures, and what do we look at when we do inspections?

And I think what we found in this case is that there are certain things that are looked at during inspections that aren't typically looked at in licensing reviews, and there needs to be a better integration of those two activities, not just for EPUs but for any significant risk-important license information that the NRC is approving. And we have it as a commitment to go back and look at our licensing process and figure out how we can better integrate activities such as this in the future.

So we recognize the point that you're

raising, that there is a vulnerability there, and that we need to better look at the types of things that are done during a license review and the types of things that are done during an inspection.

MR. APOSTOLAKIS: We have approved, as we saw earlier on a table, 607 such EPUs already. Do we go back now and check whether --

MR. JACOBSON: Well, I think the other thing you need to consider is that in the past these other licensees have gotten inspections, too. They just weren't called out as power uprate engineering. They all are subject to our routine engineering inspections that look at this type of issue as well.

MR. APOSTOLAKIS: Yes. But, I mean, as you show here, in 1999 it was okay. So those inspections, you know, if they are not related to an EPU, they would not look for it. I mean, they will find it's okay. So now that we have approved EPUs for several plants, and we were not aware of the issue, I don't know what do we do. Do we go back? Can we do that?

Now, in the future I hope there will be some guidance to the reviewer that this may be an issue. The issue of human performance has been a sore point with me.

MR. THADANI: Yes. George, let me --

MR. APOSTOLAKIS: Because I think the reviewers tend to accept what the licensee says.

MR. ENNIS: It's an integrated approach. I mean, you have an inspection approach, and you've got the reviews that are done on changes to the licensing basis. You can't -- you know, you have to rely on --

MR. APOSTOLAKIS: If you had done -- let me ask you this question. If Vermont had not insisted on a special review, and you had done your standard 475-hour inspection, would you have found this?

MR. ENNIS: I don't know. I can't answer that. I don't know. It depends on what scope of the item they looked at. And maybe it would have been found through routine inspection by the resident inspector. Maybe it would have been found through some other -- through an Appendix R inspection that was I think scheduled. When was that going to -- it was a month after that.

So there are opportunities to find these in different types of inspections that are done. And we don't review every single calculation change that a licensee makes as part of an amendment review. We're assuming that the 50.59 process works, and we verify that through the inspection process.

MR. APOSTOLAKIS: I still don't understand what 50.59 has anything to do with this. It has nothing to do with this. This was an observation.

MR. ENNIS: No, it's --

MR. APOSTOLAKIS: Why not?

MR. ENNIS: Because there are procedure changes that are made under the 50.59 process, and those procedure changes didn't adequately account for their licensing basis.

MEMBER WALLIS: Well, I have another question here, which is sort of related. Is the 21 minutes that's reported here an inspection team finding? What did the licensee say it was when they were comparing it with 21.3? You thought it was 21 minutes. What did they think it was?

MR. APOSTOLAKIS: They probably assumed it was a very small change from the 15 minutes that --

MEMBER WALLIS: Therefore, they didn't bother to make any calculation at all? Is that what happened?

MR. APOSTOLAKIS: I don't know.

MR. ENNIS: Their assumption was --

MEMBER WALLIS: Is it still 15 minutes?

MR. ENNIS: Fifteen minutes.

MEMBER WALLIS: Ah. So they claimed it was still 15 minutes.

MR. ENNIS: Right.

MR. THADANI: The issue, it seems to me, is actually broader, because not only for this Appendix R sequence, for station blackout, for ATWS, various scenarios, there is going to be less time available to the operators to take appropriate actions, because of extended POP.

Is that systematically looked at? At least in terms of risk analysis? I mean, looking at core damage frequency and large early release frequency, is that looked at systematically to see what the human contribution is to risk in terms of changes, because of the large uncertainties that --

MR. APOSTOLAKIS: That's why I wanted some guidance, specific guidance on --

MR. THADANI: It needs to be more systematic, it seems to me, not just one scenario.

MEMBER WALLIS: Right.

MR. APOSTOLAKIS: And I don't know, are we going to discuss 2.11 with the reviewers later, or -- because, again, I find this thing that always bothers me. I mean, the industry has done something. We have not really reviewed it, but it's okay. The results are okay.

MR. ENNIS: Section 2.11 --

MR. APOSTOLAKIS: Yes, that's not your responsibility.

MR. ENNIS: Okay. I was saying Section 2.11 will be discussed as part of the meetings on the 29th and 30th, the overall review of human performance.

MR. APOSTOLAKIS: Okay.

CHAIRMAN DENNING: Rick, I think we can move on.

MR. ENNIS: Okay. So, you know, to summarize, at the current power level, the safe shutdown capability analysis that was performed in '99 determined it would take 25.3 minutes for the reactor water level to reach the top of active fuel following a loss of feedwater, and it would take 15 minutes to place the RCIC service from the open and shutdown panels.

Therefore, at current power conditions, the analysis concluded that there was adequate margin -- about 10 minutes -- to ensure that RCIS was placed in service and keep the core covered. As I mentioned as -- for EPU conditions, as shown in the PUSAR -- and that's in Table 6-5 -- the licensee determined the time to core uncovery would be reduced from the 25.3 minutes to 21.3 minutes. They reduced it by four minutes.

The engineering team found that the 15-minute timeframe to place RCIC in service as documented in the safe shutdown capability analysis was actually closer to 21 minutes based on the procedure that was in effect at that time.

Therefore, the team concluded there was about four minutes' margin at current operating conditions, but virtually no margin at the proposed EPU conditions. As the corrective action to the NRC's inspection finding, the licensee revised the procedure, as Jeff mentioned, governing the required operator actions, completed training of the Vermont Yankee license operators on the revised procedure, and they performed timed walkthroughs of the actions required in the procedure with all six operating crews.

The results of the walkthroughs was documented in the licensee's Supplement 22 dated December 8, 2004, and the operating crew times ranged from slightly over 12 minutes to about 15 minutes, with the average time being about 13-1/2 minutes.

Based on this information, the NRC staff concluded that sufficient margin exists of six minutes to place to RCIC in service during an Appendix R event at EPU conditions.

MR. APOSTOLAKIS: I wonder how reliable these 13-1/2 minutes are. I mean, there were not really times on the real accident conditions, were they?

MR. ENNIS: Well, it was a walkthrough of actual procedure, though.

CHAIRMAN DENNING: Is this done on the simulator? I mean, is all of this occurring within the control room? And it's done in the simulator?

MR. ENNIS: You have to go to the aux shutdown panel.

CHAIRMAN DENNING: So you have to walk through the plant.

MR. ENNIS: Yes.

MEMBER WALLIS: Well, that's the whole question is what's sufficient margin? I mean, you look at this thing, and you use a judgment that if it takes 21 minutes and we've got 15 it's okay. Is this a judgment call?

MR. ENNIS: Yes.

MEMBER WALLIS: How do you know when to say, no, it's not enough? Do you --

MR. APOSTOLAKIS: When it's 21 and the available is 21.3.

MEMBER WALLIS: No, that's not -- this doesn't seem a very convincing answer, then. Besides, I didn't ask you, George. I --

(Laughter.)

But I think you need to -- these human actions, how you decide sufficient margin exists? You need to explain that.

MR. APOSTOLAKIS: If you look at all the models that people have developed for human error probabilities, time is just one of the inputs. Here we are placing our whole argument on their time. I mean, I don't know how they will react when they actually have it higher, and they have to go to this alternate shutdown path. I mean, there are so many other things that are important.

But ultimately, you are right. It's just a judgment. Ten minutes is good enough now.

CHAIRMAN DENNING: Go ahead, Rick.

MR. ENNIS: I'll move on, briefly talk about the periodic testing of the MOV's findings. EPU review standard RS-001, safety evaluation section 2.2.4, safety-related valves and pumps requires the NRC staff to reach the conclusion that the licensee has adequately evaluated the effects of the proposed EPU on its motor-operated valve programs related to Generic Letters 89-10, 96-05, and 95-07, and the lessons learned from those programs to other safety-related power-operated valves.

The inspection team found that the licensee did not manage NRC commitments and conditions documented in the safety evaluation for Generic Letter 96-05 MOV periodic verification program.

Specifically, in a safety evaluation dated December 14, 2000, the NRC provided its basis for accepting Vermont Yankee's response to Generic Letter 96-05, periodic verification of design basis capability of safety-related power-operated valves.

The safety evaluation documented the licensee's intentions to use motor -- current data required from the motor control centers, MCCs, as a way of detecting actuator and valve degradation. Safety evaluation also documented the licensee's intention to verify this testing methodology by comparing the data with direct torque and thrust measurements at the valve over extended intervals.

In addition, the safety evaluation stated that the licensee would have to determine MCC test instrumentation accuracies and sensitivities to MOV degradation, as well as evaluate changes in MCC data and MOV thrust and torque performance.

During the inspection, the team concluded the licensee had not validated the adequacy of the MOV test instrumentation to assure its adequacy and to establish test procedures with adequate acceptance criteria tied to stem thrust to our available design margin.

Additionally, the team found that MOV diagnostic testing had been conducted solely from the MCCs. The team did not identify any examples of degraded or inoperable valves during inspection. As part of the corrective actions, the licensee, in Supplement 16, dated September 30, 2004, committed to revise the MOV periodic verification program to include periodic at-the-valve testing and to formalize the process for DC motor trending by December 1, 2004.

In Supplement 32, dated September 10, 2005, the licensee stated this commitment is complete. The staff's draft safety evaluation concluded the licensee has demonstrated that the safety-related valves and pumps will continue to meet the applicable requirements following implementation of the EPU.

MEMBER SIEBER: I take it that Vermont Yankee doesn't use diagnostic equipment like MOVATS or any of those?

MR. DOERFLEIN: The answer to your question is, right, they weren't using --

MEMBER SIEBER: Diagnostic equipment.

MR. DOERFLEIN: -- diagnostic -- but they have changed, and they are validating with at-the-valve equipment and comparing it with the MCCs now. That's the program they're starting to validate now.

MEMBER SIEBER: Okay.

MR. DOERFLEIN: But their goal is just to use the MCC testing.

MR. JACOBSON: Let me expand. They were using that type of equipment. The problem was they were using experimental versions of that equipment. This testing of motor current from the MCC, and then drawing analogies with regard to valve thrust and torque, was an experimental type of application that hadn't been properly validated.

So they actually were cutting edge, but hadn't properly validated what they were doing.

MEMBER SIEBER: Yes. But this -- the issue has been there for years, and the equipment has been there for years. And it's not clear to me, unless they don't want to buy the equipment, why they're trying to develop something new when they could just do what everybody else does.

MR. JACOBSON: Well, because it's less intrusive if you do it from the MCC -- it's at time-saving thing. See, that's the impetus to do it that way.

MEMBER SIEBER: You don't get the information either, all of the information that's helpful -- let me put it that way. You get the essential information.

MR. ENNIS: With respect to the finding related to the condensate storage tank temperature, EPU review standard RS-001 safety evaluation, Section 2.6.5, containment heat removal, requires the NRC staff to review the containment heat removal system's assessment provided by the licensee and concluded that the licensee has adequately addressed the effects of the proposed EPU.

This review includes the effects of the proposed EPU on the analysis of available net positive suction head, NPSH. The engineering inspection team found that the licensee used non-conservative condensate storage tank -- CSC temperatures and calculations for current plant conditions, as well as for EPU analyses.

As a result of this finding, the licensee, in Supplement 18 dated October 5, 2004, revised the ATWS analysis to take into account the higher suppression pool temperature resulting from the assumed change in condensate storage tank temperature.

The licensee estimated that this change in condensate storage tank temperature results in a 0.5 degree increase in the suppression pool temperature from 190 up to 190.5.

The staff's safety evaluation concluded that the effects of this change is acceptable, since the peak suppression pool temperature as a result of the ATWS event was previously calculated to be 190, and the peak suppression pool temperature for the limiting event is actually the LOCA. And that temperature is 194.7.

Therefore, the staff concluded the effect of the change in CFT temperature was acceptable, since the limiting suppression pool temperature would not be exceeded.

MEMBER WALLIS: And this is the temperature we saw earlier today, which requires NPSH.

MR. ENNIS: Yes. I think it was 195.

MEMBER WALLIS: This is some other structural limit or something rather than NPSH on temperature? Is there some other limit on temperature, other than NPSH? There is, isn't there?

MEMBER SIEBER: Well, the higher the temperature, the higher containment pressure. And ultimately you get to a structural limit on containment. That's a long ways away.

MEMBER WALLIS: There's some limit on the air space temperature for structural reasons, isn't there? Well, maybe we'll look at that some other time, but that's also in the SER. I need to connect the two somehow.

MR. ENNIS: In conclusion, for all four findings that the NRC staff determined impact of --

MEMBER WALLIS: Excuse me. When you said the limiting temperature will not be exceeded, do you mean there's some other temperature which is bigger that -- in a different event; therefore, we don't need to worry about this.

MR. ENNIS: Right.

MEMBER WALLIS: It's not some sort of limiting criteria.

MR. ENNIS: No. No.

MEMBER WALLIS: Okay.

MR. ENNIS: The LOCA event is the limiting event.

MEMBER WALLIS: Okay.

MR. ENNIS: In conclusion, for all four findings the NRC staff determined the impact of the EPU review, the licensee submitted supplements to the application to address the findings. The staff has reviewed this information and concluded that the issues have been adequately addressed for the proposed EPU.

I also wanted to just briefly summarize the whole engineering inspection effort. We believe the inspection was responsive to the Vermont Public Service Board request for an independent assessment in terms of the hours spent, the scopes of the inspection, and the independence of the team.

MEMBER WALLIS: It's not just the scope. I think it's also the focus, that you focused on certain things which were important. It's not just the scope itself, but --

MR. ENNIS: Correct. We also considered that the pilot approach, inspection approach, is an improvement over the vertical slice inspection approach.

All of the inspection findings were of low safety significance and were not indicative of any programmatic concerns. All of the inspection findings have received followup inspection by the NRC for the licensee's corrective actions, and the four findings that impacted the review have been adequately resolved as addressed in the staff safety evaluation.

MEMBER WALLIS: Well, they have low safety significance, unless the way in which they treat operator actions is sort of generic across the whole -- I know it's universal across the whole plant. I mean, maybe there is a problem with operator actions going beyond this particular one. I don't know. I haven't -- did you follow up to say, "Well, look, these operator actions were not treated very well, how about other ones"?

MR. JACOBSON: That was one of the issues that we did look at extent of conditions to see if there were other operator actions that were problematic, and we didn't find any that --

MEMBER WALLIS: Didn't find any.

MEMBER SIEBER: Good.

MEMBER RANSOM: Is there a measure of defense in depth for some of these operator actions that have to occur in, you know, certain time periods? You know, if it's -- if they fail, does it result in core damage?

MR. JACOBSON: I think it would depend on the scenario as to whether core damage would occur and what other assumptions you would assume in that sequence.

MR. APOSTOLAKIS: Well, you do conclude that all of your inspection findings were of low safety significance, right? So you didn't think that --

MR. JACOBSON: Well, that's based on the fact that ultimately, for instance, this operation action is now it could be done. If it couldn't be done, then you would have to do a --

MR. APOSTOLAKIS: So the inspection findings themselves were not of low safety significance. As a result of what happened after the inspection findings, now we don't have a problem with it.

CHAIRMAN DENNING: Well, I don't think that's the proper -- what he's saying.

MR. JACOBSON: Well, even for that one, you have to look at it for the conditions that existed at the time. They still had adequate margin, even with the problem with the procedure, so they could have performed their actions if that event had occurred at any time prior. That's how we assess risk.

MEMBER WALLIS: Well, it's sort of iffy,

isn't it, because we don't know how fast the level is going down. Maybe if they took 23 seconds -- minutes, the core would only be uncovered so little that nothing much would have happened. We don't really know the consequences of not quite doing it on time, do we? It isn't a question that the core instantly is destroyed when you take .1 minutes longer.

MR. JACOBSON: Well, that was to begin core uncovery. Correct.

CHAIRMAN DENNING: And exactly what do we mean by "core uncovery" here, too? There's another question -- are we talking collapsed level, or what are we talking?

MR. APOSTOLAKIS: Yes, yes, yes, yes.

MR. JACOBSON: I don't know off hand.

MEMBER WALLIS: So it doesn't mean much to me until you've coupled the thermal hydraulics with the PRA in a rational way.

MEMBER KRESS: It's not hard to calculate. You're just boiling down the water in --

MEMBER WALLIS: All right. I understand that. But how about the consequence of it not being quite right? What's the consequence of uncovering an inch of the core? Probably nothing.

MEMBER KRESS: It depends on your

definition of what is --

MEMBER WALLIS: It doesn't depend on my definition. It depends on how --

CHAIRMAN DENNING: Well, clearly, there are some items that we've -- issues that we've identified here that are a little bit more generic than just Vermont Yankee that we have to discuss. Anybody want to discuss anything more on this inspection, because it is getting close to lunch, isn't it? And now we have --

MR. APOSTOLAKIS: I have a question.

CHAIRMAN DENNING: What's that?

MR. APOSTOLAKIS: I have a question, Mr. Chairman, of the committee. Can we have, in the future, all of the presentations be made by Mr. Doerflein? He doesn't use more than two slides.

(Laughter.)

All of them.

CHAIRMAN DENNING: I believe that that was a rhetorical question.

The bad news is that we are only going to have half an hour for lunch. So please be back here at 1:30.

Thank you. Good-bye.

(Whereupon, at 12:57 p.m., the

proceedings in the foregoing matter went off the record for a lunch break.)

CHAIRMAN DENNING: It's clear that we're going to be late getting to the public comments. How late isn't totally clear at the moment. We're going to do our best to get there as quickly as possible. But I think for you members of the public that have heard -- been with us this morning recognize that it really is critically important the Advisory Committee critically review the presentations that are being mae to us. And I hope that you will understand that.

Please, would you continue where you left off?

MR. LOBEL: Okay. Again, this is Richard Lobel. I am a Senior Reactor Systems Engineer with the Office of Nuclear Reactor Regulation.

I think I was talking about required NPSH and the Reg. Guide position, and maybe I can just summarize to take some time -- to save some time.

The licensee didn't exactly follow the guidance in the Reg. Guide, which is to perform --

MEMBER WALLIS: Rich, could you move a little bit this way? You're blocking the screen.

MR. LOBEL: The licensee didn't exactly follow the guidance in the Regulatory Guide 1.82, Revision 3, about required NPSH below head reduction of three percent, where it says that pump tests should be performed for the amount of time the pump is going to be in cavitation, and then a post-test examination should be done.

The licensee used some data from their own pumps -- I shouldn't say the licensee, but the licensee asked the pump vendor to evaluate the time at reduced required NPSH, and the pump vendor evaluated data from Vermont Yankee pumps, from pumps similar to Vermont Yankee pumps, and then used essentially engineering judgment for the amount of time these pumps could operate -- the Vermont Yankee pumps could operate at these reduced required NPSH values.

The similar pumps were pumps that the pump vendor picked based on the fact that the NPSH requirements of the pumps were identical to Vermont Yankee pumps. In other words, they had the same specific speeds, suction-specific speed, blade inlet angle parameters in the pump that affect NPSH.

On the basis of the pump vendor's expert judgment, the testing that was done, and experience of the staff with testing of pumps under similar circumstances, we accepted the use of the licensee's reduced required NPSH values.

Let me go on to conservatism, because there's a couple of points I'd like to make in Slide 5-12. The licensee stated that the conservative initial conditions assumed in the design basis calculations are responsible for the need to rely on containment accident pressure.

And the staff, after looking at licensee calculations and sensitivities, agrees with this statement, but even more it's not limited to just initial conditions. There are many other assumptions in the calculation that are conservative.

And no one is saying that conservatism should be removed from these calculations. There are uncertainties in these calculations that have to be accounted for, but it is worthwhile to appreciate why the licensee is in the situation of crediting containment accident pressure.

Also, as we have discussed with the ACRS in another context, we think there are ways of treating the conservatism, which give a more realistic but still conservative result.

I'm going to -- I enclosed a list of some of the conservatisms that are included in the analysis, and I didn't mean to ever go through all of these. I just put them in for interest. They would take a lot of time to explain.

So let me go to 5-17 -- page 5-17, and just say a final observation on conservatism is that a large factor in making these calculations so conservative is that all of these conservatisms are applied simultaneously.

MEMBER WALLIS: Rich, can I ask you something about that? They assume that none of the paint chips get to the strainer. Is that a conservative way to look at it? I would think the conservative thing to do would be to put them all on the strainer, if you do nothing else.

MR. LOBEL: Their decision not to include paint chips was based on experiments that they did where they set up a screen and -- and a pump flow similar to the Vermont Yankee pump flow, and the decision -- the conclusion that they didn't need to include paint chips was based on the fact that because of the large area of the suction screens at the flow rates they were using, and the specific gravity of the paint chips, the paint chips weren't reaching the sump screen.

MEMBER WALLIS: This is assuming there's no chemical reaction or anything that's putting bubbles on the paint chips and making --

MR. LOBEL: Well, this is -- yes, this is a BWR, and there's no boron. It's --

MEMBER WALLIS: No boron. There's no --

MR. LOBEL: It's pure water.

MEMBER WALLIS: It's only pure water; there's nothing else in it?

MR. LOBEL: I'm not sure for Vermont Yankee. Some BWRs operate with hydrogen gas for stress corrosion and cracking.

MEMBER WALLIS: That won't come out on the --

MR. LOBEL: But no other --

MEMBER WALLIS: There's no dissolved gas which will come out on the paint chips and sort of make them buoyant and in some way --

MR. LOBEL: And do what?

MEMBER WALLIS: Dissolved gas come out on the paint chips as the -- as the pool heats up, dissolved gases come out of solution, and they tend to come out on particles.

MR. LOBEL: Right.

MEMBER WALLIS: I just --

MR. LOBEL: Well, these tests weren't done at temperature, I don't believe.

MEMBER WALLIS: Okay.

MR. BANERJEE: Was the insulation such that it can't form particles? No, no, just the insulation.

MR. LOBEL: I don't remember the details and what kinds of materials they used, but they used materials typical of Vermont Yankee, and --

MR. BANERJEE: Which is what?

MR. LOBEL: I don't remember off hand.

MR. BANERJEE: Are they particles or fibers or --

MR. LOBEL: In the interest of time now, I said that I would get you the documents or the licensee will supply the documents to you. And if we need to discuss this after you've looked at the documents, could we do it at another meeting?

MR. BANERJEE: Right.

MR. LOBEL: Because I really don't remember all of the details to give you much more information.

MR. BANERJEE: Well, until we do, it's not necessarily a conservatism.

MR. LOBEL: No, I'm not saying it's a conservatism. And I didn't list it as a conservatism in the conservatism --

MR. BANERJEE: I thought it was.

MEMBER WALLIS: On Slide 15 -- slide 15 it says value of ECCS strainer head loss used is greater than predicted. And we're saying, "Well, how about the assumptions that went into that prediction?"

But I think that you're right. We'll come back to it some day. We'll come back to it --

MR. LOBEL: Of the debris that does go to the screens, this conservatism applies.

Okay. So not only are there a lot of individual conservatisms, but the conservatisms are applied simultaneously. Vermont Yankee is assumed to be operating at its maximum power with the quantities controlled by tech specs, technical specifications, at their limiting values, with all phenomena such as break flow, decay heat, heat transfer, occurring in the most limiting way, and other quantities such as pump flows and heat exchanger effectiveness at their most limiting values, all at the same time.

5-18. One of the -- one of the conservatisms -- and we talked about this a little before -- is the assumption of the worst single failure, which for this case is failure of the RHR heat exchanger outlet valve to open, which results in only one RHR heat exchanger being available to cool the suppression pool.

With the single failure, the suppression pool temperature following a large break LOCA is 194.7 degrees Fahrenheit, and credit for containment accident pressure is needed. Without assuming a single failure, with all other conservative assumptions still included, the suppression pool temperature is 169 degrees, and credit for containment accident pressure isn't needed, and all other conservatisms still apply.

Another aspect of this calculation, which was discussed before, is that if I assume a single failure which results in losing containment pressure, I would have both trains of suppression pool cooling available, and this calculation shows that I don't have to rely then on containment pressure.

MEMBER WALLIS: The licensee gave a presentation which the -- this depended on the initial pool temperature. This 169 you give is for a low pool temperature of 80 degrees. If it starts off at 90, I understand the peak is 185 according to that.

MR. LOBEL: I don't have the licensee's. I thought theirs was still conservative, so --

MEMBER WALLIS: So your 169 is a little optimistic perhaps, since you're also going back to a more realistic prediction of the pool temperature initially. I'm looking at Entergy slide 11.

MR. LOBEL: Yes, 169, case 2. They are still saying the other inputs are design basis.

MEMBER WALLIS: Yes.

MR. LOBEL: Which is my understanding.

Okay. And let me emphasize again that the Vermont Yankee calculations are done with the worst single failure assumption. This calculation just illustrates the margin that's available and the effect of crediting containment accident pressure on -- from just one assumption.

On 5-19 is another table that the licensee provided to the staff in response to a question we asked about conservatism. And let me go through the table a little, because this slide and the next slide I think help answer the question about sensitivities which has come up here other times.

The first item is the decay heat. The decay heat depends on the nuclear properties of the reactor core. The conservative assumption is to select properties which bound the nuclear properties, regardless of the specific reactor core and cycle.

This is what Vermont Yankee has done. A less conservative approach is to use a value derived for a specific cycle, and the difference between these two assumptions is a suppression pool temperature difference of two degrees.

The next item shows the results of another aspect of the worst single failure assumption. That is the loss of the -- one RHR heat exchanger. With the single failure of all injection pump -- with this single failure, all injection pumps remain in operation.

So if instead of these two LPCI, which is the same as RHR -- two LPCI and two core spray pumps injecting into the core, only one core spray pump was injecting, with many suppression pool cooling, a reduction in suppression pool temperature of eight degrees results.

This assumption of only one core spray pump injecting is reasonable for the time of peak suppression pool temperature, since the core has been covered for hours and the injection pump is only making up for boil-off from decay heat and spillage out the break.

MEMBER WALLIS: So this is something the operator could do.

MR. LOBEL: Right.

MEMBER WALLIS: If he finds he is getting not enough NPSH, he can switch off one of his core spray pumps.

MR. LOBEL: Right.

MEMBER WALLIS: And still have -- still has enough water.

MR. LOBEL: And I've had informal conversations with the Vermont Yankee operators in the control room, and we've kind of confirmed that this reasonable, and the operators would take actions to control the pumps.

MEMBER WALLIS: Well, I think rather than informal, you ought to have something that can go in the record and --

MR. LOBEL: Well, what's in the record, I think it's clear that the operators -- the assumptions that are made for the pump flow is that the RHR pumps are operating at runout flow, at full flow, for the whole transient, short term and long term. And I think it's clear that the operators, if they have any choice, aren't going to let the pumps operate at runout.

CHAIRMAN DENNING: Well, the question is, what do the emergency procedures tell them to do, isn't it?

MR. LOBEL: The emergency procedures are more in terms of -- of symptoms of keeping the suppression pool cool and keeping the core covered. And so that's what they're trying to do, and they would use I think their judgment about which pumps, you know, they need to do that. And the emergency operating procedures give them a choice of ways to keep the core covered and the suppression pool cooled.

The next item is a more realistic flow of suppression pool water through the RHR heat exchanger that results in a decrease in suppression pool temperature of .6 degrees. And the final one is an assumption of a more realistic RHR service water flow through the RHR heat exchanger, and this results in a decrease in suppression pool temperature of 4.8 degrees.

Going to the next --

MEMBER WALLIS: How about the surface water -- service water temperature? That makes a big difference, doesn't it?

MR. LOBEL: Well, that wasn't one of the variables they --

MEMBER WALLIS: Service water really is pretty darn cold at Vermont Yankee.

MR. LOBEL: But they're assuming a rather high value, I think 88 degrees.

MEMBER WALLIS: But 88 degrees is

miraculous.

MR. LOBEL: Yes.

MEMBER SIEBER: That's the standard temperature for most reactors.

MR. LOBEL: Yes, around there, 90 degrees, yes.

MEMBER SIEBER: Right.

MR. LOBEL: Okay. The next slide, 5-20. The licensee used these calculations to show the effect of conservative assumptions on NPSH calculations, and I modified their approach just slightly.

The licensee calculated the peak suppression pool temperature prior to extended power uprate to be 182.6 degrees. No credit for containment accident pressure was required for this suppression pool temperature. The peak suppression pool temperature as a result of extended power uprate is 194.7 degrees, and credit for containment accident pressure is needed.

If we take the peak suppression -- peak extended power uprate suppression pool temperature of 194.7 degrees, and subtract the sum of the conservatisms of the previous table, which is 15.4 degrees, we obtain a suppression pool temperature below 182.6 degrees, and containment pressure isn't required.

Don't forget that all other conservatisms such as the worst single failure are still included in this calculation.

To be more realistic, I took a root mean square of the sensitivity results, and this -- this is roughly one standard deviation. And subtracting this root mean square value, 9.6 degrees from the peak suppression pool temperature, the result is 185.1 degrees, and some credit for containment accident pressure is still required.

But don't forget all of the other conservatisms are still being applied, including the worst single failure and the fact that the pumps are operating at flow rates much greater than would be expected at the time of peak suppression pool temperature. The operator would be expected to throttle the pumps long before the times of peak suppression pool temperature.

One of the conservative assumptions the licensee makes is that the RHR pumps operate at runout flow for the duration of the large break LOCA, and, of course, the operator would be expected to throttle back from this flow early in the event.

Based on the results of a sensitivity study by another licensee, which I previously presented to the ACRS Thermal Hydraulics Phenomena Subcommittee, removing this one additional pump flow rate conservatism is probably sufficient to eliminate the need to credit containment accident pressure.

So this exercise illustrates the effective conservatism on the NPSH analyses, and I hope puts the Vermont Yankee need for containment pressure in some perspective. But, again, this discussion is only for illustration of the source of the need for crediting containment accident pressure. The Vermont Yankee calculations supporting the extended power uprate are done with all of these conservatisms included.

In the interest of time, I think we've already had a discussion this morning of containment integrity and operator actions, and the staff concurs with licensee's conclusion that no changes are needed to the emergency operating procedures.

Let me just do one more slide before I get to the conclusion, and that's 5-23. And one aspect of the effect of the extended power uprate on containment integrity can be seen in this table, and it shows the peak containment pressure as a result of the most limiting design basis LOCA for pre-extended power uprate conditions and for the extended power uprate. And the difference, using the same analysis methods and assumptions, is only .2 psi.

So from the point of view of the maximum pressure the containment will see after the most limiting design basis accident, there is essentially no difference, and the conclusion is that the effect of the extended power uprate on containment integrity in terms of peak containment pressure, peak containment accident pressure, is minimal.

MEMBER WALLIS: So we know that the peak containment pressure is somewhere between 7.8 or something, which you get by being conservative one way, and 41.8 if you're conservative the other way.

MR. LOBEL: Right.

MEMBER WALLIS: And in reality, it's somewhere in between.

MR. LOBEL: Right. And that's another indication of the conservatisms in the calculations.

MEMBER WALLIS: Yes. It would be very nice to get away from all of this and be realistic.

CHAIRMAN DENNING: When does the peak occur?

MR. LOBEL: The peak occurs very early in the first couple of seconds. The peak pressure is limited by the flow through the vents and the downcomers, and that kind of thing. There is a lot of resistance to flow there. You have to -- it has to force the water out of the downcomers, and so the peak occurs at the time the water -- the steam is trying to be forced into the Torus, into the wet well.

CHAIRMAN DENNING: And this constant pressure upgrade makes it so --

MR. LOBEL: Right.

CHAIRMAN DENNING: -- insensitive to this.

MR. LOBEL: Right. Well, yes, that and the fact that the most sensitive thing is the resistance of the vents in the downcomers, and that isn't changing significantly.

So let me just go over the conclusions. Credit for containment on 5-25. Credit for containment accident pressure is determined conservatively. A more realistic but still conservative calculation would show that credit is not needed.

Based on stringent testing requirements and the Vermont Yankee EPU safety analyses, containment integrity is a reasonable assumption. Credit for containment accident pressure has no impact on the operator, and the staff finds that the Vermont

Yankee credit for containment accident pressure is acceptable.

MEMBER WALLIS: Now, in the SER you go through a lot of discussion, or whoever wrote it, and then the conclusion is simply what's done is acceptable. There's no rationale presented in the SER for granting containment pressure credit. I think that's a -- this is an omission that should be corrected. You simply go through all the discussion, and at the end say that, no, it's all acceptable, but there's no explanation of why this containment pressure credit should be granted, and what the rationale is.

MR. LOBEL: Well, I tried to do that by discussing the conservatisms and the fact that --

MEMBER WALLIS: But that's okay. I think the discussion is fine, but it doesn't really -- it's not tied together with a rationale that leads to a conclusion. That's all.

MR. LOBEL: Okay.

CHAIRMAN DENNING: Have you considered -- how significant is the integrated leak rate test towards assuring the high integrity reliability of the containment, and here we have this step where we're going to go from 10 years to 15 years. Should one be reconsidering that?

MR. LOBEL: We've talked about that. I think Mr. Stutzke can address that better, because the change in frequency is really based on risk, and he has been involved in those discussions. But I think the -- just an overview that the change in risk in going from 10 to 15 years is pretty minimal, and that was the basis for the change.

CHAIRMAN DENNING: How about going to five? Just because of added assurance.

MR. LOBEL: Going to -- test every five years?

CHAIRMAN DENNING: Test every five years. Does that give us a higher degree of -- well, we can see what --

MR. LOBEL: I don't know the answer to that. I imagine it would, but whether it's -- it would have to, but whether it's significant or not I'm not sure.

MEMBER WALLIS: I think it's not just a question of risk significance; it's a question of making a proper case so the public doesn't get confused. And the idea that you're only going to do something once every 10 years needs some sort of explanation. Or maybe it doesn't cost that much to do it a few more times and reassure people.

MR. LOBEL: Well, it's a pretty expensive test, and it has a large impact on an outage, because you have realize that while this test is going on, there can't be any work done in containment. So essentially while this test is being done, there isn't a whole lot of other work that can be done on the outage, so it does have an impact.

But let me also point out that this is just the ILRT for the overall containment that the frequencies of the Type B and C tests, the penetrations and isolation valves, haven't been trained -- changed since Option B. And they are based on -- they are performance-based.

As long as there is good performance, they can extend the interval to five years. If a penetration fails a test, then they have to test more often until -- until they have two successful tests, and then they can go back to five years again.

MEMBER SIEBER: Yes. The Type B and C tests are testing joints, as opposed to a Type A test which tests the shell. Okay. And the likelihood of the shell leaking is -- other than corroding all the way is minuscule.

MR. LOBEL: Right. And this test really

-- the ILRT is really a leak test. It's not meant to be a structural test per se, although obviously it does test the --

MEMBER WALLIS: Well, the sort of thing you worry about is what we heard about in another plant where someone drilled holes in order to do something. And it happened that the drill holes -- the drill went into the containment.

That's what you worry about is something that someone did inadvertently which was not detected. It's not as if the thing is solid and you don't expect anything to happen. That's fine. But there could be things that you didn't know about.

MR. LOBEL: Yes. Well, there was actually a case of that. I don't know if that's what you're referring to, but there's a case of that that's included in the database that's used for the ILRT extension.

CHAIRMAN DENNING: Okay. Thank you. Let's move on.

MR. THADANI: Rich, just one --

MR. LOBEL: Yes.

MR. THADANI: Rich, your conclusion is pretty encompassing it seems to me. But you only talked about LOCA, and you didn't talk about other accident scenarios.

MR. LOBEL: Well --

MR. THADANI: So I feel that's going to come at the next meeting.

MR. LOBEL: Well, I'm not sure there's going to -- I don't know. It's up to the committee whether there's going to be a next. There wasn't supposed to be, but the SER addresses the other events. And I did talk a little about the analysis methods that were used for the --

MR. THADANI: I think we talked about you're going to cover ATWS, I believe, at the next meeting.

MR. LOBEL: Yes. Well, I was saying that -- you were saying that ATWS doesn't require realistic assumptions, but actually the licensee made some -- I'm sorry, some conservative assumptions, and I was saying that actually they did include some conservative assumptions.

MR. THADANI: But there is a difference here in terms of the operator actions. They have to be conducted earlier now than in the earlier -- previous case.

MR. LOBEL: Well, we're talking here just in terms of pump NPSH and --

MR. THADANI: And I'm talking about -- I understand. I'm talking about that aspect also.

MR. LOBEL: Okay.

CHAIRMAN DENNING: Okay. Thank you.

Marty?

MEMBER SIEBER: Let me ask, before you disappear, one more question. Which decay heat model does the licensee use?

MR. LOBEL: The 1979 with the 2 sigma uncertainty.

MEMBER SIEBER: Okay.

CHAIRMAN DENNING: So when you showed that variation, it was with that uncertainty in there?

MR. LOBEL: Yes.

CHAIRMAN DENNING: Oh. Because that also is significant conservatism. I'm surprised you didn't identify it.

MR. LOBEL: Well, I did say it in my list -- it's on my list of conservatisms.

MR. STUTZKE: Good afternoon. I'm Marty Stutzke, a Senior Reliability and Risk Analyst in the Office of Nuclear Reactor Regulation. And I'm here today to talk about the scoping analysis the staff performed to look at the proposed credit for containment accident pressure.

I realize that the staff uses the term "containment accident pressure." The licensee, in its documentation, uses "containment overpressure." So you may see some confusion in my viewgraphs. They're basically the same that way.

Next slide.

I thought I would begin, for the benefit of the public here, to briefly explain how the NRC uses risk information in reaching its regulatory decisions. Specifically, the proposed containment overpressure credit at Vermont Yankee.

This is somewhat of a continuation of a dialogue that the staff has had with this committee in September and October of this year. Specifically, I'm referring to the proposed revision to Regulatory Guide 1.82, Revision 3. And I understand we're here to talk about Vermont Yankee and not that Regulatory Guide, but they have become intertwined to some extent. and so, in fact, the VY review has revealed some issues with our own regulatory guidance.

In order to help your understanding of the chronology, I have developed one for you, so you understand what we considered and when we asked questions, and so forth, and it will try to connect the relationship between the VY review and the Reg.

Guide to some extent.

And, finally, I'll give you the details of the staff scoping risk evaluation.

Next slide.

I suppose the appropriate way to begin a discussion of the staff's use of risk information is to remind the committee and the public that in 1995 the Commission -- that's the actual five-member body -- as opposed to people like me, I work for the staff -- but they issued a policy statement which we call the PRA policy statement, and encouraged a greater use of PRA techniques to improve safety decisionmaking and regulatory efficiency.

The risk evaluations here for the proposed Vermont EPU are a direct result of that policy statement. More to the point, in 1997, a COM was issued by Commission Jackson -- Chairman Jackson -- COM-SAJ-9708, and the purpose of that COM was to talk about the nexus between compliance and safety.

One of the ramifications of that memo was the need to consider risk information when reaching regulatory decisions, even when evaluating non-risk-informed license amendment requests. Additional guidance has been developed elsewhere, this regulatory issue summary 2001/'02, and, finally, Standard Review

Plan Chapter 19, Appendix D.

Just by way of --

MEMBER WALLIS: Is there anything in this Review Standard Number 1 about this?

MR. STUTZKE: Are you talking about Reg. Guide 1. --

MEMBER WALLIS: No, Review Standard Number 1.

CHAIRMAN DENNING: He means RS-001. Yes, there's a section in here on --

MR. STUTZKE: Yes, I'll get to that.

MEMBER WALLIS: I was wondering why you didn't mention it here. That's --

MR. STUTZKE: I'll get to it.

MEMBER WALLIS: Okay.

MR. STUTZKE: Next slide.

As with most of the things we're discussing, it's rather convoluted. But by way of clarification, a license amendment request is risk-informed when it's submitted under a risk-informed Reg. Guide, like Reg. Guide 1.174.

MEMBER WALLIS: When the whole thing is, right?

MR. STUTZKE: Right. Just because it has some risk information in it doesn't make it a risk-informed application. Okay?

Next slide.

Well, as indicated, the Code of Federal Regulation gives the staff the authority to require the submittal of information with connection to the license amendment request. Specifically, Standard Review Plan Chapter 19, Appendix D, provides the process by which we obtain risk information about non-risk-informed license amendment requests.

The process is basically as indicated here. The staff -- that's people like me -- working through the project manager can go to the licensee and request risk information. In other words, we've reached a sticky point. We need to understand something.

Here is where it gets difficult. Because it's not risk-informed, if the licensee declines, the burden shuffles over to the staff to show that the proposed license amendment request raises questions of adequate protection. Okay? And, therefore, we need the risk information in order to decide whether or not that's true.

Now, you have to realize it's not just -- the staff has to show, but the staff has to show the senior NRC management and the Office of the General

Counsel, and actually to the Commission itself, okay, so this second sub-bullet here is not to be undertaken lightly.

Generally, when we seek risk information, we expect licensees to address the five key principles of risk-informed decisionmaking that are listed in Reg. Guide 1.174. My next slide will list those, so that you understand what they are.

Now, again, if a licensee declines to provide the risk information, even after we have demanded it, then the license amendment request could be denied, if we can't reach a decision on purely deterministic grounds like that.

Specific to extended power uprates, none of them so far have been submitted as risk-informed license amendment requests. They have all been non-risk-informed.

However, as Dr. Wallis had noticed, RS-001 Matrix 13 talks about the staff's expectation for licensees to submit risk information, because there's a concern that the proposed extended power uprate could create special circumstances that rebut a presumption of adequate protection from compliance with regulations.

Now --

MEMBER WALLIS: So when you get to the end, you can ask for it, and you've got it? Go ahead.

MR. STUTZKE: The requirements in RS-001 are consistent with Reg. Guide 1.174. But it's tailored specific to extended power uprates. In other words, it lists lessons, and we've learned over conducting several power uprates -- extended power uprates over the years, and tries to guide reviewers as to the sorts of issues that need to be assessed like them.

But realize that our purpose of using the risk evaluation and requiring licensees to submit them is we're attempting to probe the proposed extended power uprate to see if the special circumstances exist.

MEMBER WALLIS: Can I look at the first bullet here? Are you -- oh, I'm on the next slide. I'm sorry. Are you on the next slide?

MR. STUTZKE: I'm on 6-5.

MEMBER WALLIS: Are you still on 5?

MR. STUTZKE: Right.

MEMBER WALLIS: I'm sorry. I thought you had gone to the next one.

MR. STUTZKE: But it's important you realize that we're not -- when we're seeking risk information for a proposed EPU, we're after -- to detect if we can find something that rebuts --

MEMBER WALLIS: Right.

MR. STUTZKE: -- a presumption of adequate protection. Okay?

Let's go to 6-6. The top bullets list the actual five key principles. The proposed changes meets current regulation.

MEMBER WALLIS: Can I look at the first one here? We were told there was no regulation regarding containment overpressure credit. If there were a regulation which said, "Thou shalt not give containment overpressure credit," then that would mean that you couldn't use one certain core, because you're violating the current regulation."

MR. STUTZKE: Well --

MEMBER WALLIS: So there's sort of a window of opportunity by being vague about --

MR. STUTZKE: This is an abridged version. It says it either meets current regulations, unless an exemption to the regulation is --

MEMBER WALLIS: Okay. So there is a way around it. Okay.

MR. STUTZKE: Okay.

MEMBER WALLIS: Thank you.

MR. STUTZKE: The second key principle was consistency with the defense-in-depth philosophy, and I'll speak to some detail about that.

MEMBER WALLIS: I always found it difficult to be consistent with a philosophy. I can be consistent with a regulation, but this is a rather -- this is liable to all kinds of interpretation, if you're trying to be consistent with a philosophy.

MR. APOSTOLAKIS: That was put there deliberately, Graham, because you can never be consistent with defense in depth.

MEMBER WALLIS: Try to explain to the cop when you're going too fast on the highway that you're consistent with some philosophy.

(Laughter.)

MR. APOSTOLAKIS: That's what we're trying to do, to get away from a compliance culture.

(Laughter.)

MR. STUTZKE: Okay. The third key principle was maintain sufficient safety margins. Should I cringe now, Dr. Wallis?

MEMBER WALLIS: Yes, that's fine. That's okay.

MR. STUTZKE: The fourth key principle is increases in risk should be small and consistent with the intent of the Commission's safety goal policy. And, finally, the impact of the proposed change should be monitored using performance measurement strategies.

I think what's important to point out here is that we use an integrated decisionmaking process. Licensees need to address all five principles. Staff will weigh the responses to the licensee against each principle in order to reach its decision.

In other words, we don't reach -- when we're talking about risk-informed license amendment request, it's not judged strictly on whether or not it meets a numerical risk acceptance criteria. As a matter of fact, we have no risk acceptance criteria; only guidelines. Okay? A licensee could meet the guidelines and still be rejected.

MEMBER SIEBER: What would be the basis for rejection in those circumstances? Uncertainty?

MR. STUTZKE: Could be uncertainty. But the risk guidelines speak to the fourth principle. Okay. So he could be rejected because of issues on defense in depth or safety margin or traditional engineering.

MEMBER SIEBER: Okay.

MR. STUTZKE: Okay. Besides 6-7 and 6-8 are my chronology of the risk evaluation that has gone on so far, I put this here as kind of your road map through the process. But I think it points out three things. One is we've been working to understand the risk implications of the proposed containment overpressure credit since we first got the EPU application from Entergy. My first RAI to Entergy addressed overpressure, and that was issued in December of 2003.

So you could meet the guidelines and still be rejected.

MEMBER SIEBER: What would be the basis for a rejection in those circumstances? Uncertainty?

MR. STUTZKE: Could be uncertainty. But, again, the risk guidelines speak to the fourth principle. Okay? So you could be rejected because of issues on defense in depth or safety margin or traditional engineering.

MEMBER SIEBER: Okay.

MR. STUTZKE: Okay. Slides 6-7 and 6-8 are my chronology of the risk evaluation that has gone on so far. I put this here as kind of your road map through the process, but I think it points out three things.

One is we have been working to understand the risk implications of the proposed containment overpressure credit since we first got the EPU application from Entergy. My first RAI to Entergy addressed overpressure. And that was issued in December of 2003.

Second of all, as you will see here, there have been numerous interactions between the staff and you guys concerning the proposed revision to reg guide 1.82. At one of those meetings, Dr. Kress had suggested we expand our risk evaluation to consider more types of initiating events. And we have done that. That is my way of letting you know I actually listen to what you tell me.

MR. APOSTOLAKIS: But did you actually include late containment failure in your --

MR. STUTZKE: I'll get to that.

(Laughter.)

MR. APOSTOLAKIS: You listen up to a point, right?

MR. STUTZKE: Finally I would like to point out that the version of the staff's safety evaluation report that you have now was issued on October the 21st. That is the same date that we got the partial risk evaluation from Entergy, supplement 38.

Supplement 38 actually contained about 30 pages of text that addressed principles number 1, 2, 3, and 5. You'll notice 4, which is my forte, the actual risk assessment, wasn't supplied until October the 26th. That supplement alone has 303 pages with the result that we're still in the process of reviewing it.

MEMBER WALLIS: They're not pages of text in the normal sense.

MR. STUTZKE: There are text. There are computer printouts.

MEMBER WALLIS: The text is very brief. Most of the pages are details of the PRA printouts, aren't they? They're pretty brief.

MR. STUTZKE: Yes. But it's possible to ferret out. When you read that, you understand what they're actually --

MEMBER WALLIS: Some people can ferret it out, yes. It would help to have more guidelines to know how to interpret all those pages of printout.

MR. STUTZKE: Yes. It's a case in point. I expect to ask RAIs of the licensee to --

MEMBER WALLIS: Clarify.

MR. STUTZKE: -- clarify what has gone on. Okay. Let's talk about the scoping risk evaluation that the staff performed that's on slide 6-9.

As was discussed earlier today, it seems clear that a realistic thermohydraulic calculation of available net-positive suction had indicates that no containment overpressure credit is actually required.

MEMBER WALLIS: Do you know what realistically conservative means? I know what conservative means. I know what realistic means. Somewhere in between is this hybrid, which is neither one thing nor the other.

MR. STUTZKE: Well, the phrase was coined by our Chairman. So I will defer to him.

MEMBER WALLIS: But you must know what it means if you make this conclusion. So maybe you can tell us --

MR. STUTZKE: Specifically with respect to --

MEMBER WALLIS: When we next meet, you will tell us what you really mean, how to interpret that?

MR. STUTZKE: Well, specifically with respect to containment overpressure, from discussion with the licensee and Mr. Lobel, one of the conservatisms he had listed there, no overpressure credit is required.

MEMBER WALLIS: I think that's what you

mean, that Mr. Lobel has 15 conservatisms he can remove. He removed one or two. And the problem goes away. You think that has now become realistic enough that you can reach a decision. It's a judgment of some sort.

MR. STUTZKE: That's right. But, as you had noted earlier today, PRAs' attempt to model the actual plant attempts to be a realistic analysis like this. So now we have raised the philosophical issue that you had before.

What is the change in core damage frequency from credit in the containment overpressure? Realistically the number is zero because the overpressure is not required realistically.

So when I discussed the staff's scoping risk evaluation, I think the appropriate way to look at it is that we're doing a sensitivity analysis to try to capture modeling uncertainties.

The uncertainty is in the success criteria. Do you need the overpressure or not? If you do, it changes the systems required to prevent core damage in the risk assessment. And that is something we can examine pretty well.

So in order to do this analysis, I made the assumption that core damage will occur only if all of the following conditions occur. You need to discharge reactor coolant into the suppression pool in order to heat it up. You need to run either the low-pressure core injection or the core spray pumps in order to provide inventory control or decay heat removal. You have to lost containment integrity, which is the loss of overpressure, which leads to the inadequate net-positive suction head. And, finally, as a realization, the operator needs to get involved to initiate suppression pool cooling.

MEMBER WALLIS: On bullet number 2 here, you don't have to run all the pumps, do you?

MR. STUTZKE: Not in PRA space.

MEMBER WALLIS: So your success criterion is that one pump works?

MR. STUTZKE: One pump works.

MEMBER WALLIS: That's good enough. That's your success criterion.

MR. STUTZKE: That's right.

MEMBER WALLIS: One out of four essentially?

MR. STUTZKE: One out of four. Now, I think I would like to emphasize the last bullet there is how the operator got involved. If containment integrity is lost, say, before the LOCA occurs, it's lost and it's undetected and the plant is operating that way for some time or there is a failure perhaps of the containment isolation system so that the overpressure is lost right about time zero like this to the point where the containment never pressurizes following the LOCA, that doesn't immediately cause a loss of net-positive suction head to the pumps. The reason is there's a lot of water in the suppression pool at room temperature. And it takes time to heat that inventory up.

Now, I've described to this Committee before I have done a hand calculation just looking at the massive water in the suppression pool and indicated a pretty simple decay power curve and concluded it takes about four hours to heat this up.

Realizing I'm not a thermohydraulic analyst, this is a freshman-level type of calculation, we asked the licensee to make a real thermohydraulic calculation. They ran the MAP code, and they confirmed that four hours is about the right time.

MEMBER SIEBER: Isn't it a fact that if you lose containment integrity, now you've got a hole in containment and you never get to the temperatures that you would otherwise achieve if you had containment integrity because the heat has gone out?

MR. STUTZKE: That is true.

MEMBER SIEBER: Did you take that into account?

MR. STUTZKE: No. We're not accounting that.

MEMBER SIEBER: That's a --

MEMBER WALLIS: Are you running the RHR system when you are cooling this pool?

MR. STUTZKE: No. This four-hour heat-up is if all RHR pumps have failed, all --

MEMBER WALLIS: Are you assuming some other things fail as well?

MEMBER SIEBER: Yes.

MR. STUTZKE: Yes. Okay.

MEMBER WALLIS: So this is realistically conservative or this is overly conservative?

MR. STUTZKE: I think it's pretty realistic.

MEMBER WALLIS: If all pumps fail, all of RHR's pumps fail?

MR. STUTZKE: Well, what we're trying to get on is a timing here.

MEMBER WALLIS: I know. I understand.

MR. STUTZKE: How much time could we possibly have here?

MEMBER WALLIS: So you really do a conservative analysis? If all the heat goes into the pool, I don't see how anything could be much more conservative.

MR. STUTZKE: Okay. 6-10. So let's talk about how the scoping risk model was developed. It's basically a modification of the SPAR models, Standardized Plan Analysis of RISK models, that are developed by the Office of Research. These models are simple PRAs that are used to drive the significance determination process as well as the accident sequence precursor program.

The SPAR model was benchmarked against the licensee's PRA back in 2003. Okay?

MEMBER SIEBER: So that's pretty good.

MR. STUTZKE: Well, we understand where the disagreements are --

MEMBER SIEBER: Okay.

MR. STUTZKE: -- is the appropriate way to characterize it. The SPAR model itself has 11 transient initiating events, 5 types of LOCAs, small, medium, and large, as well as inadvertent open relief valves and interfacing system LOCAs. It models what I will call special sequence types, such as station blackout, stuck-open relief valve scenarios, and countless like this.

You have to realize that the SPAR model is only what we call a level I PRA type of model. In other words, it ends at a consideration of core damage. So it's not considering the consequence of the behavior of the containment to that much. It doesn't consider external events, like seismic or fires or things like this.

6-11. What you have here is a picture of an event tree. This is the logical modeling tool that risk analysts use to delineate accident sequences. I thought I would put that up so the licensee could actually see what I was doing in PRA space. And I thought it would be of some interest to the public.

On the left-hand side of the tree -- first of all, there are many, many trees like this. I picked perhaps the most simple one, which was large break LOCA. On the left-hand side of the tree, you see the initiating event: large LOCA. That is the single line.

To read this tree, the upward branches, when it goes upwards on the page, that is success. The downward branch is failure. Okay? So you read the first event, the large LOCA occurs. We asked the question, is the reactor shut down?

The reactor is not shut down. You transfer down to sequence here, number 27, all the way at the bottom of the page. We say core damage occurs, end of discussion.

MEMBER WALLIS: Seventeen? Number 17?

MR. STUTZKE: Seventeen is all the way at the bottom of the page. If the reactor is shut down, we then ask, does the vapor suppression system work? If the vapor suppression system fails, we go to the bottom of the page. It's sequence 16. And we say core damage occurs and so on and so forth through this tree.

The essence of the PRA, what we want to do is calculate the probabilities of whether it goes up or it goes down. Now, that's a perhaps overly simplistic explanation of how we go about calculating the probabilities, but that's the nature of it.

What I did in order to handle the proposed containment overpressure credit was I introduced an event in the middle of this tree called containment integrity. Okay?

And you'll see that coming into that event is either the successful operation of core spray or LPSI pumps. If we're running one of these systems and the containment integrity is lost, what happens?

Okay.

Realize the upward branch here means at least one core spray pump or one LPSI pump are working. If the containment integrity is lost, we come down and we ask a question about the suppression pool cooling system and the reason goes back to that four-hour time that we had calculated before, it takes time to heat up the suppression pool to the point where the pumps actually cavitate. All right?

The only difference between the top consideration of suppression pool cooling and the bottom is the timing. In the bottom, the operator has to get the system lit off within the four hours.

On the other hand, if containment is actually tight, it's withholding pressure, there is still a need to run suppression pool cooling. That heat is going to go someplace. And it goes into heating up the suppression pool. And eventually you could overpressurize the containment like this.

The time frame that's much longer, that's a 24-hour time frame. Those of you familiar with reactor safety study, that is sequence TW being involved in here, the real long-term heat-up.

MEMBER SIEBER: What was the assumed containment pressure at failure? Is it realistic or the design pressure?

MR. STUTZKE: Normally for PRA we use the realistic failure probability.

MEMBER SIEBER: That would be like 100 pounds?

MR. STUTZKE: A hundred pounds or so. I don't know the exact number here.

MEMBER SIEBER: Yes. Okay.

MR. STUTZKE: So the point being here is when you read this, you will see I have introduced two additional sequences here that deal with the loss of containment integrity and, therefore, the loss of containment overpressure like this. As I said before, I had done these or all of the initiating events, all of the events in the PRA. Okay?

Now, one of the ingredients we need in order to calculate the risk is we need data to quantify the probability of loss of containment integrity. And it's broken into three parts: what I'll call preexisting undetected leaks; containment isolation system failures, which also include failure to close the main steam isolation valves. I'd added the latter one in on the MSIVs after some discussions with Mr. Sherman. I appreciate him finding the oversight like that.

As far as the containment isolation system failures and the preexisting undetected leaks, I extracted data from the licensee's recent submittal in the last couple of months for a one-time extension of the ILRT frequency to 15 years. This, in turn, is based on a report issued by Electric Power Research Institute, but it's an older sort of report.

What you need to realize is the actual data for the size of leaks we're talking about is rather sparse. In fact, there have never been any failures. So in order to generate a probability, one is forced to rely on Bayseian statistics with not informative prior distributions. And I'm glad George has already left because we would be discussing this the rest of the day.

But realize there is not strong evidence here that containments fail with holes big enough to create problems to lose the overpressure.

MEMBER SIEBER: Well, there have been some scaled or containment failure tests. Did you use any of that data?

MR. STUTZKE: No, no. I'm relying strictly on this new EPRI --

CHAIRMAN DENNING: And if you did, you wouldn't get into that regime where you get that kind of --

MR. STUTZKE: I wouldn't think so, no.

CHAIRMAN DENNING: No.

MEMBER WALLIS: The most likely failure is a human action, where something which appears to be bolted on was not bolted on properly or something or something wasn't installed properly during some unexpected maintenance or something like that, but that is most likely.

MR. STUTZKE: Right.

MEMBER WALLIS: It's not likely that the thing is going to pop as a result of the pressure.

MR. STUTZKE: Common cause failure of containment isolation valves, things like that, show up to be important.

MEMBER KRESS: By the way, I think George would have approved of the non-informative prior invasion approach.

MR. STUTZKE: Right. The reason why I wanted to point that out is that when you get into this regime, right, you had heard the licensee talk about how big a hole he needs, right, 27 L_a, right?

Well, the number that I have is for 35 L_a, but, in fact, there have never been any failures of either size. So you're in this problem. It's very analogous to calculating the frequency of LOCAs. And you're well aware of the effort the Office of Research undertook in the 5046A effort to generate that curve.

MEMBER WALLIS: Yes.

MR. STUTZKE: Okay. As far as the human failure events, the one we're talking about is operator-initiated suppression pool cooling within four hours.

There are two types of human errors. There's what's called a cognitive error. That is, the operator doesn't diagnose what's going on in time. He just runs out of time or he can't decide what he should be doing like this.

Maybe the symptoms are confusing. In order to calculate that probability, we're using a report from the, again, EPRI cause-based decision tree method.

I think one of the reasons why that one was picked is it was developed in part by Dr. Garrett Perry. He's now the senior-level adviser where I work. So we had some comfort with it.

The other part of the human errors are what are called action errors or implementation errors. Now the operator understands what he's doing, but he pushes the wrong button, reads the wrong gauge, these sorts of things like that.

I'll put this into some discussion here about the use of ATHENA. Again, it's a pity George is not here. ATHENA, a technique for human error analysis, has been evolved by the Office of Research over many, many years.

In the end of the summer, we received a draft addendum to NUREG 1624. The addendum is entitled "The ATHENA User's Manual." The office, NRR, had sent comments back on the use of ATHENA in early October of this year, so about six weeks ago. And we have some reservations with what is going on there.

So based on discussions within NRR, I decided I would not employ the ATHENA methodology at all here. But you will see I have done sensitivity with many, many other human reliability techniques to get at it.

Okay. As far as the scoping risk model on slide 6-13, looking at truncation limits on the order of 10^{-12} per year, which is extremely low frequency like this, we have done full parametric uncertainty analysis, 5,000 Monte Carlo samples. It seemed like it converged appropriately.

We're regenerating minimal cut sets every time we do a sensitivity analysis case because of the issues over truncation. Again, I pointed out we had done parametric uncertainties. I also looked at modeling uncertainties on how big a hole you actually need to depressurize; another one concerning the MFIB success criteria; and, finally, the human reliability.

MEMBER SIEBER: How big a hole do you need?

MR. STUTZKE: My best model is assuming 35 L_a. And the reason is that is the number in that EPRI report that was the justification behind the one-time 15-year ILRT.

MEMBER SIEBER: Okay.

MR. STUTZKE: That 35 L_a is presumed to be a large release.

MEMBER SIEBER: Right.

MEMBER WALLIS: How big a hole?

MR. STUTZKE: Like that.

MEMBER WALLIS: How big?

MR. STUTZKE: Physically I don't know. My guess is a little over a half-inch or so, something like that.

So the results of the analysis are like this. The change in core damage frequency solely due to the proposed overpressure credit is on the order of 6 times 10^{-8} per year like this. And I'll point out that is a real mean value. That is not a point estimate. Okay?

I have also provided probability ranges.

MEMBER WALLIS: The licensee got four percent or something like that?

MR. STUTZKE: It's about 2.4 percent.

MEMBER WALLIS: The licensee got something slightly bigger, I think, but it was --

MR. STUTZKE: Right. This number is an order of magnitude higher than mine. That's why they can expect a lot of RAIs while we try to unravel this situation like this.

At face value, if I take this --

MEMBER WALLIS: Well, let's see. If you are still writing RAIs, how are we going to make some kind of a decision in two weeks, three weeks?

MR. STUTZKE: We will write very fast.

MEMBER WALLIS: They will answer very fast? They will answer very fast, too?

MR. STUTZKE: I think so. I think so.

If I take these numbers and put them into the risk acceptance guidelines from reg guide 1.174, you find out that is, in fact, a small change in core damage frequency.

One of the things I would like to point

out about these risk acceptance guidelines in that regulatory guide, I've heard a lot of discussion today, "Gee, if it's below 10^{-6}, it's okay." And the implication is if it's higher than 10^{-6}, there's something wrong. That's not true.

The risk acceptance guidelines actually allow delta CDF to go above 10^{-6} as long as the baseline core damage frequency is below 10^{-4} per year. I'll hold up -- I don't have a viewgraph of it. That's what the guidelines actually look like. And you have to be in the gray area, not the black. So don't be fooled. And numbers above 10^{-6} are not necessarily bad. Okay?

Now, on slide 6-15, I've tried to provide a breakdown of the risk profile, what's driving the -- you can see the CDF is dominated by core damage accidents from transients.

The sorts of accidents we're most interested in, LOCA stuck-open relief valves, are relatively small contributors overall. The largest change was in the stuck-open relief valve sequences. That's about 80 percent of the total increase I saw, was in stuck-open relief valves.

On the next slide, I showed importance measure for the events that I introduced into the tree to look at the overpressure credit. They vary. It depends on which measures to which event is most important. But, as you would suspect, these preexisting undetected containment leaks are important, as is the operator error, as is the failure containment isolation system. The only one that doesn't seem to be important are the MSIV failures.

So in order to get at these modeling uncertainties, I did some sensitivity studies. Starting on page 6-17, I looked at sensitivity to containment leak size.

Now, for the public, in order to understand that, the big dot is mean value, the average core damage frequency. The height of the bar indicates a 90 percent probability bound around that mean. Okay? So it gives you an idea of how uncertain we are in the PRA just due to the parametric uncertainties.

My point here is that when you compare these and you say, "Oh, you know, the core damage frequency went up by a factor of two," if the uncertainty is two orders of magnitude, it's not as important an effect, as you might expect.

So my baseline was 35 L_a leak size. I had data on actual ILRTs from the separate report, the number of failures in there, and put that probability in. So this is saying if you had a leak now at one L_a, let's assume you've lost the overpressure.

And you can see the mean value goes up by about an order of magnitude. But, still, in comparison to reg guide 1.174 acceptance guidelines, it's okay.

CHAIRMAN DENNING: Marty, I hate to interrupt you, but I think we need to talk a little bit with the Advisory Committee here. We really should be moving out of this. And I think that it's pretty obvious here what the magnitude is of results that Marty has.

MR. STUTZKE: Right.

CHAIRMAN DENNING: I don't know whether we ought to go to a conclusions -- there is a question on the defense in depth. Is there something here to say on defense in depth?

MR. STUTZKE: Oh, absolutely. Let's jump to 6-21.

CHAIRMAN DENNING: Continue.

MR. STUTZKE: Okay. One way to look at defense in depth that PRA is helpful in doing is looking at the balance between accident prevention and mitigation. And so I attempted to do that by looking at the impact of the proposed credit on the conditional containment failure probability.

The CCFP includes both small releases, large releases, early, late. It's all releases put in there. Okay? And realizing the situation we're talking about, if containment integrity is lost, it leads to some sort of release.

I'm not willing to commit myself at this time, whether it's big or small, late or early, like that, but it's some sort of release. But it plays in well to the calculation of CCFP. And one can come up with a fractional change in conditional containment failure probability as a function of all of the others in here.

But, jumping to 6-23, if I look at that, I put in generic numbers for BWR mark I that I took out of the IPE studies. And you can see there's a relatively small change in the conditional containment failure probability as a result of the proposed containment overpressure credit. That suggests the existing balance is not significantly perturbed.

Other things in here when we were talking earlier before about how to evaluate defense in depth, standard review plan provides four objectives, talks about it, doesn't significantly increase existing challenges to the integrity of barriers. We don't change the failure probabilities of barrier, just not introduce newer, additional failure dependencies that significantly increase the likelihood of failure. I'll emphasize the word "significant." And, finally, redundancy and diversity are adequate to ensure compatibility with the risk guidelines.

Okay. So I have an evaluation here starting on 6-25 against these criteria. Crediting containment overpressure doesn't affect the frequencies of LOCAs or transient-induced stuck-open relief valves. It doesn't affect the normal plant operation. It won't affect the probability of containment failure. Containment will either fail or not, as it always says.

MEMBER WALLIS: Can I ask what is going to happen now? I mean, you're telling us this, but it's not yet in the SER.

MEMBER KRESS: Right.

MEMBER WALLIS: Something like this will be in the SER?

MR. STUTZKE: Yes.

MEMBER WALLIS: And it will also have the RAI responses considered and all of that? We can see this by the time we next meet with you folks?

MR. STUTZKE: It will have the results of the RAI responses but not the --

MEMBER WALLIS: I think we ought to have the up-to-date SER hopefully by the time we meet with you again.

CHAIRMAN DENNING: I am actually going to draw this to a conclusion now, Marty.

MR. STUTZKE: Okay.

CHAIRMAN DENNING: Thank you. I think we really do understand this.

MR. STUTZKE: Yes.

CHAIRMAN DENNING: And we will look at it more carefully.

MR. STUTZKE: Great.

MEMBER KRESS: These slides relate to the containment overpressure, but you're not drawing the conclusion about the power uprate?

MR. STUTZKE: No. I'm here specifically to the containment overpressure.

MEMBER KRESS: Right. Okay. I wanted to get that clear.

CHAIRMAN DENNING: We now are going to move into a public comment period. And we have a number of speakers. Are there any congressional staffers here? If they are, would they like to make a presentation or a statement? Any public officials who are here who would like to make any statements?

(No response.)

CHAIRMAN DENNING: Okay. Now we're going to ask you, the speakers, to come here to the front. I'm going to move these out of the way. Can you move those out of the way? And we're going to have people sit up here at the table.

We have right now 35 speakers. So we only have until 5:30. So if things move as well as they did yesterday, we should be able to accommodate those.

If we run out of time, then people are going to have to submit their statements. And they can do that through Ralph. We'll again tell you at the end how to do that.

MEMBER WALLIS: Mr. Chairman, I have a question about the scope of these statements. I mean, are any statements having anything to do with nuclear power allowed or is it specific to Vermont Yankee and the uprate? Because that's really what we're looking at.

CHAIRMAN DENNING: Well, I --

MEMBER WALLIS: I just wonder. I mean, the public can say anything they like.

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: But I would hope that people who have the most to say that will influence our decision directly would actually be allowed to say it.

CHAIRMAN DENNING: Certainly. People can say whatever is on their mind, but obviously those things that relate most directly to the Vermont Yankee uprate have the greatest impact on us.

The first speaker, then, will be Rod Gander. And, again, please come up to the microphone here, this one up here. On deck is Joe Hoppenfeld. And in the hole if you are discus is Paul Blanch.

MR. GANDER: Well, thank you. Briefly I would like to -- can you hear me? I'm not sure this is working.

CHAIRMAN DENNING: Yes.

MR. GANDER: Okay. Fine. To identify myself, I am Rod Gander. I am the state senator living in Brattleboro serving in Montpelier.

I will try to cut this in half and be about five minutes because I know you have so many people. Unfortunately, I really do think we need to talk about this in context.

I certainly understand your role. For instance, I didn't understand much of what has just been said the last hour. So I had to keep my eyes open this way because I am not a scientist. And I couldn't follow it.

Certainly I understand your role is to give advice to the NRC about safety. So I understand that. But at the same time, we are all human. And I think that we have to look at this thing in context. I really do. And I want to talk about my frustration over a period of time, not with you, my frustration with the process, the frustration of most of my friends and neighbors.

First of all, my understanding is that you do do the independent safety review, and we're actually counting on you. We really are counting on you. This is about the last opportunity that we have to speak and so on.

I think that all of us really believe that you are honorable guys. I really mean that. If there had been any discourtesy at all, it only comes from the frustration that we have faced in this process over the last two or three years.

I think that probably in your service, you have faced frustration at times as well in attempts to get information and also in not having recommendations that you have made to the NRC be adopted by the NRC.

So you don't have total control. We understand that. But you are a powerful voice, very powerful voice. And we hope to convince you of the merits of our case.

First of all, we worry about the democratic process. We have had two referenda. They really are plant or no plant. That's what it amounts to, no matter what the wording is and so on. And they were overwhelmingly that we do not want the plant relicensed and also that we do concomitantly want to go through the uprate process, which will lead to the plant being relicensed. I feel strongly about that. I will go into that in a minute or two.

In those referenda, in one of them, all of the towns except two in the County of Windham voted overwhelmingly against the company position in the uprate and the relicensing. In the other ones, all but one voted and so on.

So you exercise your democratic privilege, which we have done. And I'm not blaming you folks. I'm in the legislature. I couldn't convince them. So whenever here locally exercise our democratic privilege, and we see no result, which, unfortunately, could even be a forerunner or a reason for civil disobedience. And what do you do when you --

(Applause.)

MR. GANDER: I'm not advocating this. I in no way advocate civil disobedience because I don't. But, anyway, the frustration we must understand is real.

And it is not just the usual suspects who come to these meetings and so on. These people represent hundreds and hundreds of other people who are not here today. The problem in the Vermont Yankee has -- one of the frustrations has been the compartmentalization.

You know, the Public Service Board only handles economic consequences. You handle safety. And in the meantime, within the company, maybe up to -- there was a decision, not a decision. They talked about the big three within the company. You pick them off one at a time.

You've got your uprate. You've got your hard cask. You've got your relicensing. Pick them off one at a time. As long as you separate things and put them in a vacuum or, rather, don't put them into context, it's a lot easier to go ahead on that basis.

I feel strongly that from the very beginning, all of these things should have been bundled. All of them should have been bundled and handled in that manner. It's been absolutely maddening.

Now, when you go -- again, I'm off the track for you guys. But when you go to the Public Service Board, we're talking about the economic impact. Public Service Department withheld approval. It actually gave tentative approval until the company came up with $27 million.

Now, to the ordinary public and to me, that just sounds like certificates of public good are for sale. What's the price? Is it 27 million? Is it 50 million? Then we get to the uprate. No. I'm sorry. Hard cask storage last year up in the legislature.

Negotiations are held. And the last final bit of negotiation is what is the price. And the price was 2 million, 2,500,000, something like that, that if the uprate goes through, that will be -- those funds will go for a very useful purpose. They will go for nuclear energy concerns and things like that. Nevertheless, once again, it sounds like a price. Dry cask is for sale.

So you can begin to understand the frustration, but at the same time, let me go to the science side, which I know almost nothing about. We're coming off of decades and decades along a moratorium on the building of nuclear plants. There has been a reason for that. There really has.

And now we have a new energy policy, much of it dedicated to going back into nuclear energy. This policy of this particular administration is very strong now. That's the thing when wanting to drill for a teacup of oil in Enwar. And then we're also going to have this return to nuclear energy. We're returning to nuclear energy not having solved in the slightest effect, any way whatsoever, the problem of nuclear waste.

Now, if you're talking safety, if you're going to look at like the presentation you just had and, you know, this valve goes into that pipe and it comes over here and does this and that's all you're looking at, you're not looking at safety, not in its entirety. Maybe you don't have the purview to look at it in its entirety.

But putting hard cask storage on the banks of a Connecticut river forever -- and it might as well be forever as far as we are concerned -- one estimate, the best estimate, I've heard of how long it would take to get rid of those casks, that's if Yucca Mountain did open -- it's not going to. We all know it's not. They just cut the funding last week.

Congress cut the funding for Yucca Mountain. It's not going to open.

So, even if they find another repository, they get right on it, and you start moving the stuff out, Vermont Yankee probably will be in the line. There's so much of the stuff around it takes a while to get -- you have to line and queue up to when you're going to get the stuff gone. And the estimate, the best estimate, I have heard is with a minimum of 40 years, minimum 40 years.

Okay. Now, this is on the banks of the Connecticut River. My understanding is that in the geological survey -- of course, that comes into your safety, obviously comes into your safety, concerns that we are using data that wouldn't make sense, data from 1960 to 1990, 30-year period, rainfall, this, that, and everything else.

The only problem with it is there hasn't been a single hurricane come up here in that time. We had plenty before. We had 1939. We had Donna in '57 and so on. And in 1927, we had if not the flood of the millennium -- and it wasn't, but it was certainly the flood of the century, which took the major island away, et cetera, and so on.

So, you know, we can't fool around with

this waste. We really can't. And it isn't fair to ask them. It's going to be there anyway, I admit, no matter what you decide, our task is the best method at the present time to store the damn stuff. But to add to it is really I think unconscionable. It's just plain wrong.

(Applause.)

MR. GANDER: Scientists can do wonders, absolutely wonders, and have and also in technology and science, absolutely wonders. They cannot change the half-life of the stuff that is coming out of that place. They can't change the half-life, which is thousands and thousands of years. And we don't know where to put it.

Once in a while way back we thought we would shoot it up into space. That would have been great. Bury it in the ocean. That would have been great. We still don't know where to put it.

So here's little Brattleboro. It's one plant. And here the real context is far broader. The real context is you have an opportunity to really say this isn't making sense. This really I think would be very hard for you. I really do think it would be very hard for you. But you have an opportunity to say this really doesn't make sense in the long run. Partly it's our fault to some degree.

Last point. When we had the Arab boycott in 1973, there was all kinds of investment in alternative energy. And then the oil spigot was turned back on. Energy dried up entirely, no longer competitive, et cetera and so on.

We have wasted 35 years, not entirely wasted, but, on balance, we have really wasted 35 years. Can you imagine where we would be in biomass and various other things, this and that, where we would be if we had concentrated for 35 years on those things? At some point we have to make this an imperative renewable energy, absolutely imperative.

As long as we talk about oil, as long as we talk about nuclear power with its waste problems -- I'm sorry I said it. I will quit in a minute.

One last thing. My understanding -- and I may be wrong. First of all, I really do believe in your integrity utterly. I really do. I believe in the integrity of the engineers and so on at the NRC as far as that is concerned.

My understanding is you have to rely, absolutely rely, in much of the data on what is given to you. You have to assume the accuracy of the data that is given to you. I don't have complete confidence in that. I really don't.

When you have a major self-interest -- and that is Entergy has obviously -- the estimate on what this is going to be worth, the uprate is a minimum of $20 million a year. So if you spend 60, you amortize it in 3 years. And the high estimate is a lot more, lot more, almost a license to coin money. I would believe in profit for the Entergy things so they can go on and do this. Profit is fine, but this is license to steal.

In the public posture, I think Entergy has been extremely clever. I really do. And I admire the way they have handled things. From the first start of the premier point of view, when they first started talking about the uprate originally, they refused to talk about relicensing, "Oh, that's in the future." The future isn't 2012. My God, the 2012 is here today. We all know that. It's right here.

So you talk about the uprate, but we'll get back to that later on. This has been about relicensing since the day they bought the place. You've got to understand that that has to be true. They wouldn't have made the investment unless they were making a bet. In Las Vegas, they call it betting on the come.

Well, the difference is if you're looking at a situation where -- let's take uprate. The NRC it is my understanding has never refused an uprate. We think the odds are pretty good. So you're out there spending your 60 million in there, you know, why does it sound to us, "Well, a decision hasn't been made. We'll get around to a decision and everything else. But in the meantime we've spent $60 million." Holy mackerel. Of course, that isn't a whole lot of money in these days, but at the same time.

Anyway, I plead with you. One last thing. I've got to get out of here. I realize that. I get so wound up on this damn subject. Just one thing, and that is this, that when you're talking about economics and safety, they're absolutely intertwined. They're inexplicably intertwined. They have to be intertwined.

Brattleboro and Windham County doesn't even need to have an accident down here. All you need is an accident within the industry, frankly, in these kinds of computers and so on. And you can take 20 percent off your grab list within 5 years. That's an estimate. obviously. I don't have the science background. But honestly you've got to understand. But to me the major thing is to stop this process of building the piles of waste, which we don't have any idea what to do with them.

And I really do thank you for the privilege of being here.

(Applause.)

CHAIRMAN DENNING: Okay. Now, the next speaker is Joe Hoppenfeld. He's going to be followed by Paul Blanch, Jane Newton, Sally Newton, Ellen Kinney, in that order.

Now, one thing, please. Let's not speak in the audience while the speaker is speaking. No problem with applauses afterwards. We understand that you want to make some statement of support. But please let's not have any speaking while the speaker is talking.

And I'm assuming that it would be your desire to have Mr. Hoppenfeld have a little additional time. Is that true? Yes.

MEMBER WALLIS: Mr. Chairman, are you going to go to 5:30 with no break at all?

CHAIRMAN DENNING: Yes. I think we'll go to 5:30 with no break. And people will get up and --

MEMBER WALLIS: We'll get up and come back?

CHAIRMAN DENNING: Get up and come back.

Would someone object if while we're setting this up perhaps Mr. Blanch came and --

MR. BLANCH: No. I'm Mr. Blanch.

CHAIRMAN DENNING: Oh, you're Paul Blanch. I'm sorry. I forgot. What about Jane Newton? Would she be willing to speak at this time? Do you think we've got it all set?

MS. NEWTON: I'm Jane Newton.

CHAIRMAN DENNING: Hold on just a second. Do you think we've got it or -- in that case, why don't you just have a seat here for a moment? I think we're pretty close to having it set up. Sit that right there for a moment, and I'll introduce you.

MR. HOPPENFELD: My name is Joe Hoppenfeld. I was asked by the coalition to help them. I was asked by the New England Coalition to help them with the evaluation of the NRC SER.

By way of introduction, I have a Ph.D. degree from the University of California at UCLA. I have 40 years of experience in nuclear engineering, including private industry, AEC, DOE, and NRC. I published more than 15 papers in peer-reviewed journals. I own eight to ten patents. I can't remember how many.

The first time I made a presentation

before the ACRS, it was in 1964. And it related to the burn-up of the SNAP 8 reactors. The last time it was in year 2000, and it was related to the steam generator tube rupture and Indian Point 2.

Today I would like to focus my attention on four subjects: steam dryer failure, where I agree with VY that the dryer itself is not a safety component, but the issue is what happens when the dryer fails, what happens to the fragments, where do they go.

There was a book written in the early 1960s. I believe it was entitled *We Almost Lost Detroit*. And it related the story of Fermi or the Fermi nuclear reactor, where small plate downstream got loose because of flow vibrations and found itself in the core, damaged the core, and the reactor never saw the light of day after that.

The next one relates to NPSH margin, which we heard a lot about this morning. The issue here is is the containment going to stay intact following a LOCA accident? Are the pumps going to be adequate? It's not whether they are going to be working or not. They are going to work. Are they going to be working so adequately to remove the heats or the containment will stay intact?

Flow-accelerated corrosion, I don't know why they called it "flow-accelerated corrosion." It's usually called corrosion erosion. And it relates to excessive metal loss, excessive corrosion of critical components. And I will get in a little bit more detail about that. And then the iodine release relates to meeting the 10 CFR 100 and 10 CFR 50 radiation requirements.

Next, please. The theoretical predictions of what is going to happen to that dryer are based on two computer models. One is called the CFD, the other one ACM. These are excellent tools that they use that have been used for maybe over 30 years in the industry.

The problem that we have here is what are the input parameters. The flow of geometry in the dome, in the veins, in the uprisers is very complex. And you have to understand it. You have to describe it to the computer. The computer is not going to give you better than what you put in there.

The only way to do that is to benchmark the code against full-scale experiments. And this hasn't been done. Now, DOI indicated that they will get the information during ascension to power. However, you do not run a LOCA accident when you go up power. What you want to know is what is going to happen to that dryer when the non-loads are generated when a steam line break, for example, breaks outside the containment.

In conclusion, the uncertainty is that two models are not sufficient to rely on it and the ascension to power does not really give you more confidence in the ability of predicting what happens to those vibrations and whether the dryer will fail or not.

Next, please. The recently discovered cracks, 62 cracks, and those that were discovered a year ago are significant. Now, if there are manufactured defects, that's fine. You can forget about that. And that's not that important.

But if those arose as a result of stresses which exceed design stresses, they are very, very significant because now when you increase the vibration of the amplitude of the vibration on that --

MEMBER WALLIS: I think that can be moved so that it fits the screen. It seems to have left from one side to the other. Can't you just --

CHAIRMAN DENNING: There is some incompatibility.

MEMBER WALLIS: Can't you just twist

something and make it --

CHAIRMAN DENNING: I don't think so.

(Laughter.)

MEMBER WALLIS: Can't you just twist? Either move the screen or the projector. Move the screen a little bit or the projector a little bit. Don't fiddle with the electronics. Do it mechanically. It doesn't work. Oh, it's a problem in the computer. It's not the screen.

MR. HOPPENFELD: It's in this device here.

CHAIRMAN DENNING: Incompatibility.

MEMBER WALLIS: I think it was due to operator action myself.

(Laughter.)

MEMBER WALLIS: Well, okay. I guess we have to put up with it, right?

CHAIRMAN DENNING: I think we do.

PARTICIPANT: Change your screen resolution.

MEMBER WALLIS: Now make it smaller.

PARTICIPANT: Yes, that could be it. It could be your screen resolution on that.

MEMBER SIEBER: Go down to that ten percent.

MEMBER WALLIS: Now zoom it up a bit.

MR. HOPPENFELD: We don't have experience with many dryer failures, especially catastrophic failures, but the experience at Quad Cities is a very important data point because they had a similar design. They increased the power by 20 percent, which increased the flow-induced vibrations. And they have experienced a severe fragmentation of the dryer and migration of the fragments to the steam line and to the core, top of the core.

MEMBER WALLIS: How do they get shed down onto the fuel?

MR. HOPPENFELD: I'm sorry?

MEMBER WALLIS: I can imagine them going down on the steam line, but how do they get to the fuel? I'm sorry. You claim that they get to the fuel and --

MR. HOPPENFELD: To the top of the core. They do not -- I didn't say the fuel -- I understand they came down on the top of the core, where the surges were. One or two were found there. Is that --

MEMBER WALLIS: Okay.

CHAIRMAN DENNING: One second. Please go to a mike.

MR. SHADIS: I'm sorry. If I could just interject, the event reports for the Quad Cities incidents related that portions of the steam dryer had fallen on top of the reactor.

MEMBER WALLIS: Okay. Thank you.

MR. SHADIS: Yes.

MR. HOPPENFELD: I misspoke if I said entered the fuel. It came on the top. So you really should look at that thing as a near miss. Now, really the question is, what happens under, say, a LOCA accident like the MSIV, where the loads, the dynamic loads, which could cause excitation of the resonant frequency of the dryer and basically a catastrophic failure, on all of these chunks flying around in the team line? Are you going to have the MSIV when you need it? You've got two of them, but are you going to have them?

That issue is not being addressed. That is an important issue. You can't just forget about these components, even though the dryer is not a safety-related component. They must go somewhere.

MEMBER WALLIS: So what you are worried about is the failure to close the MSIV, rather than blockage of the line?

MR. HOPPENFELD: As a result of the dynamic loads, not your normal condition. Now, under normal condition, you probably increased the probability. You increased the crack propagation. You've got have more.

Potentially they're going to be larger, but the issue is and the question is, what is going to happen on the dynamic loads? And that I have not seen addressed. And it is required to be addressed because it does affect the delta CFE.

Can I have the next slide? I don't believe, although that was viewed as a new phenomena, the failure of Quad Cities, I don't believe that, even -- I don't believe that after two years, our understanding has really significantly been improved or the SER does not reflect an increase in understanding. That statement was made by the industry two or three years ago. And I don't think in the last three years there has been a significant improvement in this area.

Next, please. Now, the requirements are very, very specific. If you are coming and requesting EPU or you are changing the tech specs, that's what you've got to do. And I don't see that in that SER that that was done, that these requirements are met.

I heard a lot of statements about conservatism, and I would like to talk about that a little bit more because maybe it's there, but it's not clear. The calculation doesn't show that. Let me discuss that.

The main uncertainty with whether you are going to have enough pressure of the inlet to the pump, really there are a lot of uncertainties. The whole issue of containment pressure, flow, delta T max in the pool, they're all interrelated.

The equations are all coupled. So you really can't talk about one without talking about the other. And the issue here is what are the uncertainties. There are many. And because of complexity, you have to make a lot of assumptions.

But the one that I'm bothered by the most is where the pressure drops across the screen. The reason for that is because it relates to the interaction between the debris and the sludge and the crud and the corrosion product that you have in the coolant following the LOCA.

There is inconsistency in the report itself, in the SER evaluation. On one side, VY states that the EPU will not increase the source term for the debris. The EPU is not going to detect the amount of debris that you are going to have there. They state that.

On the other part of the report, they

said, "No. We've got another one. We're going to have more because we're going to have flow-induced corrosion. The conductivity is going to check, which means the pH is going to be changing."

You change the pH. You change the chemistry. And you change the mechanism of how the screen or not the screen itself, the fiber degree material that is going to be deposited on that screen, and then plug it up.

If you were sitting here and starting from scratch, you ask yourself, first thing, what kind of part was that? What is the distribution? There is nothing here. They are not even discussing that. But we are here from the NRC, we are here from VY. We have got plenty of conservatism. If there is one, just please show me where it is. It's just not there, just ain't there.

Now, when you see inconsistency within the report and you see that that has been reviewed, now, it's a very valid question how you even go and calculate your delta CDF when you can't even rely on the analysis?

The last subject or I believe it's the last subject -- and here I will be preaching to the choir. That has to do with the iodine release because there are two or three ACRS meetings discussing this issue. And I think that we will be all in agreement here around this table that the NRC, not necessarily the NRC, that we don't understand the mechanism that governs that.

Well, I can say one thing. The fact that you are going to be running at a higher flow rate, you are going to -- the concentration of iodine in the coolant will be lower. It's also true that the concentration in the gap in the fuel is going to be higher or there will be more effusion products.

But what is not true, the fact that I am going to have more efficient products in the fuel and a lower concentration, they cancel each other. And I can go home and sleep well. That's just not true. It doesn't make any sense. There's no correlation between the initial concentration of the coolant of iodine and the amount of appearance that you have or I've looked for it. It's not there. So you can't make that statement.

So what the bottom line of all of this is that -- and this is not a safety issue in the sense like a core mill, but we do have requirements. And they are listed here, 10 CFR 15, which relates to the control room radiation of those is in 10 CFR across the fence and GDC 19, requires you to meet those dust releases.

There is nowhere in this report besides the statement that we meet those. You ask yourself, how can they say they meet those dose releases where they have just started a new generic issue to resolve what the issues are.

So you have a generic GSI. I think it's 197 they just started to rely on these iodine releases, iodine spikes. And I'm not a chemist. So I don't really understand it. I do know I have seen the data and I didn't bring the curve, but you can -- I guess everybody around the table is familiar with it. I'm showing the order of magnitude or more increase in the iodine release as you lower the initial concentration. So if they lower the initial concentration, they're going to have increase.

In addition to this, I didn't see in the SER any references to increasing -- to using iodine, concurrent iodine. By doing that six seconds before that MSIV shut down, you're going to have a big pressure change. I haven't seen anything there.

Now, if you have orders of magnitude of safety there between what the -- I believe it's like 5 rem from the control room and I think it's 25 across the fence. I don't remember the number, but if you have plenty of room there, well, that's fine. And I don't know whether it's from rewire, but I've seen it on similar reactors because it depends on the weather around here.

If you have plenty of leeway, then it's fine. You've got plenty of safety. But I think they're very, very close to the limit as it is. So when you neglect all of these mechanisms, there's a lot of uncertainty in there. Now, you know, it's up to the local cop who lets you drive 65 miles an hour. That's fine. But that's what this is.

To summarize, the main issue is the dryer.

CHAIRMAN DENNING: Thank you very much, Dr. Hoppenfeld.

(Applause.)

CHAIRMAN DENNING: I would like to have Jane Newton go next if she'll move up into this area right here.

Did you leave us a copy of your presentation or you can mail it to us? We've got it. I'm sorry.

MR. NEWTON: I think this is going to be very different because I am going to talk mostly about fears and the people who live around here. I'm going to speak for myself first. And then I am going to speak for my daughter, Sally, who can't be here because she is a school teacher and she couldn't come.

I have to read it because I am not very good at this. My name is Jane Newton, and I live in South Londonderry, Vermont. Because what is happening between the NRC and Entergy Corporation threatens the very lives of those who live within hundreds of miles of Vermont Yankee, we feel betrayed by the shameless, indeed criminal behavior of our governor, our state legislature, the corporate-owned federal government, and you, the members of the NRC, the only people actually charged with our safety, who, with unbelievable irony, are in the process of forsaking us. The NRC, as we all knew but still had a trace of hope for, is just one more benefactor of corporate crime bent on selling us all out by placing corporate profits before the possibility of unthinkable suffering and death in this case some form of radiation.

A Chernobyl-type accident, which will not be an accident if this uprate goes forward, will become not just a vague possibility but a nightmare that is likely to happen.

So we are all in a death grip of corporate crime, be it in war and militarism and the expectation of the corps over the world in the pollution of our environment, to the point of making it uninhabitable and to the threat of a nuclear disaster.

The threat of nuclear disaster comes currently in the form of nuclear weapons, in the groundwater, the air, the sea, the surface of the earth, and even in space, partly as a byproduct of nuclear power, depleted uranium, which is deposited by the tons whenever the U.S. has been at war since 1991, causing birth defects, cancers, and deaths by the thousands in soldiers and civilians, especially in the world's children, and partly from nuclear power plants.

We all know that these plants produce waste that is turning the world into a nuclear dump since nobody knows what to do with it, provide a handy target for terrorists, and present the unspeakable possibility of an accident or a meltdown, which grows astronomically when all of those plants are asked to do more than they were built to do.

This heartbreaking situation has us here before you full of hopelessness and fear for our children, begging you who are supposed to be keeping us safe but are, instead, violating or trust to please think again before you allow Entergy to go ahead with this uprate. We cry out with tears, with our hearts, with our minds, and with our despair, pleading with you to decipher life, not the end of life as we know it.

This is from my daughter, Sally. My name is Sally Newton, and I live in West Townsend, Vermont. For the last couple of years, I have been hopeful that the Public Service Board, the governor, the legislature of our state, and the NRC would listen to the safety concerns of the people who live in the vicinity of Vermont Yankee and heed the advice of many of the experts who have stated that the 20 percent uprate of the old nuclear plant is a bad idea.

Now it seems that, in spite of the risk of this proposed uprate to the people and the environment, there are many problems that Vermont Yankee has had these past few years through lack of a solution to the waste storage problem. And in spite of the thousands of signatures collected calling for an independent safety assessment, our requests are being ignored. And these various governing bodies are one by one caving into the demands of Entergy Corporation. My heart sank as I realized our safety is less of a concern than the topics of the corporation.

I teach at a very small elementary school in Windham, Vermont, 30 miles north of Vermont Yankee. I wonder how we will know if something goes wrong at Vermont Yankee and what we should do as we have no evacuation plan.

Do we take the kids to Bellows Falls or should we take them some other place, such as Canada? How will parents know where their children are? How will I solve the dilemma of whether I should save other people's children or go and find my own son, who is in another school? What if something happens at night and we are all sleeping with radios and TVs off? How will we know? How can the regulating body in charge of so many people's safety allow this kind of confusion?

Do you really expect us to believe that the people outside the designated ten-mile radius will be safe if there is an accident at Vermont Yankee? On top of all of this, most people in my area are not educated about the dangers or the effects of radiation or what to do if an accident happens.

It is completely negligent of the NRC to approve of a power uprate in an aging plant without at least requiring an independent safety assessment and a working evacuation plan for at least 50 miles around the plant.

Schools, hospitals, and homes should all have emergency notification systems. And people should be educated, not left in the dark, about the dangers of radiation.

Please do not just write our concerns off. Think of what you would want if your families lived in this area and your children attended our schools. Please require an authentic independent safety assessment and an expanded and approved evacuation plan. Please be responsible to the people who live here. Do not sacrifice our safety for the profits of Entergy Corporation.

Thank you.

(Applause.)

CHAIRMAN DENNING: Thank you.

The next speaker will be Paul Blanch, followed by Ellen Kinney, Tom McLean, Pete Newton, and Sally Shaw.

MR. BLANCH: Thank you, Mr. Chairman. Thank you, ACRS members and members of the public, to take time out to listen to this long session today and yesterday.

Again, my name is Paul Blanch. I reside

in West Hartford, Connecticut. And I have about 40 years of nuclear experience, both with the utilities and with the Navy.

As far as this proceeding goes, I have no political or financial interests. And I am not being compensated whatsoever for any of my efforts related to the Vermont Yankee efforts.

Our first speaker yesterday was a former governor of Vermont. And he stated that the EPU should be approved "if all regulatory requirements are met." I know I'm going to get at this point some of the members of the public, but I don't disagree with that statement "if all regulatory requirements are met."

I have been concerned about the EPU primarily related to the containment overpressure and the interdependence of the barriers, meaning the failure of one barrier could result in the possible failure of another barrier.

I was very troubled and very surprised by Mr. Hobbs' statement this morning that there already is an interdependence of the barriers. He clearly stated -- and I believe I heard this correctly -- that the failure of the Torus -- and I assume he is talking about a catastrophic failure of the Torus -- will result in core damage in disabling some of the safety instruments, which would result in -- well, the failure of the Torus would result in failure of the ECCS, which would result in the failure of the fuel or fuel meltdown.

Now, either Mr. Hobbs does not understand the design basis of Vermont Yankee -- and he is the engineering supervisor. And I believe that that event -- I could be wrong, but catastrophic failure of the Torus I believe is outside of the design basis and is not considered.

If he believes it is inside the design basis, he is misinformed. Either he is misinformed or he was trying to mislead this group and members of the general public by trying to convince everyone that we already have this interdependence of the independent barriers that provide the defense in depth. That is extremely troubling to me.

I have reviewed the ACRS' mission. And I believe the ACRS reviews certain changes and license amendments and makes recommendations to the Commission. When I say "the Commission," I'm talking the five commissioners.

I have reviewed some of the ACRS letters and typically find words along the lines -- I'll paraphrase it -- the ACRs is satisfied that the licensee will comply with all applicable regulations. Those are not the exact words but words along those lines whenever they are commenting on a proposed change, be it life extension, power upgrades, other license changes that the ACRS elects to review. That's not their sole responsibility. I believe that it is one of their responsibilities.

So how does the ACRS determine that this plant is in compliance with the applicable regulations? The Atomic Energy Act and the Energy Reorganization Act -- and, again, I'm going to paraphrase this -- make the statement along the lines that adequate protection to the public is provided if the licensee complies with the regulations. Those are not the exact words. I do have the exact words available, but it's pretty much the thought.

We have numerous indications that neither the licensee nor the NRC is fully cognizant of the compliance with the regulations. We brought up an issue. And we have written to Senators Leahy and Jeffers about the general design criteria.

The general design criteria were developed back in the mid '60s. I look at them as sort of the Ten Commandments. How do you design a power plant?

And the other and then the old regulations and reg guides and bulletins, orders, and all the other documents are interpretations of those commandments, such as one of the commandments "Thou shalt not kill."

Well, how does that apply in wartime? And there is always the area of abortion. These things are very vague and need clarifications. And other regulations interpret them and support it by various other supporting documents produced by the NRC.

When we reviewed this initial application and the updated final safety analysis report, we found that there was no commitment to the general design criteria in any of the licensing documents. In fact, in appendix F to the updated final safety analysis report, Vermont Yankee clearly made the statement that in this appendix, these are for historical purposes only.

About a year and a half ago, Mr. Arnold Gunderson and I asked for some clarification. So we filed a 2.206 because it really, really was not clear what the applicable general design criteria were.

And part of that 2.206 is up on the screen. And it requests basically that the NRC seek from Vermont Yankee clear and unambiguous definition of the general design criteria applicable to Vermont Yankee and how the facility's design conforms or deviates from the 70 draft or 62 final -- actually, 55 final.

The 2.206 petition was rejected after a year. And it's really not clear to any of us -- when I say "us," I mean the NRC and the licensee -- exactly what regulatory requirements are applicable.

To give you an example, the NRC in their safety evaluation report mentions 64 general design criteria, final general design criteria. And the NRC isn't aware that there are only 55 of these general design criteria.

And then the safety evaluation report, the draft safety evaluation report, goes on to talk about compliance with the 70 draft design criteria.

Well, I went through a computer search of the SER, and they only mention 48 out of 70 draft criteria, how the other 22 got dropped -- and, believe me, those other 22 are not addressed in any of the other documents the NRC claims they are. The general design criteria is an example of compliance with regulations.

There are many other examples. If one goes through ADAMS at the NRC Web site, you will find that there are literally hundreds of exemptions to various regulatory requirements, including appendix J to 10 CFR 50, which I believe has to do with containment leak testing; appendix R, which is a fire prevention.

There are literally hundreds of exemptions that on their own may have been evaluation in isolation, but combined, we don't know the combined effect of all of these deviations from the regulations.

The ACRS contemplates a letter to the Commission. However, I believe the ACRS must assure itself that Vermont Yankee poses no undue risk to the public. In order to make that call, I believe the ACRS needs assurance that VY is in compliance with NRC regulations and identify all regulatory noncompliance.

It is the decision of the ACRS as to how to accomplish this clarification, whether it be an independent safety assessment, a matrix produced by the NRC, or some other vehicle that the ACRS can assure themselves that this plant is in compliance with the regulations and, therefore, provides reasonable assurance of public safety. Further verification of compliance with the NRC regulation, there is no assurance that the public will be adequately protected.

I would be more than happy to respond to any questions the Committee may have. Thank you.

MEMBER WALLIS: I had a question for you. It's a clarification. You started out giving me the impression that the GDCs were not referred to at all. And then later on you gave a list which seemed to indicate that most of them were but there may be some still missing. Which of those is it?

And if you know which ones are missing, maybe you could let us know so we know more specifically which ones you're concerned about.

MR. BLANCH: Yes. I have actually produced a list. In fact, I could give the Committee the draft 70 criteria, which are not easy to find, by the way. And I have them circled as to which ones have not been addressed.

As far as addressing the general design criteria, we look at the safety evaluation report, the draft one, that was just recently issued. That is only the applicability of the draft general design criteria to this change. It's not the general applicability.

One of the draft general design criteria -- I believe it's number 22 -- is single failure.

That is not addressed. And Ms. Hobbs this morning was talking about a single failure that could take out two of our three primary barriers protecting the public. That is very troublesome to me.

I think the ACRS really needs to determine the degree of compliance and, therefore, safety of the Vermont Yankee plant, with or without the uprate.

MEMBER WALLIS: If we're talking about an uprate, it might be that some of these criteria are not relevant to the uprate in some way and that the changes brought about by the uprate make no difference or something I don't know yet until I have looked at it.

MR. BLANCH: Well --

MEMBER WALLIS: But we're not talking about Vermont Yankee in total. We're talking about an uprate.

MR. BLANCH: Well, I think if I were adding 20 percent to a building out in California, I would want to make sure that if I were adding 2 floors to a 10-story building, I would want to make sure that that building before I put the 2 stories complies with today's seismic requirements. That's my point.

(Applause.)

MEMBER KRESS: Let me put the onus back on you. How would you advise the ACRS to assure itself that the Vermont Yankee is in compliance with the regulations?

MR. BLANCH: I'm sorry. My --

MEMBER KRESS: How would you tell the ACRS to go about assuring itself that the Vermont Yankee is in compliance with all the regulations?

MR. BLANCH: Well, again, it's the ACRS' decision on how they determine that there is reasonable compliance with the regulations. The ACRS could write or direct the Commission that the staff evaluate Vermont Yankee for its compliance with the regulations and identify where it complies and where it deviates.

The ACRS could recommend to the Commission that they have some type of team in there and they go in, rather than an engineering inspection that had no acceptance criteria, to have a checklist. How do you meet the single failure criteria? How do you meet criterion 64, which is effluent rad monitoring, and, again, containment penetrations, fuel clad temperature? They're all in the design criteria. It's not an easy task. And this is the same request the Vermont state legislature made of the NRC, and that was rejected.

And I will not be confident that this plant can operate safely unless someone can reasonably demonstrate to me that it is in compliance, hopefully with today's regulations, but they don't want to go there.

CHAIRMAN DENNING: Thank you. Well, I think we understand.

MEMBER WALLIS: I guess we're going to stop now? That's fine.

CHAIRMAN DENNING: What's that?

MEMBER WALLIS: We can stop if you like.

CHAIRMAN DENNING: Yes. I think so. There are a lot of people still who would like to.

Thank you very much.

MR. BLANCH: Thank you very much for your time.

(Applause.)

CHAIRMAN DENNING: Ellen Kinney is next, followed by Tom McLean, Pete Newton, Sally Shaw, Arthur Pattey. Tom McLean is next, followed by Pete Newton, Sally Shaw. Is Tom McLean there?

(No response.)

CHAIRMAN DENNING: Is Sally Shaw?

MS. SHAW: Yes.

CHAIRMAN DENNING: Okay. And that will be followed by Arthur Pattey and then Ed Anthes, I believe is the name.

MS. SHAW: Hello. My name is Sally Shaw. I am a member of the Gail Montague Regional School District Committee. I am speaking here on my own behalf, although the school committee has written letters to the Public Service Board and to the NRC opposing the uprate.

My basic comment on the recent SER is going to be delivered in code to show you what it felt like trying to read it. NRC's SEs and QA of RA is based on IEBGIDSSLATSsE's and QCSFAS, not on BATAILA or the PP. I give it an F.

(Applause.)

MS. SHAW: Now, if you would like to know what that means, I will translate. NRC's so-called safety evaluation and timid assertion of reasonable assurance is based on inconsistent evidence, bureaucratic gymnastics, industry deregulation, self-serving license amendments, technical specification exemptions, and theoretical calculations substituted for actual surveillance and monitoring whenever and wherever it suits the industry.

It is not based on best available practices, actual inspections, legitimate analyses, or the precautionary principles. I give it an F.

(Applause.)

MS. SHAW: I do have some examples to substantiate my opinions. In summary, I believe that the NRC removes design margins and technical specifications. And then they find no risk based on their own lack of standards.

This is not oversight. It is overlooking the obvious. Examples: NRC is grandfathering design and safety criteria for a plant nearing its license termination that is increasing power over its as-designed capacity. This is not the reasonable assurance of public health and safety.

We request the ACRS to send the uprate application back to the drawing board and require Vermont Yankee Nuclear Power Station to meet current design and safety standards if they wish to restart and operate at 100 percent power with the highly enriched fuel which they're loading now or if they wish to operate at 120 percent of what the plant was designed to run at.

In the SE on page 3, the NRC staff wrote that "Continuing improvements in analytical techniques have resulted in significant increases in the design and operating margins between calculated safety analysis and the current plant licensing."

My take on that is that if you look at what has been going on in the Federal Register for the past few years, alarm license amendments, elimination of surveillance requirements, and changes in technical specs have been dribbling out in the Federal Register for the past two years.

We think that what the NRC calls improvements in analytical techniques are actually relaxation of standards, deregulation, or a shift toward industry self-regulation.

What impact do changes such as the following and to do accountability have on the bottom line analysis? Here are some of the things that have been changed: elimination of annual worker occupational radiation exposure reporting requirements, increases in allowable mainstream isolation valve leakage rates, permanent exemptions from ILR tests, exemption from the schedule 2005 integrated primary containment leak rate testing.

Do these changes allow Entergy to increase their operating margin? But at what cost to workers and the public? How has NRC adjusted its standards for radiation exposure in effluent releases, leakage allowances in light of the National Academy of

Sciences study. We are seven, which definitely states that there is no safe level of radiation exposure, whether to average man, woman, child, elder, immunocompromised, or Charles Atlas.

How has or will the NRC respond to this? How can the NRC justify grandfathering a lengthy old nuke using a weaker design criteria than is currently required for new reactors? What are the best practices precautionary principles in light of this loud warning from National Academy of Science scientists?

We request that the ACRS call a halt to all uprates and relicensing until the NRC revises allowable radiation exposure limits in light of the NAS recommendations and until they conduct an independent safety analysis on Vermont Yankee as was done at Maine Yankee.

The issuance -- this is on page 7 of the SE. The issuance of the license amendments will not be amicable to the common defense and security or to the health and safety of the public. Any increase in spent fuel, inside or outside of the spent fuel pool, is amicable to the common defense and security and to the health and safety of the public.

Not requiring Entergy to report annual

occupational radiation exposure for their workers is inimicable to worker health and safety and that of their families. Increasing allowable mainstream line leakage rates and eliminating the 2005 scheduled integrated primary containment leak rate testing is inimicable to reasonable assurance of no added risk to the public. Why was this allowed?

On page 8 of the SE, the September 2004 engineering inspection, in selecting samples for review, the engineering inspection team focused on those components and operator actions that contribute the greatest risk to an accident that could involve damage to the reactor coolant.

As you know, the inspection team found eight problems or ten, depending on whether you could the unresolved issue and the one that had been already relegated to corrective actions, within a carefully selected set of high-risk operator actions and components. That represents 18 to 22 percent of the items that they looked at which were dysfunctional.

If these high-risk actions and components, those to which the industry and the NRC should be paying closest attention, are not being managed properly, what does that imply about the balance of plant operations and components?

We hope that the engineering inspection was inadequate to provide reasonable assurance that the uprate is not amicable to the common defense and security and to the health and safety of the public. We beg you to require an independent safety assessment as performed at Maine Yankee. Our children deserve no less protection than Maine's children.

And I would also like to point out that at Three Mile Island, the mechanical failure that precipitated operator mistakes was not a low-margin, high-risk component.

The Vermont Department of Public Service -- I am sorry that they have left; I guess they don't want to hear from the public they are supposed to serve -- does not speak for the people of Vermont or for us downwinders in Massachusetts and New Hampshire.

And having signed a memorandum of understanding with Entergy, they can't even common on the 62 steam dryer cracks. If they can't comment on the consequences of dangerous conditions with the reactor, they should resign. I know that doesn't involve you, ACRS, but they stood up and volunteered their opinion when they were not asked. So I'm volunteering mine.

I also want to point out that two of nine operator teams could not shut down the reactor in a January 2004 NRC inspection. This is documented on the ADAMS database.

The NRC gave this a green rating because it was a simulation, not an actual accident, and because "less than one-third of the operator teams failed to scram." That is not reassuring, and that is not reasonable.

The NRC claims that the operator response time to shut the plant down from an alternate panel was evaluated for uprate conditions. The September 2004 engineering assessment rejected operator response time, only for a 15 percent uprate, not for a 20 percent uprate, as requested by the licensee.

At least in my copy of that inspection report, the table provided showed the difference between current operating conditions and the 15 percent uprate.

So all of this talk about 21.3 minutes and the 18-second margin should be revised. We request that the actual retested operator margin of error be reported to the public in terms of the 20 percent uprate, not in terms of the 15 percent uprate the inspectors analyzed before ACRS signs off on it.

The surveillance date from the Susquehanna unit 1 -- this is on page 15 of the SE -- "The surveillance date from the Susquehanna unit 1 will be utilized to monitor the impact of neutron radiation on the Vermont Yankee Nuclear Power Station outline materials." This is in reference to testing the reactor for embrittlement.

The NRC is allowing data shared between nuclear plants to substitute for actual surveillance testing and monitoring of Vermont Yankee's embrittlement.

In keeping with Entergy's record of using flawed projections, fuzzy calculations, and peculiar math, rather than actual instrument readings, to determine, for example, radiation exposure, they prefer to use test data from another reactor in Pennsylvania as a proxy for the Vermont Yankee reactor vessel material integrity while Vermont Yankee's untested capsules, originally part of the licensee's plant-specific surveillance program, having received significant amounts of neutron bombardment, will remain in place. That's a quote from the SE, that latter. This does not provide the public with any sort of reasonable assurance of anything.

The use of an alternate assessment is only allowable if the reactor has an adequate dosimetry program. How is adequate defined? What I know about Entergy's calculation of doses follows. Entergy uses one roentgen is equal to .71 rem, instead of the standard one roentgen equals one rem. Thus, they have a 29 percent discount on their calculations.

They no longer have to report annual work occupational exposure. They haven't adjusted allowable radiation limits based on the BEIR number 7 report of the National Academy of Sciences. So how can NRC staff call that an adequate dosimetry program?

We request the ACRS to require that Entergy pull out at least one test capsule from the Vermont Yankee reactor vessel and compare it to the neutron bombardment levels of a similarly located Susquehanna capsule before making the assumption that the two are interchangeable.

One has to wonder if NRC staff figures that if you replace actual monitoring and testing with alternate methods of projection and calculation, Entergy can then pass the test. It appears to the public that they seem to be more interested in protecting corporate profits than public health and safety. We need to build trust here, and there is a way to do that. And that is to conduct an independent safety assessment.

(Applause.)

MS. SHAW: One more point regarding stress corrosion cracking. This draft SE report was released before Entergy revealed the nugget that there are not 14 cracks in the steam dryer but 62.

The NRC staff assessment that the biggest crack would only increased from 12 inches to 13.32 and not to 15, so it was, therefore, safe is not reasonable assurance of steam dryer integrity.

In light of new revelations about the extent of steam dryer defects, we request the ACRS to require Entergy to pull the aged, cracked steam dryer and replace it with a new one before uprating, before ascension testing, before operating with super hot fuel.

Before even starting, they must pull it out and either subject it to radiography and dye penetrant testing to determine the actual extent and depth of the cracks or replace it. I understand that reactors in France test their steam dryers in this way every time they refuel.

That's all I have to say.

(Applause.)

CHAIRMAN DENNING: Thank you very much.

The next presenter is -- we'll let Mr.

Newton go next, Pete Newton. And he will be followed by Arthur Pattey and then Ed Anthes.

MR. NEWTON: My name is Pete Newton from Windham, Vermont. And I am representing myself, my parents, my wife, and my two children. Thanks for your attention.

History has shown that government regulators can be compromised by the close involvements with the industries that they should regulate. Because of the enormous consequences of failure, as regulators of the nuclear industry, you have a special responsibility to remain impartial and to rule in the public interest.

Because of the apparent contradiction of changing design capacities without useful independent safety assessment or a long-term waste storage plan, the proposed uprate can at best be considered risky, short-sided, and of benefit only to the plant owners.

Please say no to uprate. Thank you.

(Applause.)

CHAIRMAN DENNING: The next speaker will be Arthur Pattey.

MR. PATTEY: My name is Arthur Pattey, pronounced like the race car driver. I live in Guilford. Thank you for taking the time to listen to me today. I sincerely hope that you hear what I and my fellow citizens are saying.

I am not an expert on nuclear energy. We have heard from them. I was amazed at how much I did understand. But, quite frankly, I am not reassured.

I am not affiliated with any group of organization. I am a simple carpenter. Because of a minor back injury, I am not out earning my living today. I have the time to stand and listen to these two days of testimony. I probably should be out looking for a good set of snow treads, but I believe safe driving this winter and in the winters to come has a lot to do with what goes on here today.

I am nervous speaking in front of a group of people, which is why I am reading this. The only other times I would be speaking in front of the public is as an amateur actor in local theatricals. I thank Vermont Yankee for their generous sponsorship of the arts in Windham County and their other fine corporate citizenship.

But I am not here speaking as an actor today. And the clowns were yesterday. I'm speaking for myself, my family, and I believe for many like-minded friends and neighbors. I'm speaking from my heart.

Yesterday there was some discussion of what a safe distance from a nuclear power plant is. Ten miles? Fifty miles? I would venture to guess that my home in Guilford is within the five-mile range.

Vermont ain't flat. And for that, we thank God. Because of Huckel Hill, you can stand in my garden, fish the trout stream if you like. It's not posted. And you would never know that you were in a danger -- excuse me -- an evacuation zone.

In nice weather, we have guests who have said, "Hey, if it weren't for I-91 in your back yard, this would be heaven." Well, I know better. I live there during the Ski-Doo season.

I also know better because I get the calendar. It's a good calendar. It's got nice pictures. There's lots of space on the dates to write down important appointments, like a baked bean supper at the Grange, Ally's birthday, all school sing, and missed appointments -- glad I missed that one -- oh, and safety hearing on Vermont Yankee.

I use these calendars every year. And every year I read the emergency instructions, at least most of the 15 pages. It always scares the hell out of me.

If we were told to evacuate, even under the best of circumstances, it would be a mess. And if it happened on a night of flooding, like we had last month, a lot of my neighbors up on Slate Rock Road, some of them VY employees, wouldn't have a road to evacuate on. Sorry, neighbor. We don't have any more room in this car.

This nasty scenario is assuming that we did get the evacuation notice. We don't have sirens in Guilford. If it's real quiet, no trucks on the highway, we might be able to hear one from Bernardston or Northfield.

We do have a tone alert radio. Many times I've breathed a great sigh of relief to hear "This was only a test" or "The flood watch in Renselear County has been canceled."

The radio isn't working right now. It needs a battery. I filled out the questionnaire that Vermont Yankee sent me and sent in a request for a new one and a manual on how to program the thing. I'm still waiting. Until I get a new battery and the instruction booklet, we will have to rely on option number 3, route alerting.

I do have great faith and great admiration for our local emergency personnel. I cannot say the same about the present owners of this facility.

This is the first time I've spoken publicly about this issue, but I am not new to the discussion. I was a school kid here in Brattleboro when plans were laid for building the plant.

I remember the 67 blackouts. And, to the best of my recollection, it was about two hours before we had the lights on back in Brattleboro, where some people were stuck in elevators in New York for eight to ten hours.

My dad and a friend were doing some work in the basement. At first, they thought they had caused it. "We knocked out the whole neighborhood."

When my father and I were not arguing about the length of my hair, we had long, if uninformed, discussions about this issue. As I remember, one of the big arguments against building the plant in the first place was how much it was going to raise the temperature of the Connecticut River.

None of us had heard of Three Mile Island or Chernobyl. We hadn't heard the fighter jets scream over this valley, as we did two nights after 9/11. Well, none of us were sleeping too well that night anyhow.

My dad was the shop teacher here in

Brattleboro, 35 years working with young teenagers and power tools and no major accidents. He knew something about safety.

One of his repeated lessons on the topics was that you never took a tool or machine, whether it was as simple as a handsaw or as complex as a boiling water nuclear reactor, and tried to make it do something it was not designed for or push it beyond its exceededness.

(Applause.)

MR. PATTEY: Chances are you will only break it. He's gone now, but I know he would agree with me when I say to try and run this machine called Entergy Vermont Yankee 20 percent harder when it is already approaching the end of its designated life span is just plain stupid.

These days I continue to have discussions, hopefully more informed, with my 11-year-old daughter about the safety of the plant. When she asked me a couple of years ago on the way to the skating rink on a first Saturday morning of the month at noon what the siren we were driving past on Western Avenue was for, I did my best to explain. She then asked me, "What would happen if there were a real accident at the same time as the test?" I didn't have an answer for that.

I do congratulate Vermont Yankee on its years of operational efficiency and safety. I cannot speak, as others have, to the dangers of low-level radioactive emissions.

I can only attest to the fact that the unusual events alert -- and I'm not sure if we've even ever had an actual site emergency or were those just tests, but I can say that none of this has been beneficial to my mental health.

I forgive Vermont Yankee for the statements about electricity being too cheap to need them. I don't think any of us believe them. I do ask how increasing output and possibly running the plant longer will deal with the unsolved problem of waste disposal.

I personally believe -- and I know some of my friends and family will disagree on this -- that given the past record of Vermont Yankee, the benefits do outweigh the risks of running this plant to its original capacity and life expectancy. I'm not saying shut the plant down, but let's not screw it up now. Maybe if I were a stockholder in Entergy and lived a lot further away, I would say, "What the heck? Let's go for it."

I'm a simple carpenter hoping that my back is better soon and I can get back to work, pay for some new snow treads, go on living my life with my family, my friends, my neighbors in this community around Vermont Yankee.

I can only repeat what I said earlier. The idea of an uprate of this facility is just plain stupid. I ask, I implore, I beg of you gentlemen of the NRC Advisory Committee here today to do whatever it is within your power to deny this request from Entergy to Vermont Yankee.

Thank you.

(Applause.)

CHAIRMAN DENNING: Thank you.

The next person is Ed Anthes, followed by Celia West, Ray Shadis, and Paul Bousquet.

MR. ANTHES: Good afternoon. Thank you for taking comments from the public. I appreciated the comment from one of you yesterday that you're not restricted, you can look at everything you want as regards to the uprate request. And we're counting on you to do that.

I'm going to talk about some of the emergency planning zone issues and margins of safety. The difficulty that we have is that Entergy Nuclear is shaving margins at every possible point. And I'll talk about some of those.

It's appropriate that we're where at the Quality Inn. We're about nine miles from Entergy Nuclear, Vermont Yankee here. When they came to Vermont, Entergy decided they would set up a limited liability corporation. And they picked those words "Entergy Nuclear, Vermont Yankee," E-N-V-Y. It seemed to be a little while before they realized they had named themselves after one of the seven deadly sins. So they don't use the word "Nuclear" any more.

Anyway, where we are is right at the limits of the siren notification are in the emergency planning zone. Of the six towns in Vermont within ten miles of the reactor, only portions of two towns have siren coverage. According to maps in the Brattleboro emergency plan, we're right at the edge of that area, but we may not hear if a siren goes off.

Tone alert radio is a principal means of notifying people in the ETZ of an emergency situation, but most people and families don't have them.

Last year Entergy Nuclear was cited for losing control of the tone alert system, having no record of who does or does not have a radio. Entergy Nuclear could have mailed a radio to each family and business in the ten-mile zone but chose not to.

Instead of sending a radio, they sent a letter. When they distributed out about 1,300 radios, the NRC was satisfied.

So I asked at the front desk if they have a tone alert radio to notify guests in case of an accident at Vermont Yankee. They don't. Most of you are visitors to Vermont. So if a bunch of the Entergy guys jump up and head to the door, drive north.

If implemented, this 20 percent power boost will take ENVY up to the limit or past it for off site radiation exposure. Vermont has a 20 millirem standard. Measurements by the Vermont Department of Health one year ago showed that ENVY exceeded the standard in the fourth quarter 2004 and, in fact, pushed the margin on the 25 millirem federal standard. Not surprisingly, ENVY disputes the Department of Health data, and negotiations have been ongoing.

VY wants to push the limits on safety margins with the NPSH credit. In area after area, ENVY is shaving margins in a grand experiment to see if they can squeeze more schemes, more electricity, more dollars from this 33-year-old reactor.

The Vermont's Public Service Board is concerned about this and the reliability of ENVY. And in the final orders giving conditional approval for the uprate, it stated specific criteria for an inspection.

Public Service Board's August 16, 12, the final order, appendix D, the assessment would be a vertical site review of two safety-related systems and two maintenance rule non-safety systems affected by the uprate.

The level of effort necessary for this work has been described to us in testimony as requiring about four experts for about four weeks. This will provide a valuable check on reliability of the systems that are reviewed and allow for correction of any problems.

To date the Public Service Board has reserved judgment on whether these meet the nuclear requirements of their order, and they're really waiting to hear what you have to say on that.

The public does not believe that the inspection done was adequate. It took repeated requests from the Vermont Public Service Board to initiate the inspection. And when it was done, well, I was interested that this one got to a number of you as well. This jumped out at me. And as a long-time amateur in this, it was gratifying to see that it was important to you as well.

It's the safe shutdown analysis, the reactor core isolation cooling time estimates. The time line is in 1999 they determined that it would take 25.3 minutes to boil away the water and expose the core. And then it would take 15 minutes to start up the RCIC.

In 2001, the Operations Department determined at that time 15 minutes was wrong. It was actually 19.3 minutes. But they neglected to tell the Engineering Department. So the Engineering Department submitted their request for extended power uprates using the old figure. They didn't know that the Ops Department had increased the time estimate by 29 percent.

In 2004, the NRC determined the time to be 21 minutes; actually, 40 percent over what was used in the estimate. And it wasn't discovered, of course, as we have had thorough testimony today that that wasn't discovered until ENVY was forced to run a drill on it.

ENVY estimated it would take 21.3 minutes to uncover the radioactive core. I really appreciated the skepticism I heard from you in questions about what is adequate margin. What is the risk that is acceptable? What does that .3 mean to us who live here and to you are just putting your stamp on approval on this request?

If there's a question, though, what else has been miscalculated because of erroneous assumption? What other errors have been mapped? The Public Service Board, correctly identifying the extraordinary nature of the 20 percent power boost, wanted more than the standard inspections.

We have already experienced an unplanned shutdown at Vermont Yankee because of the uprate: two fires in 2005, the transformer fire and the simultaneous hydrogen leak fire. ENVY testified that it wasn't the uprate that caused the fires but poor maintenance, both before and after they took over.

What happened? Well, following the refueling outage in 2004, the air speed cooling the transformer was more than doubled, cracked metal slapped in this new wind tunnel breeze eventually sparking and shorting, igniting a pool of oil laying on top of it, and causing a fire that Brattleboro's fire chief described as flames leaping 30 feet into the area. The Public Service Department, electric companies, and ENVY are negotiating who will pay what for the resulting service disruption. But there's really little doubt that with the changes made for the uprate at the 2004 refueling, that increased air flow starting the chain of events that shut down the reactor.

Some areas of concern have been identified as potential problems because they have broken at other EPU reactors. While we don't know what will be the next thing to break, we can be sure there will be something. We don't know how these problems will be or the costs or if excess radiation will be released.

This morning and into the afternoon, Russ Kulas, who is a member, an engineer and member of the Vermont State Nuclear Advisory Panel, was able to be here for the proceedings. Last month at the Nuclear Advisory Panel meeting, he stated as an engineer, he was amazed that the NRC didn't include three points of performance below the uprated levels and suggested that ENVY be forecast at .75, .85, .95 as well as the 1.05, 1.10, and 1.15 that they agreed to do so that you and the staff can see a progression as it goes along. And I request that you consider putting that in your recommendations.

Here in this room we have seen here those people who have enough time and interest to sit through this meeting. The group that I work with as a volunteer, Nuclear-Free Vermont by 2012, has worked to provide opportunities to speak out for people in the towns of Windham County who can't come out time after time to regulatory meetings.

In Vermont, we have a strong tradition of town meetings. Each month townspeople all over Vermont meet to discuss town and school budgets and the issues of the day and to vote on these things. Over several years, local towns have voted a town meeting day on Vermont Yankee issues.

As Senator Gander remarked earlier, the towns in the county have overwhelmingly said that when 2012 comes, we have had enough. It's time, then, to shut down Vermont Yankee.

It's obvious that for Vermont Yankee EPU and on site dry cask storage are steps to make the continued running after 2012 more profitable, but it's likewise obvious that the operation of ENVY after 2012 is contrary to the wishes of the majority of people in the ETZ and in Windham County.

We have been through six years of hearings and meetings, Public Service Board hearings on the sale of Vermont Yankee, regional and state meetings on dry cask waste storage, meetings on the condition of the river, and on the unannounced off-site dumping of excavation dirt from a power uprate building project to be done without Public Service Board approval.

In some ways, it's surprising that anyone at all comes out for these meetings anymore. But at every meeting, new people come out to voice their opposition.

I don't go along with the designation for NRC that nobody really cares. By the questions that you have asked and the issues that you have asked for more analysis, I believe that you do care.

The people of the tri-state region around Entergy Nuclear, Vermont Yankee are counting on you to advise against the uprate of this reactor. And your decision will be seen as a precedent nationwide. Vacuum breakers, steam dryers, NPSH, safe shutdown analysis, there are too many unmeasured unknowns to risk this experimental power boost.

Thank you very much for your time.

(Applause.)

CHAIRMAN DENNING: The next speaker is Celia West, followed by Ray Shadis, followed by Diana Sidebotham. You know, the presentations that we have had so far have had a lot of content. And I don't want to ask you to be brief for that purpose, but there are a lot of people who would like to speak. And so if you can, please be brief.

Is Celia West not here or Ray Shadis? Yes. Ray, why don't you go ahead, please? Fine. Paul Bousquet?

MS. NEITLICH: Actually, I'm before Ray Shadis.

CHAIRMAN DENNING: Okay. You sit up there, please. Now, this is totally unfair.

MS. NEITLICH: This is fair. This is very fast. These are the children of our community. What is your name?

(Whereupon, children were introduced.)

MS. NEITLICH: Okay. So these are the children whose lives your decision is affecting. Sophie would like to say something.

SOPHIE: I think the nuclear power plant is unsafe. And I feel uncomfortable because it could hurt you. And I don't think it should operate.

(Applause.)

MS. NEITLICH: Thank you very much. Okay. So I would say just about all of these children live within the ten-mile evacuation zone. Oh, I'm sorry. My name is Jill Neitlich.

I see a lot of incredible parenting around this area, I mean, just parenting that I am really awed by, mothers, fathers. My primary job as a parent besides loving my child is to protect my child, to keep him safe.

Is your primary job, gentlemen, to keep us safe and our children safe or is it to protect the interests of Entergy?

CHAIRMAN DENNING: We know the answer: to keep you guys safe.

MS. NEITLICH: It is to keep us safe. Great. So we are all working --

(Applause.)

MS. NEITLICH: Great. Okay. Good. I'm glad to hear that. We are all working towards the same purpose. And because of that, I would like to give you this. This is my resume. I am not an engineer. I am a social worker. I am very strong in matters of ethics.

I am going to volunteer to work with you gentlemen. So whenever you have a meeting, please call me. I will get there. Here you go.

(Applause.)

MS. NEITLICH: And I really mean that. I would love to work with you guys. And I would like to be part of it. If you really want to keep us and our children safe, I would like to be part of it. Okay?

I would like to tell a story about Alfred

Nobel. Everybody knows who Nobel is. He's known for the peace prize. Well, what a lot of people don't know is that he actually made dynamite until one day someone accidentally put his obituary in the newspaper when he was still alive. And they referred to him as something like Dr. Death. Nobel was horrified. And because of that, he created the peace prize.

So I just want to say one thing. I mean, yesterday I mentioned to you guys that I was wondering how your minds work. And I'm still wondering. So, you know, when people get towards the end of life -- and I'm not saying you're getting towards the end of life. I'm just saying that what people do towards the end of life, they start to do a life review. And they think "What was the quality?" They don't think "How much money did I make for Entergy?" They think, "What was the quality of my love? How well did I love?"

And so I am wondering, when you get older and start doing a life review, are you going to start thinking, "Oh, boy, I really blew it, you know. We created more nuclear waste for my great grandchildren, great great great grandchildren. And they're going to be with this waste for 30 stinking years, 30" -- think of that -- or when you view this life, are you going to think, "I have really done a good job. I am so proud of myself. I bucked the system, and I protected the people of -- I protected New Englanders"?

So, gentlemen, please call me. I'll be at your meetings. And just think about this idea of matters of the heart. Thank you.

CHAIRMAN DENNING: You were going to go next. Is that --

MS. NEITLICH: Ray Shadis is next.

MR. SHADIS: Thank you, gentlemen. I will try to make this quick. I fully intended to balance the meetings at the end of the month. And I also have a couple of quick points.

Number one, I heard today as sort of an urban legend repeated over and over again that Vermont Yankee is unlike Maine Yankee. Maine Yankee was a plant that was -- the management was upset because of a manipulation of a computer code dealing with fuel clad temperatures under small break LOCA and that Vermont Yankee does not have any of those kinds of issues; therefore, shouldn't be considered for independent safety assessment.

I wonder if that is patently untrue. The independent safety assessment for Maine Yankee was not ordered because of any flaw in the management of Maine Yankee.

That was already being taken care of. That question of a manipulation of the computer code was being dealt with by the Office of Inspector General and by a team convened out of NRC headquarters for lessons learned at Maine Yankee.

The question, the driving force behind the ISA, was the failed NRC oversight at Maine Yankee. The project manager, Pat Sayers, was getting ready to go on vacation. The computer code was one of the last things that needed to be signed off on. You know, he never checked it out. He took the company's word that they had rechecked it and everything was okay.

And what NRC did is they recognized that that was not adequate oversight, that was not the kind of oversight that was protective of public health and safety. And the ISA was ordered to yes, evaluate Maine Yankee but evaluate Maine Yankee in terms of NRC's ability to conduct real reactor oversight, whether or not their endless run of systematic licensing and performance scores were justified. How could they have missed this issue?

And what they found was they had missed many, many, many issues. There were 33, some major safety-significant issues that they missed. And, you know, even doing the ISA, they opened up the cable, say. They looked inside and said, "Yes, everything is firm and fully packed," but they never determined whether or not the company actually had wiring schematics that they understood or where there were cable separation issues. And ultimately that was the big ticket item that shut the plant down.

So I beg you. Don't tolerate the next salesman coming down the road to say that Maine Yankee underwent an ISA because of poor management. That was not it at all.

And I think here the issue is not so much whether Vermont Yankee deserves to have a diagnostic evaluation so much as whether or not the people of Vermont deserve to have Vermont Yankee undergo that. It is their community. And they are looking for reassurance.

I have the largest, probably the largest, collection of nuclear materials information records of anybody in New England, perhaps in the United States. I own an entire public document room. This is true, came from the Maine Yankee public document room. All 9,000 pounds of microfiche are mine now.

Included in the documents are board meetings and executive committee meetings of the Yankee owners at the time that it was questionable as to whether Maine Yankee, Connecticut Yankee would continue operating. They openly referred to NRC terming the problems at the Yankee plant as the Yankee disease. And the question was, how can we escape the onus of the Yankee disease?

Ross Barkhurst, who was the CEO at Vermont Yankee, was at that meeting. And he scurried home from that meeting to see what he could do to bring Vermont Yankee out from under that shadow. And it's not ancient history. This is ten years ago.

CHAIRMAN DENNING: Would you comment on vertical slice versus --

MR. SHADIS: Sure. Pardon me?

CHAIRMAN DENNING: Yes. Would you comment on what your perception is of a vertical slice approach versus a risk-informed approach like was described?

MR. SHADIS: Yes. And if I may reference it to the experience at Vermont Yankee because I didn't follow through with the one at Cook or any of the earlier programs and what happened at Maine Yankee.

Maine Yankee had -- they had 25 people on site in 2 series of on-site visits. And I forget whether that was 2 weeks or 4 weeks, but one way it's

4,000 hours, the other way it's 8,000 hours. And the team itself declared that they had spent twice that time back at headquarters preparing, analyzing, summarizing. And so you're looking at modestly 10,000 to 20,000 hours and maybe more. So the intensity of that inspection was something quite different than what was recently done here at Vermont Yankee.

The other thing is that the deep vertical slice, the second, did pitch 4 systems at Maine Yankee, 4 out of 30-some plant systems. And we objected to that at the time. We didn't think it was enough.

They went down through the system top to bottom and investigated not only the material condition of the plant but all of the licensing documents that it had, the design basis documents, and then operations as it applied. And wherever they found anomalies, things would stop. And the inspection would then progress horizontally.

So it was both a prospecting slice down through the system and then, if you will, a strata mining slice to really determine extent of conditions. Root cause analysis was plugged into it.

And that really tells you not only is the plant in reality what it is supposed to be in its documents, but also it tells you something about the way that the plant has managed. More than that, it tells you whether or not oversight of the plant is tasked to do these things.

And so in so many respects, it's different because of that flexibility. In the case of Vermont Yankee, we had a team come to the plant that was not as independent of the plant as the one at Maine Yankee.

Maine Yankee they excluded people from NRR as far as I know and they excluded people from region I. They really had to scratch around the country to find the team. I lost my train of thought. And I'm sorry because I don't want to take up too much time with this.

They came in with a thorough understanding of the plant. They did an incredible amount of prep work before they came to do that inspection. It didn't happen at Vermont Yankee.

The team that came to Vermont Yankee had 90 issues on a kind of wish list. Of those 90 issues, approximately half were eliminated because those particular items or activities did not exist at Vermont Yankee. The guys didn't know when they walked in.

So when they did that first call, it wasn't because they were claimed because yes, they looked at it, it was okay, or any preliminary thing like that. It was largely because it didn't even apply to Vermont Yankee. Then they take 45 items. We mentioned that yesterday.

Out of that sample, the sample of 45 that you find 8 indications, that's a very strong signal that you ought to be looking further. As it was, they only did, in their words, limited extent of conditions review. They would not define what limited meant, and I suspect it was very limited, not to pick up on -- so, anyway, sorry to go on like that, but you asked the question.

CHAIRMAN DENNING: Thank you very much.

MR. SHADIS: Yes. Any other questions we can take a quick shot at here?

(No response.)

MR. SHADIS: It was mentioned --

MEMBER WALLIS: Well, you know, the staff --

MR. SHADIS: Sir?

MEMBER WALLIS: The staff claims that the approach they took in their --

MR. SHADIS: I'm sorry. I'm having

difficulty hearing you.

MEMBER WALLIS: Well, I don't know whether I have to use a different language or what.

MR. SHADIS: No, sir.

MEMBER WALLIS: I don't want to deafen you because this seems to be resounding throughout the room here.

The staff this morning claimed that their approach was better than the Maine Yankee approach. And I understand that the people here from the state accepted that there needs to be such a level of the people who were here --

MR. SHADIS: Yes.

MEMBER WALLIS: -- accepted from the department --

MR. SHADIS: Yes.

MEMBER WALLIS: -- that this met what they were expecting.

MR. SHADIS: It's more, a little more, than dealing with the --

MEMBER WALLIS: We have somehow to weigh what the staff claims against what you are claiming. It's not as though there's a clear-cut issue.

MR. SHADIS: Yes.

MEMBER WALLIS: We have two different

views of the adequacy of this inflection. And it's not clear-cut until -- you know, there are both sides to consider carefully as to what the result of this evaluation should be.

MR. SHADIS: My intent, Dr. Wallis, would be to provide you with the documents that build a history of this as it went along. I think right now suffice it to say that the Department of Public Services' prediction from the beginning of this call for an ISA in early 2003 was that it was unnecessary. And, in fact, this was fought through the Vermont Public Service Board right down to the wire.

And Mr. Sherman's testimony was that Vermont Yankee is an exemplary plant. And you do not bring this team of inspectors on an exemplary plant that doesn't deserve this sort of thing.

And so, you know, his perspective was informed by that viewpoint. If you're going into it -- and we have objected to his being included as the representative of the public member on that team.

I will tell you, by the way, in the Maine Yankee inspection, we had not only our state leaders inspected, but we also had hired in a consulting engineer. And then we had a review committee of five citizens appointed by the governor to follow; that is, section through.

But I will provide that information for you and see if we can't flesh that out. The other thing I'm going to recommend highly to you is that you read the reports.

The ISA, by the way, is not a big, fat report like this one. The SER is 75 pages. Read it. And we'll provide our comments that we also provided to the Commission at the time that that report was done. We had a citizens' review of that ISA. And I would be glad to provide that.

But the real comparison here is not between -- and I am forgetting myself -- not between the ISA and this inspection that was done here. It's between the request of the Vermont Public Service Board for a particular type of inspection for a particular purpose.

And that was the fourth, and they wanted it for the purpose of trying to determine reliability. That was their intent. They also stated that they wanted it for the purpose of satisfying to some extent the concerns of the public in calling for an ISA.

And I think if it doesn't -- it may be a wonderful exam. In fact, Dave Lochbaum, whom you have all heard from, thinks it was a tip-top inspection.

And from everything that I looked at, it was a fine inspection. It was a heck of a lot better than the run-of-the-mill one that they are trying to replace. And let's not forget that that was the purpose of it, by the way.

CHAIRMAN DENNING: You do have somewhat similar points.

MR. SHADIS: I do. And I'm sorry to take so much time. You gentlemen were kind enough to invite New England Coalition to present at your meeting on reg guide 1.82, revision 4, the net-positive suction head question, containment overpressure question. And in that meeting, I suggested to you that you investigate the Vermont Yankee containment safety study of 1986. It was forwarded to Harold Denton at NRR in 1986.

That document done under pressure from the State of Vermont was Vermont Yankee's attempt to do a real analysis of containment safety at this plant. And I need to quote a couple of things to you.

There are two components or two activities that they bring up which are challenged when you start to move into the space of allowing containment pressure or depending on containment pressure to build up.

And one of them is the dry well spray system. The other is primary containment denting if that option presents itself. And in both cases, the company says if you turn on the spray, you're going to lose the pump. You're going to chill the atmosphere in the containment. You're going to reduce pressure. And you will lose the pump. And they make it abundantly clear.

And, likewise, with denting, let me just read a couple of these quotes to you. I did ask NRC staff to provide copies of this to you. And I don't know if they did.

These are so definitive. This is not the hard-to-understand language that we heard yesterday and this morning. And I don't know if people will understand this kind of question, but okay. Dry well spray capabilities, 5.3, identified issues.

The first issue -- we're throwing this one in for free. The first issue is the task of containment implosion. Design negative pressure of two pounds per square inch will not be exceeded provided that vacuum breakers operate as design.

Someone here raised that question about vacuum breakers. The NRC staff didn't know anything about the vacuum breaker issue. All of us that had been reading in the LERs know that we have recently had an episode on vacuum breakers, but basically what we're looking at here is a design limit of two pounds per square inch negative pressure that would cause a collapse of the containment.

Secondly, ECCS, emergency core cooling system, pump, net-positive suction head is a concern, as is the case with containment venting, section 5.4. If sprays are utilized when the containment is pressurized and Torus water temperature is elevated, the resultant new pressurization could impact the available net-positive suction head of pumps taking suction from the Torus.

5.4, severe accident containment failure. If we go to venting, NRC believes that containment venting should be available to avert uncontrolled overpressure failure of the containment in certain severe accident scenarios.

5.4.3.2, anticipated transient without scram venting postulated to relieve pressure and preclude failure of the dry well shell, leading to an anticipated transient without scram success path.

However, it says. However, containment venting may also jeopardize continued core cooling in this scenario. The pressure suppression pool would quickly become saturated and would boil if pressures were significantly reduced.

The operability of the reactor vessel injection system pump that takes suction from the pressure suppression pool would be compromised due to inadequate net-positive suction heads and resultant pump cavitation.

If these injection systems are the only ones available, the degradation or failure of pumping capability could lead to core uncovery and core melt might actually be caused by wet well venting.

I am not going to read the other couple of examples. It's just, in essence, a repeat of this. But basically what they were saying is here are two safety-related options you have. Use this system or use this method. Don't do it because if you do, you're going to lose the pump.

This is not a tempered statement. This is not qualified. This is flat out objective statements on their part. And what has not happened, as far as we can tell -- now, the attorneys for Entergy in the Atomic Safety and Licensing Board case have asked that they not have to provide discovery on the other party's issues to us.

So we, New England Coalition, have been

precluded from getting the discovery on net-positive suction heads. Other than what may be in that, we have searched the documents.

We have searched the SER. We cannot find a reference to this containment safety study. And our objection is that if it has been surpassed with new information, that it must at least be referenced to say that the new information contradicts these conclusions and here is why. All right?

I beg that if you haven't already gotten it, get a copy of it and go through because, if for no other reason, these are the kinds of documents that those of who are concerned about safety and these plants review. We depend on the information in them as well as the NRC documents.

MEMBER SIEBER: What document is that, sir?

MR. SHADIS: This is entitled "Vermont Yankee Containment Safety Study." And it was provided to Harold Denton in a transmittal letter August 1986.

MEMBER SIEBER: And who is it from?

MR. SHADIS: This was performed by Vermont Yankee, apparently together with consultants because the voice and hand are different as you go through the document. But it doesn't say in the document that we have.

If you wish, if you have a hard time to find it, we will go ahead and copy all 300 pages of it and get it to you. You know, we'll be glad to do that.

MEMBER SIEBER: I'm not sure we want to put you to that burden. On the other hand, I'd like --

CHAIRMAN DENNING: We can handle that.

MEMBER SIEBER: I would like to see it.

MR. SHADIS: Yes. There is a section of -- there used to be. When the NRC public document room was on -- I think it was on Pennsylvania Avenue or right near Pennsylvania Avenue.

MEMBER SIEBER: Yes.

MR. SHADIS: There was a whole section of the PDR they called the black hole, which is where documents they didn't quite know how to label wound up.

CHAIRMAN DENNING: Are you done?

MEMBER SIEBER: If you could let Ralph know?

MR. SHADIS: I am. Thank you very much.

MEMBER SIEBER: Maybe you could let Ralph Caruso know how to find it.

(Applause.)

MR. SHADIS: I'd be glad to.

CHAIRMAN DENNING: Paul Bousquet? And he will be followed by Diana Sidebotham, Bill Pearson, and Gary Sachs.

MR. BOUSQUET: Good afternoon. I promise not to be so articulate.

(Laughter.)

MR. SHADIS: Or long-winded.

MR. BOUSQUET: Or long-winded. I'm just a builder from up in the valley. My family has been in the hills forever. And I'm here as a terrorized citizen defending my homeland.

Paul Bousquet, Bousquet. So if I offend anybody, I have written this lastly. Don't take it personally. You seemed like a lot better, nicer guys than I really thought I was going to deal with.

(Laughter.)

MR. BOUSQUET: I realize you people were paid to be here today. And although that's not as good as you being here on your own, out of your own true concern for us, I still appreciate it anyway.

Of course, us are the unpaid citizens living in the danger zone around Vermont Yankee, not to include the paid employees from the plant or anyone else in a position to gain from your final decision.

For the life with me, I can't understand why an employee as mentioned would want the added risk of an uprate unless there was either a kickback or a threat involved.

That said, I would like to get to the real question. Are the benefits from an uprate worth the risks involved? It took VSNAP two years to even come up with that question. Hopefully they'll get to vote on it before the final decision is made.

I'm not sure as to how much pull you people actually have, but I do wonder what you think. If you have done your homework, I'm sure you know about the Maine group and the thousands of individuals that are opposed to this uprate. Personally I think it's immoral to even attempt, especially since Vermont has stated that at this time we don't need the extra power and we damn sure don't need the extra weight.

The Vermont Natural Resources and Energy Committee took months to work up a bill concerning the waste problem, only to be tricked into having the bill stripped of the earth and berm and the Health Department fence-line monitoring provisions, adding onto that the statement of no uprate, no tax paid on their way.

Are you gentlemen aware of that? If the uprate does not go through, this waste stays in Vermont forever. And they won't have to pay a dime. If this bill

They took the bill behind - quickly, behind closed doors and voted, after suspending the house rules here in Vermont. Gentlemen, we were tricked and extorted by Entergy. We've had legislators publicly apologize for the way they were tricked into voting the way they did.

When questioned on why Yankee wanted the uprate, the Senior Liaison Engineer said that without the added revenue from the uprate, his company wouldn't be profitable enough to afford to pay storage fees. Does that make any sense to you? You're smart people. Does it make sense to make more waste to help pay to store the waste that you don't know what to do with?

All this on top of the fact that Entergy would not release any statement of what their profits actually were. This is a clear situation of a multi-billion dollar corporation extorting our legislators and then attempting to steamroller the thousands of people who opposed them. Years ago, when I went to get a license to drive tractor trailers, I was forced into getting a complete physical.. Not a check-up, but the most thorough physical available. The cost of a physical was not even discussed, because public safety was top priority. The exam that Vermont Yankee got - was given is a disgrace. We didn't even get the vertical slice that we were promised.

The number of hours varied, but if you don't count the hours of office time the Vermont nuclear engineers spent, they don't add up, either. Do we also count his hours eating his lunch? Even with the inflated numbers of 950 hours, this is not the most complete physical exam we could have.

Something so iffy as taking an old plant almost ready for retirement and taking the governor off, without the best inspection we could have, is irresponsible. Funny, that's the word our state nuclear engineer used when we demanded an ISA - irresponsible. I'm sure you are all familiar with the ISA that went on at Main Yankee in '96. Twenty thousand hours, give or take.

Our inspection was three or four percent of what Maine got. Do they feel that Vermont people are worth three or four percent of Mainers? No, Maine officials were out to prove how safe their reactor was, and it backfired. They found so many things wrong, they could not afford to fix it, so they closed it. Is this the fear here? If it is just the cost of the better inspection, then why don't you ask for money from the thousands and thousands of worried people who signed the petition, demanding a true ISA?

I, for one, have never been given a proper explanation why we can't have a similar IPA in Maine. The last thing I would like to speak about today is moral responsibility. Today, or in the near future, you will be asked on this uprate. You have a moral responsibility to make a good choice.

I am not stupid and I understand that many of you might be yes men, and your actual employment might be at stake. But through your actions, or through your inactions today, you are placing your name on a list and don't think that the corporation will take the heat and you will be spared if something goes wrong.

I have come to most of these meetings and begged and pleaded to people to take moral responsibility for their actions. I am done begging. Today I stand here as a possible radiation refugee, and I make you the promise, should anything happen as a result of this crazy proposition to uprate this old power plant, purely for Entergy's process, then I will personally distribute this list of names and do what I can to bring you to justice.

(Applause).

MR. BISQUET: One last bit and I will be out of here. I have had 180 degree turnaround this week, and I - my heart has changed, and I think I see through the smokescreen here. And in light of the many more cracks found at the steam dryer, why would Yankee use a better camera in the 11th hour to find cracks if they wanted it to go through?

It wasn't the NRC. It wasn't you guys. It was Yankee. They didn't have to do that. It think Yankee and Entergy will save face after seeming to push so hard for the uprate, only to be the real winners, escaping from the true cost of storing their waste here in Vermont until the end of time.

And the recent controversial Yucca Mountain and the lack of any new yucca, and the cutting of the funding for any interim sites - you can see my point here. We're going to get stuck with this waste. We're not - they're not going to pay a dime. Not a cent.

The last thing I want to say, why did this happen? Our legislators took four months to accomplish this. Three guys went behind three closed doors - the governor's men and the governor - they changed everything. They gutted it. Now, the governor is a man - I - you know what this is? You know what it represents?

A couple summers ago, they lose some fuel rod - a couple broken pieces. They looked for months and they couldn't find them. Our governor, who's running the show here, he went on public TV and he stated, thank God it wasn't new fuel.

(Laughter).

MR. BISQUET: I rest my case.

(Applause).

MR. BISQUET: Thank you.

CHAIR DENNING: Next, we have Diana Sidebottom, Bill Pearson, and Gary Sachs, in that order. Is Diana here? And correct me, please, if I mispronounced it.

MS. SIDEBOTTOM: Good afternoon, gentlemen. Thank you very much for the opportunity to speak. I'm President of the New England Coalition on Nuclear Pollution and was privileged in 1971 to be one of its founders. So I will just speak briefly today about a little history and a bit of philosophy.

We were involved with the New England Coalition and the original licensing of Vermont

Yankee. One of the issues which we've pursued, of course, was the mark one containment. We did not know at that time something we discovered a number of years later, and that was that the - the deficiencies in the mark one were well-known by the nuclear industry and yet, it has - it was a license.

Since then, it has - various fixes have been instituted to relieve the - some of its deficiencies, such as the supposed venting of radioactive fume in the event of a serious accident to protect the machine.

In 1986, as Ray Shadis pointed out, a study of containment was ordered, because at an industry meeting, Harold Jenkins was quoted in *Nucleonics Week* as saying that in the event of a serious accident, there was a 90 percent chance of containment failure.

So, venting, a few years later, came into being to relieve the pressure on the containment in the event of an accident and now, we hear that perhaps there is need for a credit for overpressure in the event that an uprate should occur, and they would lose that.

In regard to protecting the mark one containment and venting, I was rather deeply involved in that particular issue when it came up in the mid-80s, and tried very hard to gain from various of the NRC people who came to Vermont to appear before the Vermont State Nuclear Advisory Panel how much radiation would emanate from the plant through the vent in the event that that needed to be used.

Several people simply refused to answer. Finally, from Dr. Banero (phonetic), I received the answer that a maximum of 50 REMs might be spewed forth onto the unsuspecting public in the event of an accident. About the same time, we learned of a study which had been done by Dr. Terry Las (phonetic) in Illinois to the effect that in the event of a fast-breaking accident, a thousand-megawatt BWR - as much as 1,600 REMs - would be discharged.

Now, just a bit of philosophy, or rather, early thinking. One of our science advisors had been a nuclear pioneer, he was professor emeritus and the University of Massachusetts, and a member of the San Francisco Bay Committee for Nuclear Responsibility. In August of 1973, he wrote the following words, which carry an even greater urgency for mankind today:

The dangers inherent in the production of nuclear power have been increasingly apparent and I consider it irresponsible to go ahead building new nuclear power plants. Of the many dangers, the three that concern me the most are the likely diversion of plutonium to make atom bombs for terrorists; the possibility of disastrous accident at nuclear power plants; and the unsolved problem of permanent storage of high-level radioactive waste.

We need a moratorium on nuclear power very soon. Until there has been urgent and determined development of alternative power sources to the point that wise decisions can be made about the best mix of energy sources for the future, without a moratorium, commercial sectors will preclude a decision and we will drift into a perilous dependence on a plutonium economy.

I'll simply close with a statement from a Nobel Laureate. This is an abbreviated version of a few more lines that he wrote. Energy is safe only if a number of critical devices work as they should; if a number of people in key positions follow all of their instructions. The enormous quantity of extremely dangerous material must not get into the hands of ignorant people or desperados. No Acts of God can be permitted.

Thank you very much.

(Applause).

MS. SIDEBOTTOM: I'm pleased to meet with you today and to hear your very excellent questioning of this particular proposal, which threatens us, we believe - our lives, our property, our homes, and all we hold dear. Thank you very much.

(Applause).

CHAIR DENNING: Next is Bill Pearson, followed by Gary Sachs.

MR. PEARSON: Hi, my name is Bill Pearson. I'm really in awe of all of the comments that have been made. Maybe one thing that I can add to the discussion this afternoon is the dimension of morality. Using nuclear - using radioactive irradiants to heat water, to turn turbines, to make electricity, is a moral blunder of epic proportions.

By what conceivable system of morality can we justify the protection of deadly radioactive waste, thousands of tons of it, year after year after year after year, with, as we all know, still no safe and secure permanent depository, and then saddle our children and thousands of future generations to pay for its protection and safekeeping?

How is it morally justified to sanction the technology that knowingly produces raw materials suitable for nuclear bombs? What - that concoct evacuation plans that are currently doomed to fail and certain to doom thousands of people unable to flee, that subject the population to the worry and fear and uncertainty of a major catastrophe, such as Chernobyl or Three-Mile Island, happening right down the road?

What madness propels us in this enterprise when energy efficiency alone would preclude the need for even one watt of power from Vermont Yankee, when alternative energy sources are available, but just not with the billions of dollars in taxpayers' - I was saying, when alternative energy sources are available, but just not with the billions of dollars in taxpayers' subsidies doled out by Washington to the nuclear industry?

If Entergy Vermont Yankee is serious about safety, as they claim they are, and if the Nuclear Regulatory Commission is serious about safety, then there should be no - then they should be more than willing to conduct a thorough and complete independent safety assessment.

In closing, I'd like to tell you about a little boy, then almost five years old, who attended that public hearing in Vernon some years ago with about 500 other people. It was about the Vermont Yankee uprate.

His name was Julian. Some of you may have been there. He came with his mother, bringing what he called tickets. I think he had traffic tickets in mind. He brought these tickets to the big boys in suits from the Vermont Yankee Factory. The tickets read: Stop polluting the air and the water. Stop harming the turtles, birds, and rabbits and making the fish sad. And keep the children safe.

We can get energy from the sun, Julian pointed out. The sun doesn't pollute. Smart kid.

(Applause).

CHAIR DENNING: Thank you. Gary Sachs, followed by Sophie Kaye and Water Swelinski.

MR. SACHS: The issue I wish to address - and I'm going to read, because I get too heated - but I'm also going to give myself time to make sure I get it right. I guess I want to say, this is the last hurrah, in a sense, before this uprate happens, and this uprate's tied in - as was spoken earlier - to dry-cast storage and license extension and if they get one, they get it all, and we lose.

So you're here because you guys said you'd be back and they brought you with them. The issue I wish to address is that the public is getting the wrong end of this proposed uprate.

I have read ACRS quotes from I think it was 2001, which is when these extended power uprates began - although I've heard that they're so well-researched and so well-done, they've only been existing for four years - that extended power uprates increase risk of equipment breakdown, increase brittlement (phonetic), increase the risk of flow vibration, or damage from increased steam vibration, increase heat decay, possibly increase radiation dosage, decrease the time for operator reaction.

And I'm not an engineer. I don't intend to reach beyond my scope as a local concerned resident, and it's as a local resident that I'm wishing to offer you my concern. A lot of us are stressed out, so forgive me if I start something and lose it. There have been three nonbinding referenda locally. There's been something called Town Meeting Day, which is Vermont's annual exercise in participatory democracy.

Senator Gant (phonetic) spoke of that two of them lost 49.2 to 50.8. I personally don't really consider that losing. The last - oh, they spent huge bucks on it. The last one, we one. I think it was 52 to 48.

MR. SIEBER: Could you tell us what the

issue was on the last one?

MR. SACHS: The issue was to shut down the reactor in 2012 and for people stating - I think it was - I believe Mr. Anthes, who spoke earlier, read you the exact --

MR. SIEBER: Thank you.

MR. SACHS: I heard this morning that the Department of Public Services states itself to be firmly in support of Vermont Yankee, and they've also stated that position clearly to the Public Service Board. I get confused here. The Department of Public Service is supposed to be the ratepayer etiquette.

I get confused. Are they hedging their bets? The Department of Public Service says they're in support of Vermont Yankee. Vermont Yankee is a huge financial asset in the States. They are - they have the ability to pay things off $20 million at a time - corporate citizenship. Yet, it was Bill Sherman who spoke to you earlier, quite loudly, speaking of containment overpressure, who found that issue and brought that forward.

To me, that feels like they're playing both sides of the coin, that no matter which way it goes, the Department's going to be able to come out saying, see what we did; weren't we good; we were on your side - to us, the public.

So on those referenda, Entergy spent huge amounts of money, I mean, a thousand percent more than what was spent by those people who oppose Vermont Yankee. Entergy often uses its assets, basically, to sway regulatory approval.

The Senator stated to you that the Public Service Board of Vermont makes their decisions based on economic issues. That's true. The Nuclear Regulatory Commission is mandated to make decisions to focus on safety. That is true. That leaves a vast gray area that no one yet has been willing to step into.

It would greatly please me if you gentlemen would have the courage to do so, to reach into that place between the economic interest to the State and the issues of safety that have been raised by the likes of the New England Coalition and by the other people.

To look at a safety evaluation report requires a huge amount of effort and a huge amount of study and a lot of time. That's my family time. That's Ms. Shaw's family time. That's every person out here's family time. We're not paid for it.

We don't like - I've got potassium iodide in my pocket. I don't like having to live with potassium iodide. I have to get woken up at 3:00 in the morning because of high winds in Albany. I don't like it. But it's something I live with, and I'd rather be informed than not.

I have plastic, because FEMA said, cover my windows in plastic. I don't - oh, sorry, that's Homeland Security. I don't believe it. I don't like living in that shadow.

So I want you gentlemen to know that it's your determination on this uprate issue that sets the precedent for the Public Service Board for Vermont. The Chairman of the Public Service Board who heard the uprate case is no longer the Chairman. The Chairman of the Public Service Board who heard the fail (phonetic) case is no longer the Chairman. The other two individuals of the three-person Public Service Board are the two making decisions.

Your decision sets the precedent. It is - there's more weight, more onus on you gentlemen. It's a huge, huge step. I know that no uprates have yet been denied by you gentlemen. I know that. I know what percentage - I know far more of this stuff than I'd like to.

The uprate proposed is entirely for

Entergy's profit. There is a member of the Public Service Department sitting in the front row here who stated in July of '04, I believe, that if Vermont Yankee would close tomorrow, there was enough electricity in the New England grid. We don't need it.

The only power from the proposed uprate that is being sold inside this space was an under-market rate agreement that Entergy made with a small company up North, and there is a - you don't know - there is a huge gap between what goes on in Wyndham County and why the hell there aren't 5,000 people from Mount Perior (phonetic) down here. Excuse my passion.

They don't get it. They don't even know where Vernon is. Do you? Okay. It's five miles - oh, nine miles south of here. I heard - okay, I want to step briefly to the issue of the - I don't know if it was the NRC - I think it was the NRC earlier that spoke that you've been doing routine engineering inspections for all uprates. I don't recall who it was that said that.

I'm not certain if that person was - or if it was ACRS, I'm - which is how I'm assuming you guys are positioned, although I don't know that - I'm not certain if you're referring to all the different types of the measurement uncertainty recapture uprates, the stretch uprates, and the fairly new extended power uprates. If it's the extended power uprates, you haven't been doing very many - many of the what are now extended power uprates happened after the earlier, smaller one.

Our Public Service Board, on March 15, 2004, when they passed down their conditional approval of the uprate, did not ask for a routine engineering inspection. They called for very specifically, as a condition of uprate approval in the state regulatory process - and I'm grateful to live in a state with a regulated utility system - it's scary enough we may end up looking like California come this summer - they ask for an independent engineering assessment.

As I mentioned yesterday, six weeks later, the NRC wrote back saying, we have been working - planning this for a long time. As I said then, I don't believe it. They called for, very specifically, two safety-related systems, two maintenance-rule systems, and two deep vertical slices - one into each.

And X amount of people have laid out - I believe Mr. Anthes began, literally read you what the order stated - I do not believe that what the NRC did with their last August of '04 to September of '04 independent engineering assessment - I do not believe that that foot the bill for two safety-related systems, two maintenance-rule systems, and of those, two vertical slice systems.

The most important thing I want to say, I'm going to reiterate, it's your determination that I believe sets the precedent for the Public Service Board. The Public Service Board - those two members left - are the ones who will decide for this state, whether or not you - if you give your approval to them.

One of the member's a teacher, one of them's a businessman. They're not engineers. The Chairman who left was a member of EPRI (phonetic). The man who has refused himself from this case is a former head of the department, so I'm not sure which side he's on.

You may or may not already know about what happened yesterday out in Dresdon (phonetic) with the repairs made to their steam dryer. The repairs were made two years ago. Yesterday, the repairs were found to already have fissures in them. If you don't know yet, you will soon.

I also assume that you already know the quote from the former NRC Commissioner, Peter

Bradford, that Vermont Yankee has never produced power for less than ten times the amount that the legislature in 1957 was told it would produce power for.

Thank you very much for allowing me to speak.

(Applause).

CHAIR DENNING: Walter Swelinski, please?

DR. SWELINSKI: I'm Walter Swelinski. I'm a physician, and a musician. I coach the jazz works up at the High School. I'm deeply embedded in this community and I'm knowledgeable in medical and basic science issues.

The first time I spoke at a meeting of this sort was about 30 years ago in Northern Ohio. There was a proposal that went through to build a nuclear power plant at that time. My concern then and many others' concern at that point was related to what was going to happen to the fuel once it's spent, no longer useful for generating electricity.

There had been assurances from the industry and from the Federal Government that this problem would be taken care of. The project has obviously gone forth without a solution to this serious recurrent, unsolved, and perhaps unsolvable problem.

As everybody knows, recently, the Legislature of Vermont allowed Vermont Yankee to store its spent fuel in dry-cast on site as a temporary measure, awaiting permanent storage in such a facility as Yukka Mountain. Most people in this room probably also know that that - Yukka Mountain has been enormously studied. There's enormous controversy around it and just in the last two days, the Congress of the United States cut the funding for continued investigation there.

For all practical purposes, there is no long-term solution for storage of spent fuel, and after 30 years, it's reasonable to think that there won't be. It's not controversial whether or not spent fuel poses a health risk to the community where it's stored. No one contests it.

For all practical purposes, Vernon has been turned into a high-level long-term radioactive waste dump. People in this area will live with this for the rest of their lives. I don't really have any question about this.

This is what I spoke to 30 years ago; this is what I speak to now. I'm not representing anyone but the public and - a public that feels betrayed by its government and this industry. This is a significant problem that won't go away. It hasn't been solved.

For that reason, I'm opposed to the current proposal to increase the productivity of Vermont Yankee. It will create more nuclear waste and increase the threat to the people living in this area.

I have one other thing to say that people might not be aware of. There's been a lot of discussion about evacuation plans, and whether or not we can get people out of the community fast enough, if something goes wrong at Vermont Yankee. Several years ago, I was curious about this and made some contacts, asking about some of the details of what went into this.

The general thought was that if enough radiation was released into the community, where it would increase the long-term cancer risks of people living under that amount of radiation by a factor of I believe it was three, then people should be evacuated from that area. People are concerned they can't get out fast enough.

My concern is actually the opposite. I want to stay. My concern is, I'm not going to be able to come back. The U.N. undertook a study in 2002 of the evacuation of Chernobyl. About 160,000 people were evacuated. It was the worst nuclear accident in the history of the world.

The result of the U.N. study was that in fact, they felt that the health consequences of the evacuation exceeded the likely health consequences of staying put. People were evacuated, they lost their community, they lost their jobs, they lost everything. They became wards of the state. They went on welfare. They developed diseases and conditions associated with not having anything to do: depression, obesity, diabetes, heart disease.

The U.N. felt that it was better that the evacuation never occurred in the first place. This is the worst nuclear accident in the history of the world. I'm not reassured by anybody's plan about how quickly I and my children can get out of here. I own my land. I own a house. I have no interest in ever living anywhere else.

I don't want to leave. And I'll tell you, if those whistles go off and there's an accident, I'm not. I'll be one of those that the - I'll be one of those troublemakers that - like the people in New Orleans who stayed, who didn't want to go off to some refugee uncertainty. I'm not eager about that.

Thank you for listening to me. I have grave doubt as to whether there will be any change in the course of nuclear energy in this country. The public that I see everyday has a sense of betrayal by its corporations and its government at this point. As much as you are well-meaning representatives of the government and the corporations involved, I came here to listen to what people have to say. I don't get paid at all for being here. It's my family time. It's not easy to come. The people in this community are concerned. We are not reassured. Thank you very much.

(Applause).

CHAIR DENNING: Thank you, Dr. Swelinski. I would very much like to thank the public for the input that they've provided. I'm sorry. I'm sorry. And there may be others like you, but you have had a chance to speak. We do have to catch a plane. I'm very sorry, but - because we have another meeting that we have to do tomorrow in Rockville.

But I would like to say how much it's meant to us to hear from you people. I don't think that you could've presented your case in any better way than you did. You did it very effectively. It's up to us to assimilate a lot of information. We hear what it is you're saying. We understand the passion behind it. We understand your concerns, and we will do our best to integrate all the information we get and do it in a way that is best for the safety of everybody.

I would also like to say that anybody who has prepared a presentation, please provide it to us and we promise that we will have our staff go over it and summarize it for us at our next meeting.

Thank you very much, and good night.

(Whereupon, the meeting was concluded).

CERTIFICATE

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

Name of Proceeding: Advisory Committee on Reactor Safeguards Subcommittee on Power Uprates

Docket Number: n/a

Location: Brattleboro, VT

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.

Pete Holland
Official Reporter
Neal R. Gross & Co., Inc.

ACRS Subcommittee on Power Uprates

NRC Staff Review of Proposed Extended Power Uprate
For
Vermont Yankee Nuclear Power Station

November 15-16, 2005

Opening Remarks

Cornelius Holden
Deputy Division Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Opening Remarks

- VY Proposed Extended Power Uprate (EPU)
  - 1593 to 1912 Megawatts Thermal (MWt)
  - 20% increase (319 MWt)
- 105 power uprates approved
  - 13 of 105 are EPUs
  - 11 of 13 EPUs are for boiling water reactors
  - 7 of 13 EPUs > 319 MWt
  - One other EPU approved for 20% (Clinton)
- Second EPU Review done with RS-001

Opening Remarks

- Review took over two years, 9000 hours
- Technical issues included:
  - Steam dryer integrity (flow-induced vibration)
  - Crediting containment accident pressure
  - Transient testing
  - Analytical methods and codes
  - Engineering inspection

Introduction

Rick Ennis
Senior Project Manager
Divsion of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Background

- Review Used Review Standard RS-001
- Requests for Additional Information (RAIs)
  - 8 Rounds
  - Nearly 400 Questions
- 41 Supplements to Application
- Audits & Independent Calculations & Analyses

Topics for 11/15 - 11/16

- EPU Power Ascension and Testing (11/15)
  - Safety Evaluation (SE) Sections 2.12 & 2.5.4.4
- Credit for Containment Accident Pressure (11/16)
  - SE Sections 2.6.5 & 2.13
- Engineeering Inspection (11/16)
  - SE Section 1.6

2-3

Topics for 11/29 - 11/30

- Mechanical and Civil Engineering
- Reactor Systems
- Materials and Chemical Engineering
- Electrical Engineering
- Plant Systems
- Source Terms and Radiological Consequences
- Health Physics
- Human Peformance

2-4

VY EPU Schedule

- ACRS Subcommittee Meeting in Vermont (11/15/05 - 11/16/05)
- ACRS Subcommittee Meeting in Rockville (11/29/05 - 11/30/05)
- ACRS Full Committee Meeting in Rockville (12/8/05)
- Issue Final Safety Evaluation (2/24/06)
- ASLB Hearing (TBD)

2-5

EPU Power Ascension And Testing

Robert L. Pettis, Jr.
Senior Reactor Engineer
Plant Support Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

3-1

EPU Test Program

- Standard Review Plan (SRP) 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," provides guidance for testing programs based on Regulatory Guide (RG) 1.68 and plant specific initial test program.
- EPU test program should include testing sufficient to demonstrate structures, systems, and components (SSCs) will perform satisfactorily at the requested power level.

3-2

EPU Test Program - continued

- Staff guidance considers original power ascension test program and EPU related plant modifications.
- Staff guidance acknowledges that licensees may propose alternative approaches to testing with adequate justification. Supplemental guidance provided in SRP for staff evaluation of alternative approaches.

3-3

Large Transient Testing (LTT)

- LTT was part of the initial test program.
- Staff previously accepted the following justifications for not performing LTT for EPUs:
  - Licensee's test program will monitor important plant parameters during EPU power ascension;
  - TS surveillance and post-mod testing will confirm the performance capability of the modified components;
  - Operating history and experience at other light water reactors (LWRs).
  - LTT not needed for Code analyses benchmarking.

3-4

Large Transient Testing - continued

- Staff requested additional information to support the licensee's basis for not performing LTT.
- The licensee's responses were based on the following factors presented in the SRP and consistent with previous staff approved EPUs:
  - Consideration of industry operating experience, including several unplanned generator load rejections which produced expected results;
  - Analysis of potential unexpected systems interactions;
  - Effects on design margin;
  - Limited scope of EPU modifications for balance of plant (BOP) systems;

3-5

Large Transient Testing - continued

- Analyses results bound operational transients experienced at VY and other uprated plants; and
- Conformance to previous NRC staff approved General Electric (GE) Constant Pressure Power Uprate (CPPU) topical report.

3-6

Summary

- SRP 14.2.1 allows licensee justification for not performing all initial test program power ascension tests.
- Thirteen domestic LWRs have implemented staff approved EPUs up to 120% original licensed thermal power (OLTP) without performance of LTT.
- Staff considered previous plant operating experience and no introduction of new credible thermal-hydraulic phenomena.
- Limited scope of EPU modifications.

3-7

Conclusion

- The licensee's proposed EPU test program, with testing required by license condition for the condensate and feedwater system discussed in SE Section 2.5.4.4, satisfies the staff guidance in SRP 14.2.1.

3-8

Test Considerations for Plant Modifications

Steven Jones
Senior Reactor Systems Engineer
Acting Chief, Balance of Plant Section
Plant Systems Branch
Divsion of Systems Safety and Analysis
Office of Nuclear Reactor Regulation

4-1

Important-to-Safety Modifications

- Physical Modifications
  - Feed Pump Low Suction Pressure Trip Logic
  - Recirculation Runback on Feed Pump Trip
  - Main Turbine
- Operational Changes
  - Three Feed Pumps Instead of Two at Full Power (Continue to Operate with Three Condensate Pumps)
  - Increased Feedwater and Steam Flow to Support EPU

4-2

Scope of Planned Power Ascension Testing

- Measured Approach to Full EPU Power Level
  - Power Plateaus for Stabilization
  - Demonstration of Normal Control System Performance
  - Monitoring Instrumentation In Place
- No Licensee-Proposed Transient Testing
- Staff Identified Need for License Condition for Transient Testing

4-3

Operating Experience

- Favorable BWR Post-EPU Transient Response
- Predictable Response and Adequate Safety Margins Have Been Observed
- Exception: Dresden Vessel Overfill Event
  - Incomplete Modeling of Change from Two to Three Operating Feed Pumps for EPU
  - Transient Resulted in Vessel Over-Fill and Water Entry into HPCI Steam Lines
  - HPCI Steam Lines at Dresden Unusual; Separate and Lower than Main Steam Line Penetration into Vessel

4-4

VY Transient Testing Review

- Load-Rejection in 2004 Satisfies Many Objectives of Large Transient Test
  - About 80 Percent of CPPU Power Level (100 Percent of current licensed thermal power (CLTP))
  - Many EPU Mods Had Been Completed, Including Mods to Feedwater System and Main Turbine
- Significant Margin to Vessel Overfill Event
- Retains Substantial Turbine Bypass Capability
- Safety-Related System Performance Modeled in Safety Analyses -Adequate Margin Maintained

4-5

Vermont Yankee Transient Testing

- Condensate/Feedwater Interaction on a Loss of a Condensate Pump
  - Potential for Loss of All Feed Pumps due to New Common Low-Low Suction Pressure Trip
  - Outside Range of Previous Operating Experience
- Transient Testing License Condition Will Be Added to VY License
- Licensee Identified Calculational Error - Lower Margin than Previous Estimate
- Additional Modification for Direct Trip of a Feed Pump Proposed By Licensee and Currently Under Staff Review

4-6

Condensate Pump Trip Test

- Tests Integrated Response of Many Control Systems and Modifications, Including:
  - Recirculation Runback
  - Feedwater Level Control
  - Reactor Pressure Control
  - Feed Pump Suction Pressure Trip Logic
- Design Outcome is Continued Operation at Reduced Power
- Safety Benefit in Demonstrating Proper Transient Response and Maintenance of Normal Heat Removal (Defense-in-Depth) Justifies Operational Impact

4-7

Conclusion

- Limited Scope of Test Program Justified
  - Industry Operating Experience
  - VY Load Rejection Event
  - Acceptable Analytical Results and Safety Margins
  - Limited Scope of Modifications
- Transient Testing of Condensate/Feedwater Interaction Necessary
  - Affected By Modifications
  - Outside Bounds of Previous Experience

Crediting Containment Accident Pressure for NPSH

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Purpose

- To discuss NRC Staff review of the VY proposal to credit containment accident pressure in determining available net positive suction head (NPSH)

Regulations

- There is no regulation prohibiting credit for containment accident pressure in determining available NPSH for safety-related pumps

NRC Position

- NRC allows credit for containment accident pressure when:
  - a conservative analysis has demonstrated that this amount of pressure will be available for the postulated design basis accident; and
  - When examined from a broader perspective including design basis accidents, the level of risk is acceptable.

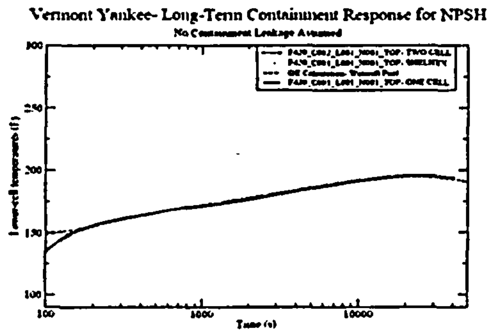
Postulated Accidents That May Require Credit

- Loss-of-Coolant Accident (LOCA)
- Anticipated Transients Without Scram (ATWS)

Calculating Containment Conditions

- SHEX computer code is used for LOCA and ATWS

NRC Calculation of Supp Pool Temp



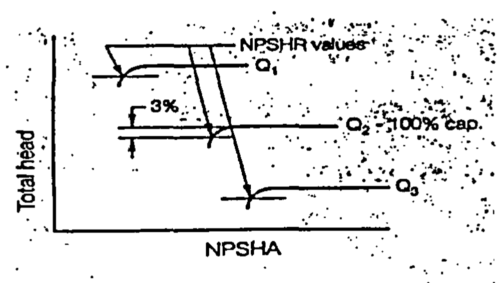
5-7

Calculating Containment Conditions

- GOTHIC 7.0 computer code is used for Appendix R and Station Blackout

5-8

Required NPSH Defintion



5-9

RG 1.82 Position on Required NPSH

- Credit may be taken for operation in cavitation provided:
  - Protypical pump tests are performed
  - Acceptable post-test examination

5-10

VY Required NPSH

- Based on pump vendor testing and expert judgment
- VY RHR and core spray pumps tested at reduced NPSH conditions - limited number of points.
- Additional data from other pump models
- Pump vendor states that pump design characteristics important to required NPSH are identical for non-VY pumps: specific speed, suction specific speed, blade inlet angle
- Pump affinity laws applied to adjust data
- Time at reduced NPSHR: pump vendor judgment

5-11

Conservatism

- VY Response to NRC Staff RAI:
  - "The more conservative initial conditions assumed in the design bases calculations are responsible for identification of the need to rely on containment accident pressure..."

Vermont Yankee TS Change No. 263, Supplement 8, July 2, 2004

5-12

LOCA Conservatism

- Reactor power 102% of licensed rated thermal power
- Decay heat at 2-sigma
- Decay heat bounds specific cycle
- Most conservative initial conditions
- All TS parameters at limiting value
- Worst single failure short-term: LPCI Loop Select failure results in pump runout flow

5-13

LOCA Conservatism

- Worst single failure long-term: RHR heat exchanger unavailable
- RHR flow through RHR HX minimized
- RHR service water flow (ultimate heat sink) through HX minimized
- Break flow heat and mass transfer with drywell atmosphere minimizes torus pressure
- NPSH calculation based on a suppression pool water volume less than predicted at time of peak temperature

5-14

LOCA Conservatism

- Value of ECCS strainer head loss used is greater than predicted
- No temperature correction made to required NPSH
- For the long-term, the distribution of debris on the one active CS strainer and one active RHR strainer will be the amount initially deposited in the short term + redistributed from inactive strainers + amount not removed in short term

5-15

LOCA Conservatism

- Strainer temperature for head loss calculations less than predicted suppression pool temperature
- RHR pump runout flow used for long-term LOCA
- Maximum service water temperature
- Continuous spray operation (torus and drywell)
- Peak initial suppression pool temperature (90 F)
- Operation of containment spray is assumed for the duration of NPSH calculation
- RHR pump flow assumed at runout (maximum) value for duration of LOCA - operator never throttles pump

5-16

LOCA Conservatism

- Cumulative conservatism due to the assumption that all conservatisms apply simultaneously

5-17

LOCA Conservatism

Single Failure Assumption	Peak Suppression Pool Temperature
With RHRHX Failure	195 °F
Without RHRHX Failure	169 °F

5-18

LOCA Conservatism

Input Parameter	Conservative Assumption	Anticipated Value	SP Estimated Temp Diff (F)
Decay Heat	Cycle Independent	Cycle Dependent	-2.0
Long-Term Vessel Recovery with Minimum SP Cooling	2 LPCI and 2 CS	1 CS	-8.0
RHR Flow (as it affects RHRHX performance) (gpm)	6,400	7,000	-0.6
RHRSW Flow (as it affects RHRHX Performance) (gpm)	2,700	4,000	-4.8

LOCA Conservatism

- Pre-EPU Peak SP Temperature = 182.6 °F
- Peak EPU SP Temperature = 194.7 °F
- Peak SP Temp - Sum of conservatisms in table
  194.7 °F - 15.4 °F = 179.3 °F
- Peak SP Temperature - Root mean square of conservatisms in table
  194.7 °F - 9.6 °F = 185.1 °F

Conservatism

- An analysis with realistic (nominal) assumptions shows that credit for containment accident pressure is not needed.

Containment Integrity

- VY design basis analyses assume containment integrity. Based on:
  - VY compliance with 10 CFR 50 Appendix J Leak testing
  - VY compliance with 10 CFR 50.55a inspections
- Walkdowns prior to containment closure
- VY containment is inerted

Peak Containment Pressure (psig)

Pre-CPPU	CPPU
41.6	41.8

Impact on Operator

- Credit for containment accident pressure does not change VY emergency operating procedures (EOPs). Containment pressure is currently a consideration for NPSH.
- No impact on operator

Conclusions

- Credit for containment accident pressure is determined conservatively.
- A more realistic but still conservative calculation would show that credit is not needed.
- Based on stringent testing requirements, inerting and VY EPU safety analyses, containment integrity is a reasonable assumption
- Credit for containment accident pressure has no impact on the operator
- Staff finds the VY credit for containment accident pressure acceptable

Containment Accident Pressure Credit NRC Staff Risk Evaluation

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Probabilistic Safety Assessment Branch
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Office of Nuclear Reactor Regulation

Presentation Outline

- Overview of risk evaluations to support non-risk-informed license amendment requests (LARs)
- NRC staff scoping risk evaluation of proposed containment overpressure (COP) credit
- Risk insights concerning defense-in-depth
- Risk insights concerning performance monitoring
- Conclusions

Non-Risk-Informed Submittals

- General references
  - COMSAJ-97-08, "Discussion on Safety and Compliance"
  - RIS 2001-02, "Guidance on Risk-Informed Decisionmaking in License Amendment Reviews"
  - Standard Review Plan (SRP), Chapter 19, Appendix D, "Use of Risk Information in Review of Non-Risk-Informed License Amendment Requests"
- The decision to submit a risk-informed LAR is voluntary on the part of the licensee

Process to Obtain Risk Information

- 10 CFR 2.102 gives NRC authority to require the submittal of information in connection with an LAR
- SRP 19, App. D provides the process to obtain risk information about a non-risk-informed LAR:
  - Staff requests risk information
  - If licensee declines, staff must show that the LAR raises questions about adequate protection of the public health and safety in order to require the licensee to provide risk information

Process to Obtain Risk Information (Con't.)

- Licensee needs to address the five key principles of risk-informed decisionmaking given in RG 1.174
- Licensee may decline to provide risk information, but could have its LAR denied
- Specific to extended power uprates (EPUs):
  - EPUs not submitted as risk-informed LARs
  - However, the staff expects licensees to submit a risk evaluation because a proposed EPU could create special circumstances that rebut the presumption of adequate protection from compliance with existing regulations and requirements
  - "Review Standard for Extended Power Uprates," RS-001, Rev. 0, Matrix 13

Five Key Principles in RG 1.174 and SRP 19

- The five key principles:
  - Proposed change meets the current regulations
  - Proposed change is consistent with the defense-in-depth philosophy
  - Proposed change maintains sufficient safety margins
  - Increases in risk should be small and consistent with the intent of the Commission's Safety Goal Policy Statement (51 FR 30028)
  - Impact of proposed change should be monitored using performance measurement strategies
- Acceptability of proposed change is determined by an integrated decisionmaking process

Risk Evaluation Chronology

9/10/03	Entergy submits EPU application
12/18/03	NRC staff sends Request for Additional Information (RAI): Question SPSB-7 asked about overpressure credit in the context of PRA operator actions
1/31/04	Entergy responded to the RAI (Supplement 5)
May 2004	Staff makes scoping risk evalution of overpressure credit
5/28/04	NRC staff sends RAI: Question SPSB-C-1 asked about the overall impact of the overpressure credit on risk
7/2/04	Entergy responded to the RAI (Supplement 8)
12/21/04	NRC staff sends RAI: Question SPSB-C-45 asked about thermal-hydraulic calculations that support PRA success criteria
2/24/05	Entergy responded to the RAI (Supplement 23)
7/19/05	Staff presentation to ACRS Subcommittee on Thermal Hydraulics concerning revision to RG 1.82; discusses initial staff risk evaluation. Subcommittee suggests that the risk evaluation be expanded to include more initiating events

6-7

Risk Evaluation Chronology (Con't.)

July - August 2005	Staff expands its risk evaluation by modifying SPAR models
9/8/05	Staff presentation to full ACRS Committee concerning revision to RG 1.82; discusses revised staff risk evaluation
9/10/05	ACRS letter on proposed revision to RG 1.82 recommends that it not be published for public comment without revisions
10/5/05	Staff requests Entergy to provide a risk evaluation of the overpressure credit that addresses the five key principles of risk-informed decisionmaking in RG 1.174
10/7/05	Staff presentation to full ACRS concerning proposed revision of RG 1.82; states intent to consider overpressure credit using risk-inform decisionmaking and make RG 1.82 a risk-informed regulatory guide
10/21/05	Staff completes draft Safety Evaluation; scope of risk evaluation based on NRR RS-001 and SRP 19, App. D
10/21/05	Entergy provides partial risk evaluation (Supplement 38)
10/26/05	Entergy completes risk evaluation (Supplement 39)
TBD	Staff to develop revised draft SE that includes review of Supplements 38 and 39

6-8

Staff Scoping Risk Evaluation

- Realistically conservative licensee thermal-hydraulic calculation indicates that containment overpressure credit is not required
- Staff risk evaluation assumes that core damage will occur only if all of the following occur:
  - Reactor coolant is discharged to the suppression pool
  - Low pressure core injection (LPCI) or core spray (CS) is required to provide reactor inventory control or decay heat removal
  - Containment integrity is lost (loss of overpressure, which leads to inadequate NPSH)
  - Operator does not initiate suppression pool cooling within four hours

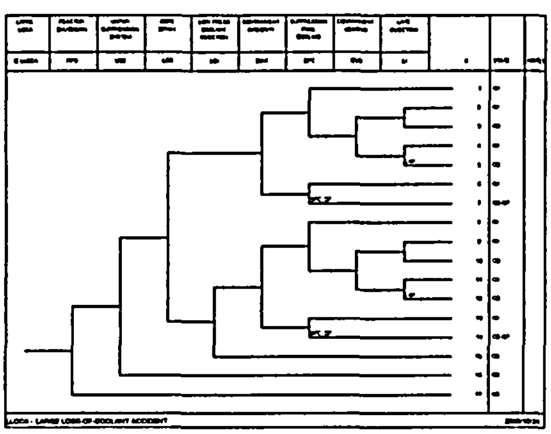
6-9

Scoping Risk Model

- Modification of the Standardized Plant Analysis of Risk (SPAR) models developed by the Office of Research (RES). SPAR models are the basis of:
  - Significance Determination Process (SDP)
  - Accident Sequence Precursor (ASP) program
- Considered:
  - 11 transient initators
  - 5 LOCA initiators (including ISLOCAs)
  - Special sequence types
    - Station blackout (SBO)
    - Stuck-open relief valve (SORV)
    - Anticipated transients without scram (ATWS)

6-10

Scoping Risk Model (Con't.)



6-11

Scoping Risk Model (Con't.)

- Data to quantify loss of containment integrity (including pre-existing undetected leaks and containment isolation failures) obtained from:
  - Licensee's recent submittal for a one-time ILRT extension to 15 years
  - Office of Research (RES)
- Human failure event (failure to initiate suppression pool cooling within four hours):
  - Cognitive Errors: EPRI Cause-Based Decision Tree Method (CBDTM)
  - Action Errors: NUREG/CR-1278, A Technique for Human Error Rate Prediction (THERP)

6-12

Scoping Risk Model (Con't.)

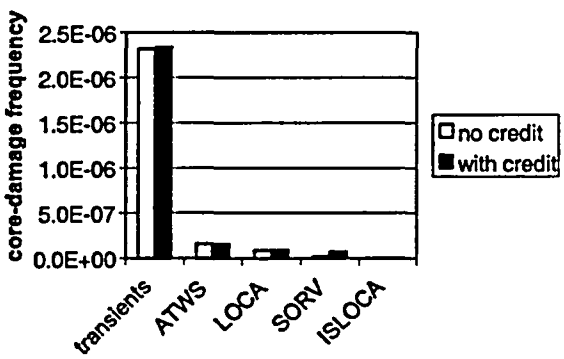
- Quantification method:
  - Truncation limit: 10^{-12} per year
  - 5000 Monte Carlo samples for parametric uncertainty analysis
  - Minimal cut sets regenerated for each sensitivity analysis case
- Uncertainty analysis:
  - Parametric uncertainties
  - Modeling uncertainties
    - Containment leak size
    - Main steam isolation valve (MSIV) success criterion
    - Human reliability analysis methods

Results of the Analysis

	mean	5th percentile	95th percentile
CDF for no overpressure credit	2.6E-06	2.5E-07	8.9E-06
CDF with COP credit	2.6E-06	2.5E-07	8.9E-06
change in CDF due to COP credit	6.2E-08 2.4%	2.6E-10	2.5E-07

- Very small change in core-damage frequency (CDF) using the risk acceptance guidelines in RG 1.174

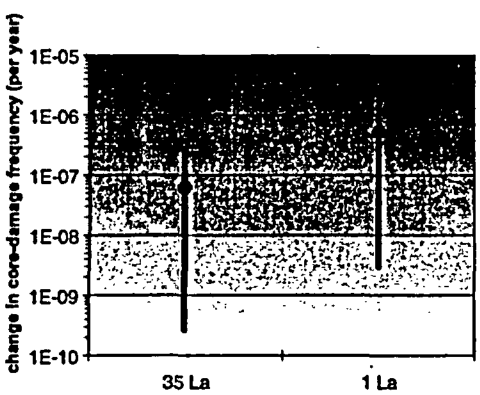
Contributions to Core-Damage Frequency



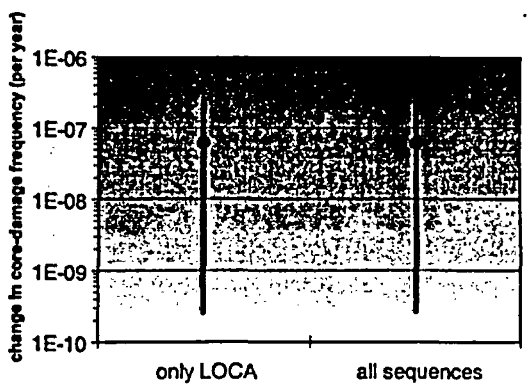
Importance Measures

Event	Fussell-Vesely Importance	Risk Achievement Worth
Pre-existing, undetected containment leakage	2.50E-02	2.8
Operator error	8.90E-03	11.3
Containment isolation failure	7.40E-04	2.7
MSIV failures	1.30E-06	1.02

Sensitivity to Containment Leak Size



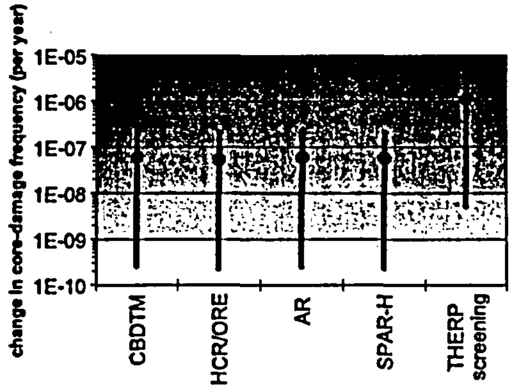
Sensitivity to MSIV Success Criterion



Sensitivity to Human Reliability Analysis

- Alternative methodologies:
  - HCR/ORE: Human Cognitive Reliability/Operator Reactor Experiments, EPRI NP-7183-SL (1990)
  - AR: Annunciator Response, NUREG/CR-4772 (1987)
  - SPAR-H: SPAR-H Human Reliability Analysis Method, NUREG/CR-6883 (2005)
  - THERP: Technique for Human Error Rate Prediction, NUREG/CR-1278 (1983); used for initial screening analysis

Sensitivity to HRA Method



Risk Insight: Impact on Defense-in-Depth

- PRA can provide insights about how the proposed COP credit affects the balance between accident prevention and mitigation
- Consideration of this balance is important in weighing the necessity and sufficiency of defense-in-depth measures
- Staff considered how the proposed COP credit would affect the conditional containment failure probability (CCFP) in order to evaluate the balance between accident prevention and mitigation

Approximate Impact on CCFP

$$CCFP \equiv \frac{\text{accident release frequency}}{\text{core damage frequency}}$$

R_{CCFP} = fractional change in CCFP

R_{CDF} = fractional change in CDF

Since core-damage accidents caused by loss of containment integrity will cause some form of release, it can be shown that:

$$R_{CCFP} = \frac{1-CCFP}{CCFP} \times \frac{R_{CDF}}{1+R_{CDF}}$$

Approximate Impact on CCFP (Con't.)

NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," Table 12.7 indicates that the CCFP for a BWR plant with a Mark I containment is generically about 0.6:

$$R_{CCFP} = \frac{1-0.6}{0.6} \times \frac{0.024}{1+0.024} = 0.016 = 1.6\%$$

This result suggests that the proposed COP credit does not significantly change the existing balance between accident prevention and mitigation.

SRP 19 Defense-in-Depth Objectives

- The LAR does not result in a significant increase in the existing challenges to the integrity of barriers.
- The LAR does not significantly change the failure probability of any individual barrier.
- The LAR does not introduce new or additional failure dependencies among barriers that significantly increase the likelihood of failure compared to the existing conditions.
- The overall redundancy and diversity among barriers is sufficient to ensure compatibility with the risk acceptance guidelines.

SRP 19 Defense-in-Depth Evaluation

- The proposed COP credit has no effect on LOCA or transient-induced SORV frequencies because it does not affect normal plant operating conditions.
- The proposed COP credit has no effect on the probability of containment failure because it does not affect normal plant operating conditions.
- Under the assumptions of the design-basis accident (DBA) analysis, the proposed COP credit introduces a dependency between the fuel and containment barriers; however, this does not appear to be probabilistically significant.

6-25

SRP 19 Defense-in-Depth Evaluation (Con't.)

- Realistically conservative analyses indicate that no COP credit is needed. Even if the COP credit is presumed to change PRA success criteria, then:
  - There must be at least three failures to cause a core-damage accident:
    - LOCA (or SORV, which requires multiple failures)
    - Loss of containment integrity
    - Loss of suppresion pool cooling
  - The mean change in CDF is very small and meets the RG 1.174 risk acceptance guidelines
  - Results are robust in terms of uncertainties and sensitivities to key modeling parameters and assumptions

6-26

SRP 19 Defense-in-Depth Evaluation (Con't.)

- The scoping risk evaluation, based on the assumption that the proposed COP credit changes the PRA success criteria, indicates that the proposed COP credit does not significantly change the CCFP. Hence, it does not significantly change the existing balance between accident prevention and mitigation.
- Therefore, the proposed COP credit meets the four defense-in-depth objectives in SRP 19.

6-27

ACRS Comments on Defense-in-Depth

- ACRS letter of May 19, 1999
  - Expressed concerns about "arbitrary appeals to defense in depth" to avoid making changes to regulations and regulatory practices that seem appropriate in light of PRA results
  - Expressed the notion that there should be an inverse correlation between the uncertainty in PRA results and the extent to which defense in depth is applied
- Position reiterated in joint ACNW/ACRS letter of May 25, 2000

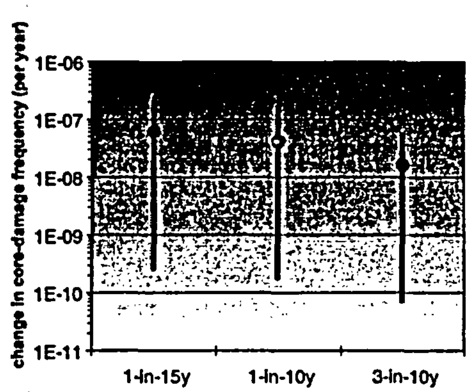
6-28

Risk Insight: Performance Monitoring

- The probability of pre-existing, undetected containment leaks used in the scoping risk evaluation is conservative:
  - The VY containment is inerted with nitrogen
  - Probability was estimated from results of Type A integrated leak rate tests (ILRTs) for the entire U.S. commercial nuclear industry
  - More realistic approach would be to reduce this probability since inerting provides a continual means of detecting loss of containment integrity
- A sensitivity study was performed to assess the impact of the ILRT frequency on the change in CDF

6-29

Sensitivity to ILRT Frequency



6-30

Conclusions

- Draft staff safety evaluation (SE) is based on consideration of adequate protection
- Staff will revise its SE after considering latest licensee supplements
- Staff scoping risk evaluation indicates that the proposed COP credit:
  - Has very small risk, even after considering parametric and modeling uncertainties
  - Does not significantly change the existing balance between accident prevention and mitigation
  - Meets the defense-in-depth objectives in SRP 19

Engineering Inspection

Larry Doerflein
Chief, Engineering Branch 2
Division of Reactor Safety
Region I

Agenda

- Introduction - Larry Doerflein
- Inspection Background - Larry Doerflein
- Engineering Inspection - Jeff Jacobson
- Followup of Inspection Issues - Larry Doerflein
- Impact on EPU Amendment Review - Rick Ennis
- Questions and Comments

Inspection Background

- Biennial Safety System Design and Performance Capability Inspection Scheduled
- Request for Independent Safety Assessment
- Conditions Different than Maine Yankee
- New Inspection Procedure
- Team Independence
- Vermont State Nuclear Engineer Participation

Vermont Yankee Engineering Inspection

Jeff Jacobson
Team Leader
Vermont Yankee Engineering Inspection

Inspection Background

- VY inspection was responsive to the Vermont Public Service Board request to conduct an independent assessment and provide the inspection results to the ACRS for review
- VY inspection was part of a pilot program developed to improve the effectiveness of NRC engineering/design inspections
- VY inspection was the first of four pilot inspections
- The inspection involved about 900 hours of direct inspection versus 475 for a normal engineering team inspection

Inspection Staffing and Scope

- The inspection team included an NRR team leader, four NRC regional inspectors, and three highly qualified independent contractors
- All team members were independent of any recent oversight responsibilities of VY
- The inspection team focused on components and operator actions that represented high risk and had the lowest relative safety margins
- Low margin areas were identified in part by consultation with NRR technical staff

7-6

Inspection Scope (continued)

- Forty five components, operator actions, and operating experience samples were reviewed in detail
- The components reviewed were part of the following plant systems
  - On-site and off-site electrical systems
  - Reactor core isolation cooling system
  - Residual heat removal system
  - Safety relief valves
  - Reactor feedwater and condensate systems
  - Other risk significant systems

7-7

Pilot Inspection Areas of Review

- Visual signs of degradation, installation errors, interference issues, environmental concerns
- Design and licensing basis documentation
- Review of design assumptions, system interfaces, failure modes
- Component history including maintenance, corrective action, and testing records
- Operating procedures
- Focus on functionality of equipment

7-8

Additional Reviews Conducted Specifically for VY Inspection

- Comparison against current and uprated power levels
- Assessment of design control processes applied to power uprate

7-9

Inspection Results

- Eight findings of very low risk significance (Green)
- Findings did not result in system inoperability either as compared to current or uprated power levels
- Findings were not indicative of any programmatic breakdown
- The inspection approach used during the four pilot inspections was determined to be more effective than the system based vertical slice approach that is part of the current baseline inspection program
- Plans are to adopt this low margin inspection approach into the baseline engineering inspection program beginning 1/1/2006

7-10

Inspection Findings

- Capability of Vernon Hydro-electric station to supply power to VY in event of a regional blackout*
- Adequacy of procedure used to monitor operability of offsite power
- Lack of degraded voltage analysis
- Reactor Core Isolation Cooling pressure control valve - reliance on instrument air
- Reactor Core Isolation Cooling pressure control valve - automatic operating mode inoperable

* EPU related

7-11

Inspection Findings (continued)

- Non-conservative input for condensate storage tank temperature used in transient analysis*
- Safe shutdown analysis used incorrect time for initiating reactor core isolation system from alternate control panel*
- Insufficient acceptance criteria and unverified diagnostic equipment used in motor operated valve testing*
- In addition to 8 findings, one unresolved item (URI) - ungrounded 480 VAC electrical system

* EPU related

7-12

Required Corrective Actions

- The licensee is required to enter all the identified inspection findings into its corrective action program
- Corrective actions for all eight findings will be reviewed as part of the NRC's baseline inspection program -detail to be provided by Larry Doerflien
- In addition, corrective actions to the four findings that relate to areas covered by the NRC's power uprate were reviewed by the NRC's technical staff as part of the licensee's overall power uprate submittal - detail to be provided by Rick Ennis

7-13

Followup of Inspection Issues

Larry Doerflein
Chief, Engineering Branch 2
Division of Reactor Safety
Region I

7-14

Status of Inspection Issues

- All Eight Inspections Findings Received Followup
- Inspection completed
  - IR 2005-002
    - RCIC startup time line
    - Procedure for assessing operability of off-site power
  - IR 2005-004
    - Degraded Relay Setpoint Calculations
    - CST Temperature
  - IR 2005-006
    - Availability of Power from Vernon Hydro Station
    - MOV Testing

7-15

Status of Inspection Issues

- More Inspection Needed
  - Design of RCIC pressure control valve
  - Non-conforming operation of RCIC pressure control valve
- Other
  - URI on Ungrounded 480V System - Task Interface Agreement (TIA)

7-16

Engineering Inspection Impact on EPU Review

Rick Ennis
Senior Project Manager
Divsion of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

7-17

Findings Related to EPU Review

- The findings that impacted the EPU review were:
  - Station Blackout
  - Appendix R Timeline for Reactor Core Isolation Cooling System (RCIC) Initiation
  - Periodic Testing of Motor-Operated Valves (MOVs)
  - Condensate Storage Tank (CST) Temperature

7-18

Station Blackout (SBO)

- Finding impacts Safety Evaluation Section 2.3.5, "Station Blackout"
- Coping analysis performed to address finding (Supplement 25 dated 3/24/05)
- Review of coping analysis determined for 2-hour coping period:
  - Adequate condensate inventory;
  - Adequate battery capacity;
  - Equipment operability with loss of ventilation;
  - Containment isolation maintained; and
  - NPSH met without crediting containment accident pressure.
- Staff concluded VY will meet SBO requirements under EPU conditions

7-19

Appendix R Timeline for RCIC Initiation

- Finding impacts Safety Evaluation Section 2.11, "Human Performance"
- Time to core uncovery:
  - 25.3 minutes (current power level)
  - 21.3 minutes (EPU level)
- Time to place RCIC in service for Appendix R:
  - 15 minutes (1999 analysis)
  - 21 minutes (inspection team finding)
- Procedure revised to address finding.
- Results of timed operator crew walkthroughs of revised procedure submitted in Supplement 22 dated 12/8/04:
  - Times ranged from about 12 to 15 minutes
  - Average time about 13.5 minutes
- Staff concluded that sufficient margin exists to place RCIC in service during an Appendix R event under EPU conditions

7-20

Periodic Testing of MOVs

- Finding impacts Safety Evaluation Section 2.2.4, "Safety-Related Valves and Pumps"
- Licensee did not manage commitments and conditions in SE for GL 96-05 MOV Periodic Verification Program
- Supplement 16 dated 9/30/04 committed to revise MOV Periodic Verification Program
- Supplement 32 dated 9/10/05 stated commitment is complete
- Staff concluded safety-related valves will continue to meet applicable requirements following EPU implementation

7-21

CST Temperature

- Finding impacts Safety Evaluation Section 2.6.5, "Containment Heat Removal"
- Supplement 18, dated 10/5/05 revised ATWS analyses for EPU
- Increase in CST temperature increased suppression pool temperature from 190F to 190.5F
- Peak suppression pool temperature for limiting event (LOCA) is 194.7F
- Staff concluded effect of CST temperature change is acceptable since limiting temperature will not be exceeded

7-22

Conclusions

- Licensee submitted supplements to EPU application to address all 4 findings
- NRC staff has reviewed information and concludes the issues have been adequately addressed

7-23

Engineering Inspection Summary

- Engineering inspection was responsive to the Vermont Public Service Board request (hours spent, scope, independence)
- Inspection approach considerd an improvement over vertical slice approach
- All of the inspection findings were of low safety significance
- All inspection findings have received followup inspection for corrective actions
- Findings impacting the EPU have been adequately resolved as addressed in the NRC staff Safety Evaluation

ACRS Thermal-Hydraulic Subcommittee

Vermont Yankee Extended Power Uprate

Containment Overpressure Credit

November 16, 2005

Bill Sherman – VT Dept of Public Service

1

Vermont Appreciates

- The opportunity to speak today on Containment Overpressure Credit
- We presented on this subject:
  T-H Subcommittee – July 19, 2005
  Full Committee – September 8, 2005
- We have high confidence in the ACRS to consider this issue and to assist in resolving our concern.

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Brief History

- We question the desirability of relying on containment pressure for the adequacy of emergency cooling pumps.
- We found the staff not following its own guidance in this area.
- We initiated an Atomic Safety and Licensing Board proceeding.
- We continue to have questions.

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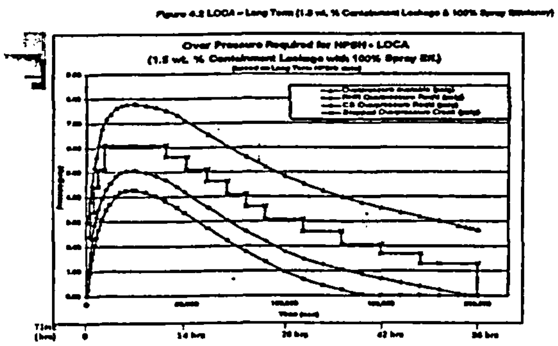
ACRS Letter September 20, 2005

- No practical alternatives that can eliminate the need for such credit
- Positive means for indication of containment integrity
- The time intervals for such credit should be limited to a few hours, commensurate with the demonstrated capability of equipment to perform its intended functions during this time period

4



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5. Double length of refueling outage/ alternative over two outages

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Practical Alternatives 2

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- Safety issues shouldn't be cost driven
- There is significant economic value to Entergy from the proposed power uprate

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Other Comments Re: ACRS Letter

- Positive Indication Containment Integrity: Inerting, *per se*, is not effective means – a feed and bleed system
- Drywell at positive pressure but not torus
- Demonstrated capability for time period: Containment tested for 24 hours not 56 hours, and not for ten years

8

Summary Re: ACRS Letter

- There are practical alternatives
- There is not full positive indication of containment integrity
- Containment integrity has not been demonstrated for the credited time period

9

Staff Response to ACRS Letter

- On Oct 7, 2005, Dr. Brian Sheron proposed a risk based (RG 1.174) approach in lieu of implementing practical alternatives
- We believe this approach may have promise
- Entergy's PSA Supplements (#38-10/21/05, #39-10/26/05) are not sufficient to accomplish Dr. Sheron's proposal

10

Entergy's Risk Evaluation

- 10/21 – An evaluation of the 5 elements from RG 1.174
- 10/26 PSA – New top event: Primary Containment Integrity
- CDF difference between containment pressure available and not available

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VY Risk Evaluation: Items to Consider – RG 1.174 Elements

- RG 1.174 – "The proposed change is consistent with defense-in-depth philosophy"

The proposed change makes the fuel cladding barrier dependent on the containment barrier, a significant modification of defense-in-depth philosophy

12

VY Risk Evaluation: Items to Consider – RG 1.174 Elements

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14

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16

VY Risk Evaluation: Items to Consider – Analysis Method 1

- **Method presented:**
  CDF difference between (a) containment pressure available and (b) not available
- **Method desired:**
- CDF difference between (a) the NPSH failure of cooling pumps with no use of containment overpressure and (b) the NPSH failure of cooling pumps with use of containment overpressure

VY Risk Evaluation: Items to Consider – Analysis Method 2

- The *Desired Method* would:

1. Capture the loss of NPSH margin given up by crediting overpressure
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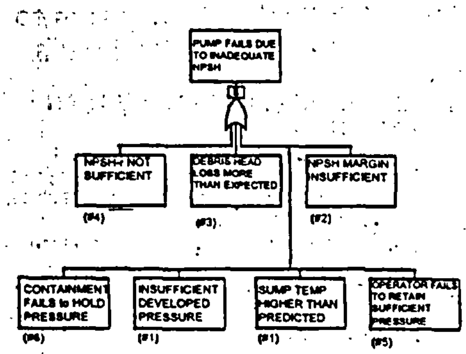

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1. Staff SER discusses "reduced NPSH-r"
2. NPSH-r used somewhere between NPSH-3% and NPSH-6% - in cavitation
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21

VY Risk Evaluation: Items to Consider – Analysis Method 5

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4. RG 1.82, Sec. 2.1.1.3 States: Pumps in cavitation should have performance tests at least as long as the pumps operate in cavitation.
5. Summary – There is some non-trivial probability that the NPSH-r is not sufficient

22

VY Risk Evaluation: Items to Consider – Analysis Method 6

- DEBRIS HEAD LOSS MORE THAN EXPECTED

1. VY Paint Chip Assumption – Assumes all unqualified paint fails; Assumes all failed paint is transported to Torus; assumes *NO* paint chips deposited on the strainers
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VY Risk Evaluation: Items to Consider – Analysis Method 8

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25

VY Risk Evaluation: Items to Consider – Analysis Method 9

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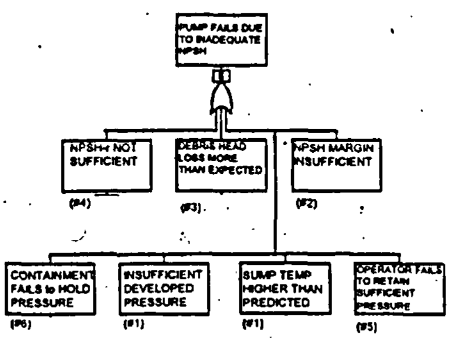

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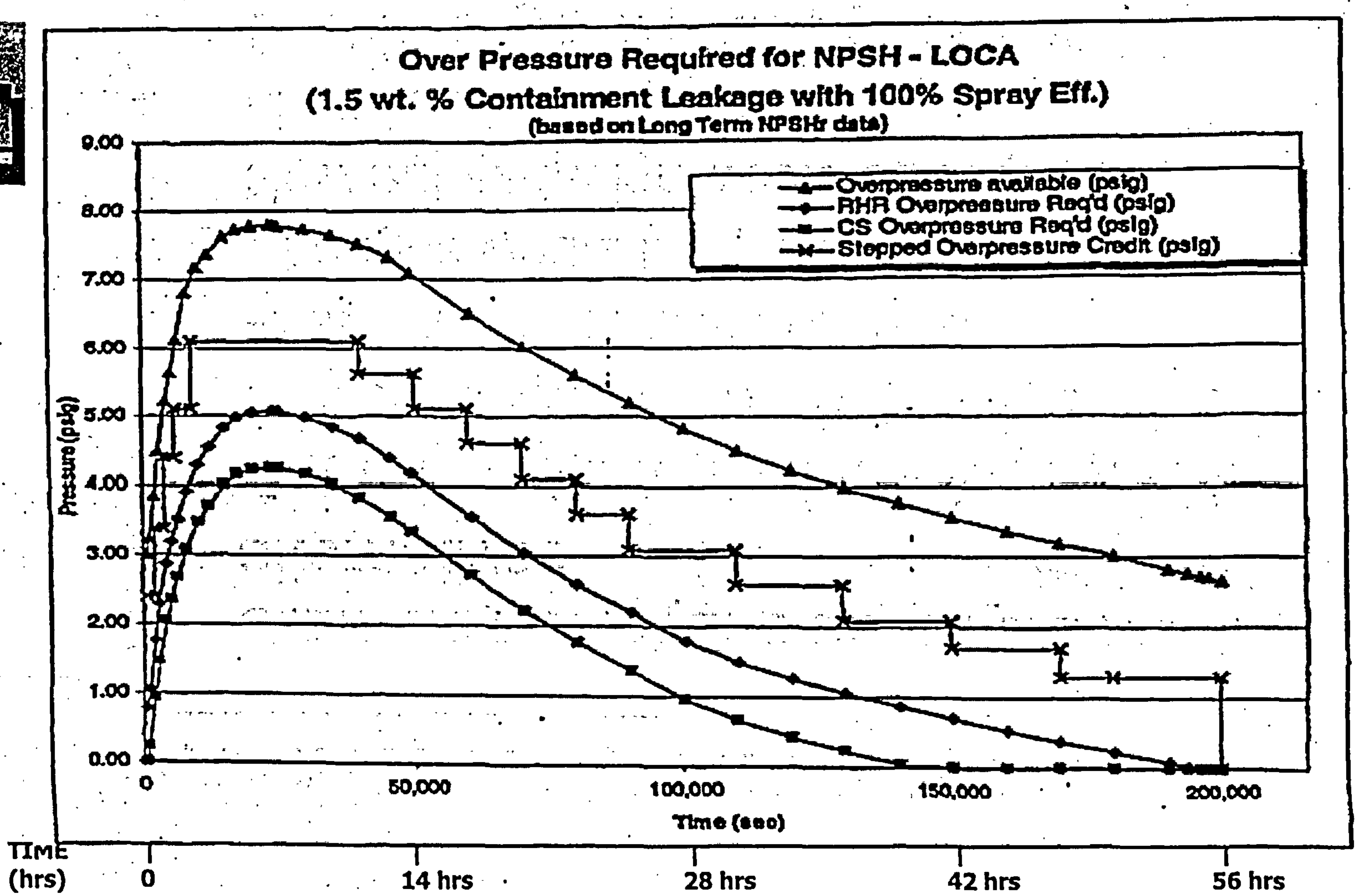
Figure 4.2 LOCA – Long Term (1.5 wt. % Containment Leakage & 100% Spray Efficiency)



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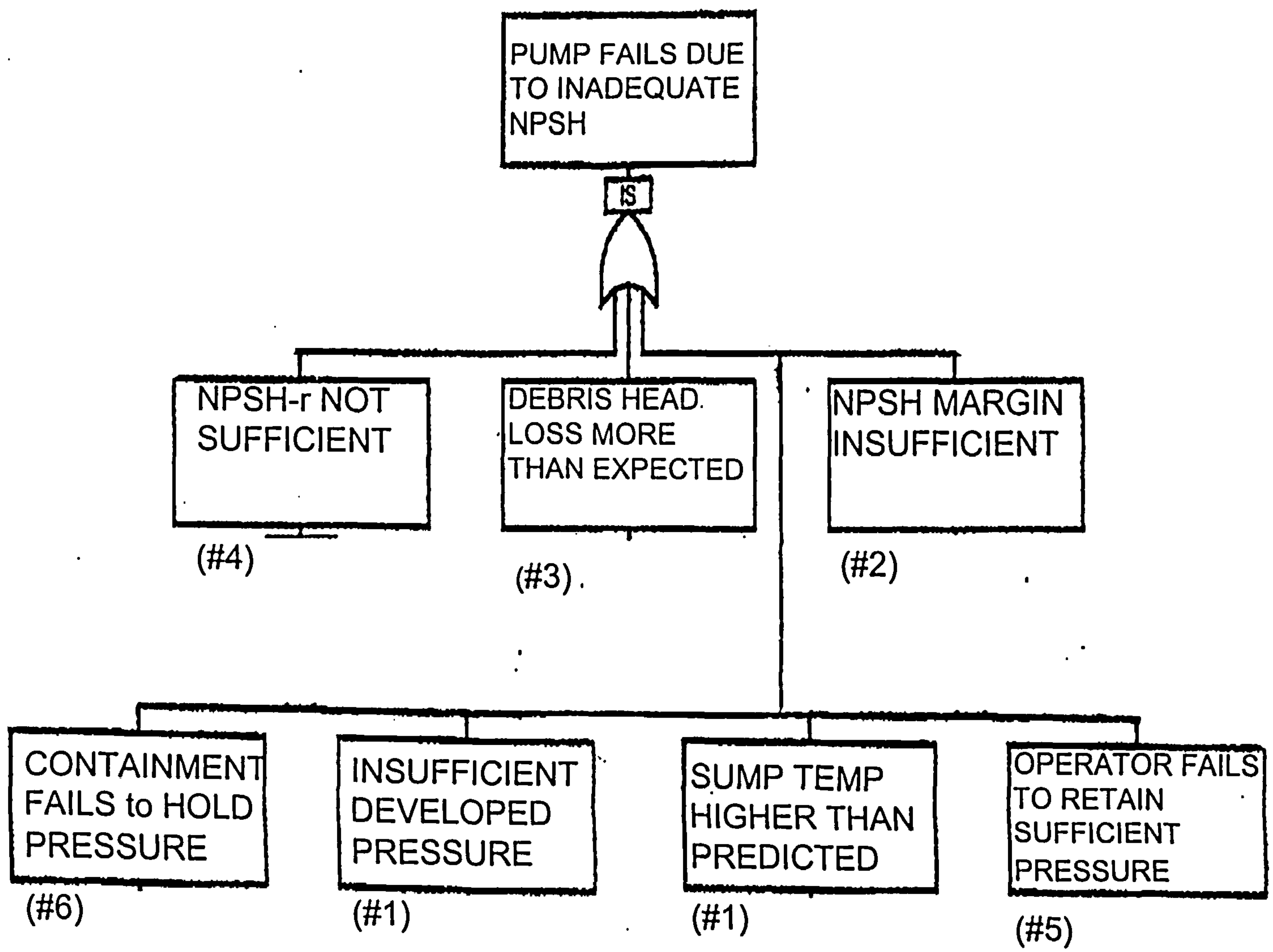

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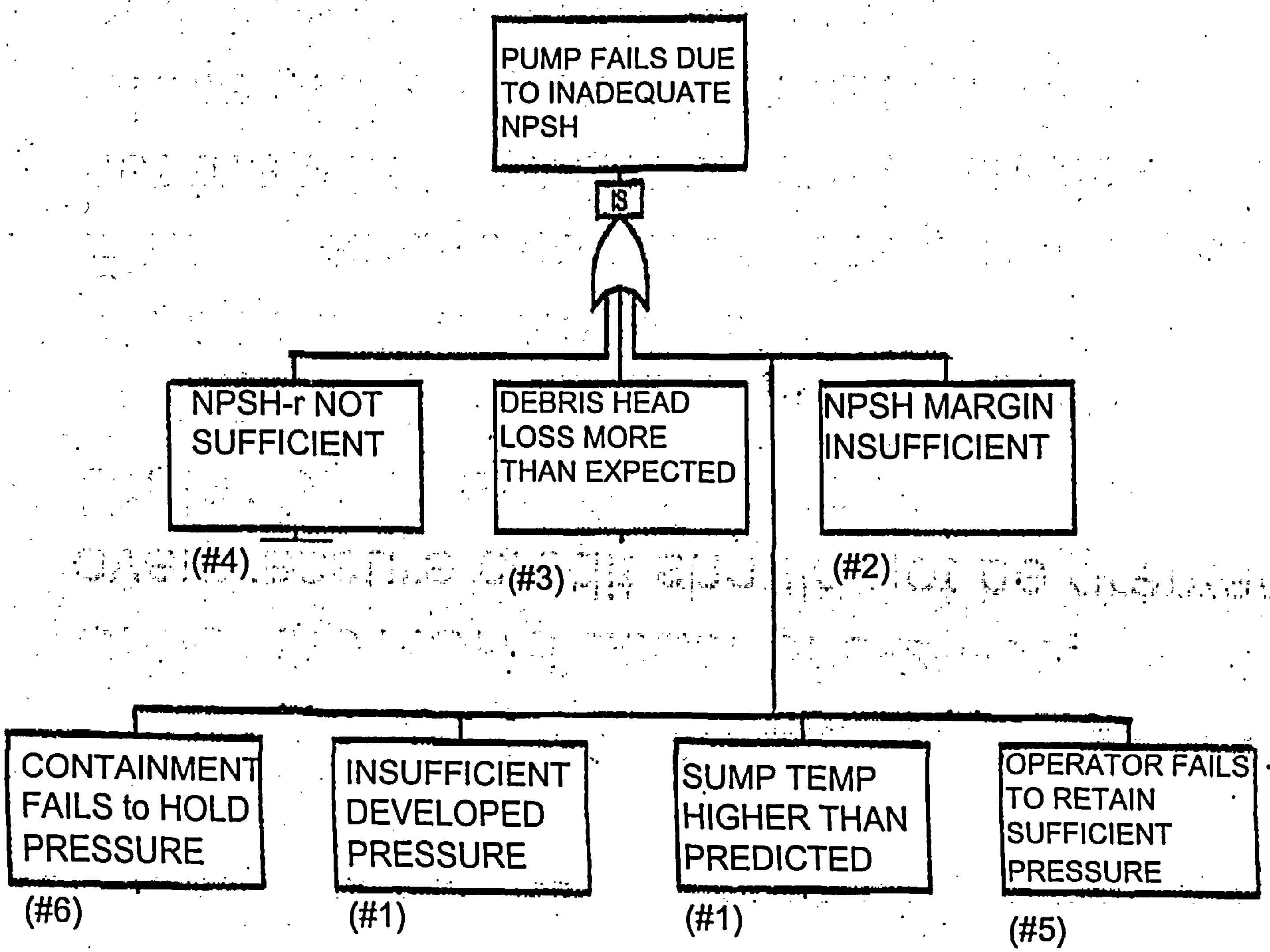
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Containment Overpressure

Brian Hobbs
EPU Engineering Supervisor

Containment Overpressure

Presentation Overview

- Regulatory/Industry Background
- Basis for Request
- Requested Overpressure Credit
- Risk Assessment of Crediting Overpressure

Containment Overpressure
Regulatory/Industry Background

- 25 Plants Credit Overpressure in Licensing Basis
  - Includes 7 BWR Extended Power Uprates
- Regulatory Guide 1.82 Rev. 3
  - Defines Basis for Crediting Overpressure
- VYNPS Analysis Conforms to RG 1.82 Rev. 3 COP Basis

Containment Overpressure

Regulatory/Industry Background (cont.)

TABLE 1: BWR's With Mark I Containments Crediting Overpressure

Plant	**Max. Pressure Credited (psig)**	**Duration of Credit (hours)**
Duane Arnold	7.3	36
Dresden	6.6	>50
Peach Bottom	6.1	78
Pilgrim	5.0	48
Quad Cities	6.6	>50
VYNPS (requested)	6.1	56

Containment Overpressure

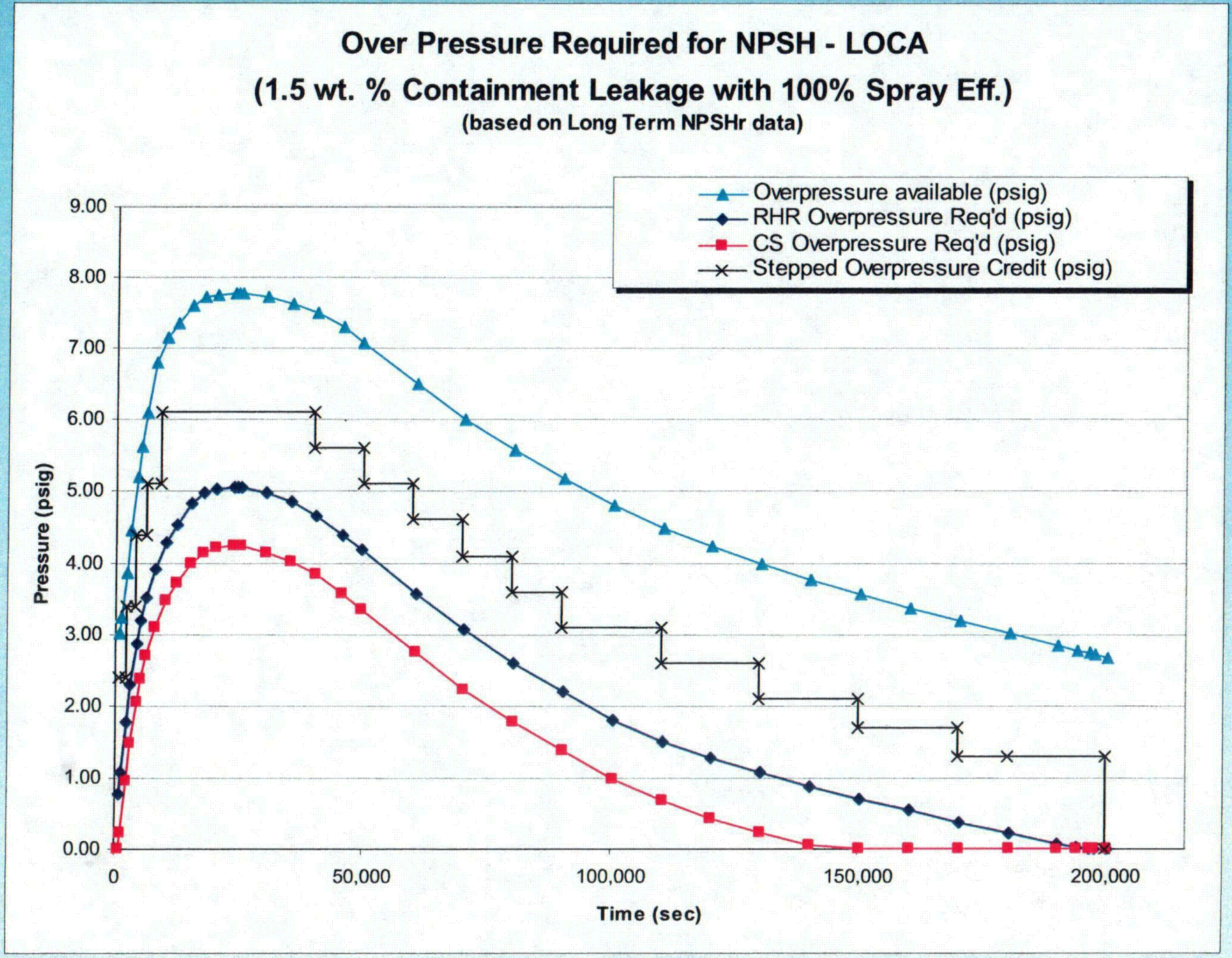
Basis for Request

- EPU Increases Decay Heat
- Pool Temperature Increases ~12°F from Current Analysis to EPU
- Peak EPU DBA LOCA Temperature ≅ 195°F
- Low Pressure ECCS Pumps $NPSH_A < NPSH_R$
  - RHR Pumps
  - Core Spray Pumps

Containment Overpressure

Requested Credit

Figure 1: Containment Overpressure Required for VYNPS Large LOCA



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Containment Overpressure

Risk Assessment

- Regulatory Guide 1.174 Elements
  1. Meets Current Regulations
  2. Provides Defense-In-Depth
  3. Maintains Safety Margins
  4. Results In Small Risk Increase
  5. Performs As-Assumed Based on Monitoring

Containment Overpressure
Risk Assessment

- VYNPS COP Credit Defense-In-Depth
  - Conservative Design & Construction
    - Meets Design Criteria for Redundancy, Diversity & Independence
    - Single Failure
      - Containment As The Single Failure Would Preclude Need for COP

Containment Overpressure
Risk Assessment

- VYNPS COP Credit Defense-In-Depth (cont.)
  - Conservative Design Basis Assumptions
    - Maximum Initial SP Temperature, Minimum Level
    - Maximum Reactor Power, Core Decay Heat
    - Maximum Initial SW Temperature, Minimum Flow
    - Minimum Heat Exchanger Effectiveness

Containment Overpressure
Risk Assessment

- Realistic Analysis Would Not Require COP Credit
  - Sensitivity of Input Assumptions vs. COP Required Shown in Table 2

Containment Overpressure
Risk Assessment

Table 2: Sensitivity of Input Assumptions vs. COP Required

	Inputs				Results		
CASE	Single Failure	T_{sw} (°F)	Initial T_{pool} (°F)	Other Inputs	Peak T_{pool} (°F)	RHR COP Req'd ?	CS COP Req'd ?
1	RHR HX	85	90	Design Basis	195	Yes	Yes
2	Containment	85	90	Design Basis	169	No	No
3	RHR HX	85	90	Nominal	185	No	No
4	RHR HX	80	85	Nominal	180	No	No
5	RHR HX	55	78	Nominal	166	No	No

Containment Overpressure
Risk Assessment

- VYNPS COP Credit Defense-In-Depth
  - Credits Existing Condition
  - Barrier Effectiveness is Maintained
    - No New Accidents
    - Failure Probability
    - Failure Dependencies

Containment Overpressure

Risk Assessment

- VYNPS COP Credit Defense-In-Depth (cont.)
  - Preserves Defenses Against Human Error:
    - No Additional Operator Actions
    - No Changes to Operator Actions
    - No Changes to Existing Operating Procedures

Containment Overpressure

Risk Assessment

- VYNPS COP Credit Maintains Adequate Safety Margin
  - Current Applicable Codes & Standards Continue to be Met
  - Bounding Design Basis Analysis Assumptions Include Margin (Conservatism)
  - Substantial Margin to Fission Product Barrier Limits is Maintained

Containment Overpressure

Risk Assessment

- VYNPS COP Credit Risk Assessment
  - PSA Model Was Applied to Evaluate ΔRisk When COP Is Needed for Adequate NPSH
  - Results: Very Small Change in Risk
    - ΔCDF = 5.8 E-7/ry
    - ΔLERF = 4.5 E-8/ry

Containment Overpressure

Risk Assessment

- VYNPS COP Credit Risk Assessment (cont.)
  - COP Risk Assessment Actions
    - Incorporate Containment Leakage Probability into the Level 1 PSA Model
      - New Fault Tree Top Event: Primary Containment Integrity
    - Incorporate COP Impact on NPSH for Event Trees
    - Perform Uncertainty Evaluation
    - Characterize Risk Assessment Impacts

Containment Overpressure

Risk Assessment

- Monitoring VYNPS COP Credit
  - Containment Integrity Monitoring Methods:
    - Containment Leak Rate Testing
    - Inservice Inspection
    - Surveillances & Operator Indications
  - Allowable Primary Containment Leakage
    - L_a = 0.8 wt% per day (Technical Specifications)
  - 27*L_a Containment Leakage Rate Would Still Maintain Adequate Overpressure

Containment Overpressure
Risk Assessment

- Monitoring VYNPS COP Credit (cont.)
  - DW Pressure 1.7 psi > Suppression Pool
    - Technical Specification Requirement
    - Control Room Alarm On Decreasing dP
    - If Not Met, Cold Shutdown in < 24 Hours
- Containment Inerted With Nitrogen
  - Consumption Monitored

Containment Overpressure
Conclusions

Entergy

- Overpressure Credit Request:
  - Meets Applicable Regulatory Requirements
  - Results in Very Small Change in Risk
  - Realistic Assumptions Preclude Need for Overpressure

NRC Engineering Inspection

John Dreyfuss
Director – Engineering

NRC Engineering Inspection

- Inspection Scope
- Results – Summary and Findings
- Corrective Actions
- EPU Impact

NRC Engineering Inspection

- EPU Related Issues
  - Appendix R Operator Timeline
  - MOV Periodic Testing
  - Condensate Storage Tank Temperature
  - Station Blackout

Crediting Containment Accident Pressure for NPSH

Richard Lobel
Senior Reactor Systems Engineer
Probabilistic Safety Assessment Branch
Division of Systems Safety and Analysis
Office of Nuclear Reactor Regulation

Purpose

- To discuss NRC Staff review of the VY proposal to credit containment accident pressure in determining available net positive suction head (NPSH)

Regulations

- There is no regulation prohibiting credit for containment accident pressure in determining available NPSH for safety-related pumps

5-3

NRC Position

- NRC allows credit for containment accident pressure when:
  - a conservative analysis has demonstrated that this amount of pressure will be available for the postulated design basis accident; and
  - When examined from a broader perspective including design basis accidents, the level of risk is acceptable.

5-4

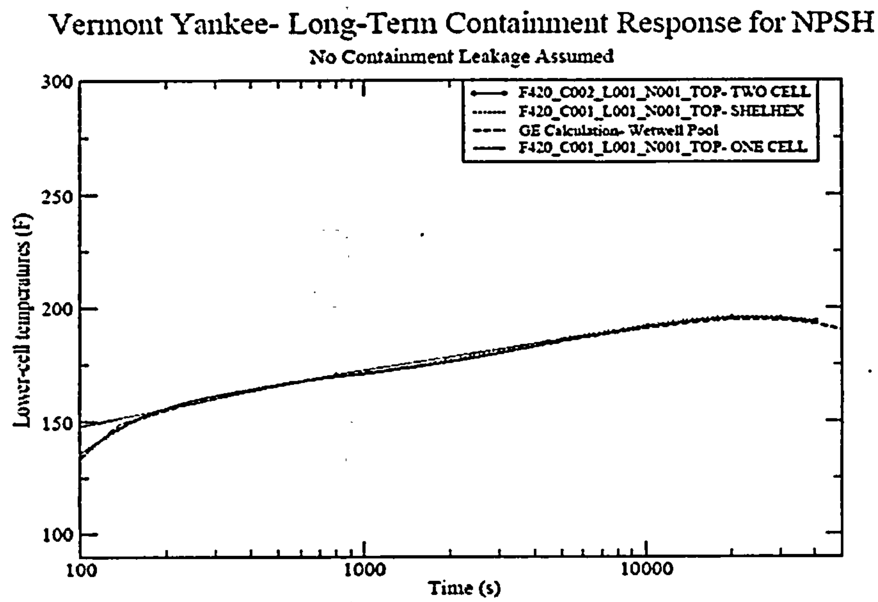
Postulated Accidents That May Require Credit

- Loss-of-Coolant Accident (LOCA)
- Anticipated Transients Without Scram (ATWS)

Calculating Containment Conditions

- SHEX computer code is used for LOCA and ATWS

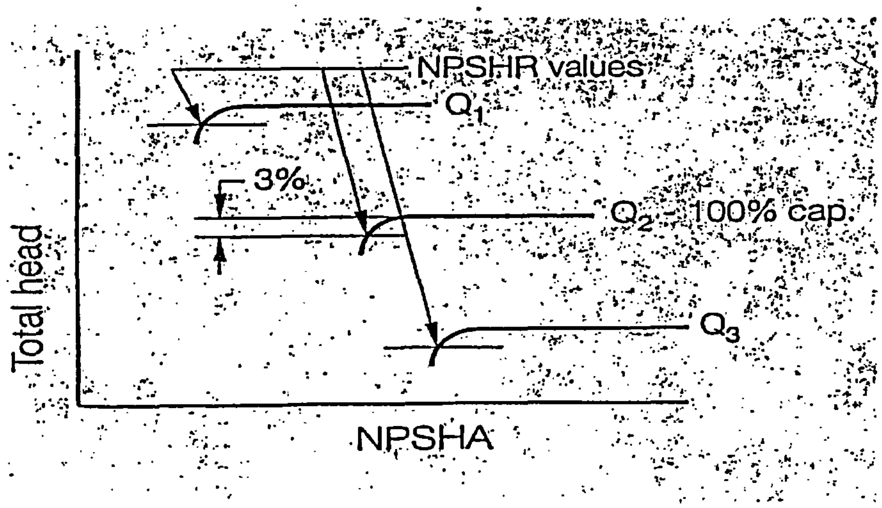
NRC Calculation of Supp Pool Temp



Calculating Containment Conditions

- GOTHIC 7.0 computer code is used for Appendix R and Station Blackout

Required NPSH Defintion



RG 1.82 Position on Required NPSH

- Credit may be taken for operation in cavitation provided:
  - Protypical pump tests are performed
  - Acceptable post-test examination

VY Required NPSH

- Based on pump vendor testing and expert judgment
- VY RHR and core spray pumps tested at reduced NPSH conditions - limited number of points.
- Additional data from other pump models
- Pump vendor states that pump design characteristics important to required NPSH are identical for non-VY pumps: specific speed, suction specific speed, blade inlet angle
- Pump affinity laws applied to adjust data
- Time at reduced NPSHR: pump vendor judgment

Conservatism

- VY Response to NRC Staff RAI:
  - "The more conservative initial conditions assumed in the design bases calculations are responsible for identification of the need to rely on containment accident pressure..."

Vermont Yankee TS Change No. 263, Supplement 8, July 2, 2004

LOCA Conservatism

- Reactor power 102% of licensed rated thermal power
- Decay heat at 2-sigma
- Decay heat bounds specific cycle
- Most conservative initial conditions
- All TS parameters at limiting value
- Worst single failure short-term: LPCI Loop Select failure results in pump runout flow

LOCA Conservatism

- Worst single failure long-term: RHR heat exchanger unavailable
- RHR flow through RHR HX minimized
- RHR service water flow (ultimate heat sink) through HX minimized
- Break flow heat and mass transfer with drywell atmosphere minimizes torus pressure
- NPSH calculation based on a suppression pool water volume less than predicted at time of peak temperature

LOCA Conservatism

- Value of ECCS strainer head loss used is greater than predicted
- No temperature correction made to required NPSH
- For the long-term, the distribution of debris on the one active CS strainer and one active RHR strainer will be the amount initially deposited in the short term + redistributed from inactive strainers + amount not removed in short term

LOCA Conservatism

- Strainer temperature for head loss calculations less than predicted suppression pool temperature
- RHR pump runout flow used for long-term LOCA
- Maximum service water temperature
- Continuous spray operation (torus and drywell)
- Peak initial suppression pool temperature (90 F)
- Operation of containment spray is assumed for the duration of NPSH calculation
- RHR pump flow assumed at runout (maximum) value for duration of LOCA - operator never throttles pump

LOCA Conservatism

- Cumulative conservatism due to the assumption that all conservatisms apply simultaneously

LOCA Conservatism

Single Failure Assumption	Peak Suppression Pool Temperature
With RHRHX Failure	195 °F
Without RHRHX Failure	169 °F

LOCA Conservatism

Input Parameter	Conservative Assumption	Anticipated Value	SP Estimated Temp Diff (F)
Decay Heat	Cycle Independent	Cycle Dependent	-2.0
Long-Term Vessel Recovery with Minimum SP Cooling	2 LPCI and 2 CS	1 CS	-8.0
RHR Flow (as it affects RHRHX performance) (gpm)	6,400	7,000	-0.6
RHRSW Flow (as it affects RHRHX Performance) (gpm)	2,700	4,000	-4.8

LOCA Conservatism

- Pre-EPU Peak SP Temperature = 182.6 °F
- Peak EPU SP Temperature = 194.7 °F
- Peak SP Temp - Sum of conservatisms in table
  194.7 °F - 15.4 °F = 179.3 °F
- Peak SP Temperature - Root mean square of conservatisms in table
  194.7 °F - 9.6 °F = 185.1 °F

Conservatism

- An analysis with realistic (nominal) assumptions shows that credit for containment accident pressure is not needed.

Containment Integrity

- VY design basis analyses assume containment integrity. Based on:
  - VY compliance with 10 CFR 50 Appendix J Leak testing
  - VY compliance with 10 CFR 50.55a inspections
- Walkdowns prior to containment closure
- VY containment is inerted

Peak Containment Pressure (psig)

Pre-CPPU	CPPU
41.6	41.8

Impact on Operator

- Credit for containment accident pressure does not change VY emergency operating procedures (EOPs). Containment pressure is currently a consideration for NPSH.
- No impact on operator

Conclusions

- Credit for containment accident pressure is determined conservatively.
- A more realistic but still conservative calculation would show that credit is not needed.
- Based on stringent testing requirements, inerting and VY EPU safety analyses, containment integrity is a reasonable assumption
- Credit for containment accident pressure has no impact on the operator
- Staff finds the VY credit for containment accident pressure acceptable

Containment Accident Pressure Credit NRC Staff Risk Evaluation

Martin A. Stutzke
Senior Reliability & Risk Analyst
Probabilistic Safety Assessment Branch
Division of Systems Safety and Analysis
Office of Nuclear Reactor Regulation

Presentation Outline

- Overview of risk evaluations to support non-risk-informed license amendment requests (LARs)
- NRC staff scoping risk evaluation of proposed containment overpressure (COP) credit
- Risk insights concerning defense-in-depth
- Risk insights concerning performance monitoring
- Conclusions

Non-Risk-Informed Submittals

- General references
  - COMSAJ-97-08, "Discussion on Safety and Compliance"
  - RIS 2001-02, "Guidance on Risk-Informed Decisionmaking in License Amendment Reviews"
  - Standard Review Plan (SRP), Chapter 19, Appendix D, "Use of Risk Information in Review of Non-Risk-Informed License Amendment Requests"
- The decision to submit a risk-informed LAR is voluntary on the part of the licensee

Process to Obtain Risk Information

- 10 CFR 2.102 gives NRC authority to require the submittal of information in connection with an LAR
- SRP 19, App. D provides the process to obtain risk information about a non-risk-informed LAR:
  - Staff requests risk information
  - If licensee declines, staff must show that the LAR raises questions about adequate protection of the public health and safety in order to require the licensee to provide risk information

Process to Obtain Risk Information (Con't.)

- Licensee needs to address the five key principles of risk-informed decisionmaking given in RG 1.174
- Licensee may decline to provide risk information, but could have its LAR denied
- Specific to extended power uprates (EPUs):
  - EPUs not submitted as risk-informed LARs
  - However, the staff expects licensees to submit a risk evaluation because a proposed EPU could create special circumstances that rebut the presumption of adequate protection from compliance with existing regulations and requirements
  - "Review Standard for Extended Power Uprates," RS-001, Rev. 0, Matrix 13

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Five Key Principles in RG 1.174 and SRP 19

- The five key principles:
  - Proposed change meets the current regulations
  - Proposed change is consistent with the defense-in-depth philosophy
  - Proposed change maintains sufficient safety margins
  - Increases in risk should be small and consistent with the intent of the Commission's Safety Goal Policy Statement (51 FR 30028)
  - Impact of proposed change should be monitored using performance measurement strategies
- Acceptability of proposed change is determined by an integrated decisionmaking process

6-6

Risk Evaluation Chronology

9/10/03	Entergy submits EPU application
12/18/03	NRC staff sends Request for Additional Information (RAI); Question SPSB-7 asked about overpressure credit in the context of PRA operator actions
1/31/04	Entergy responded to the RAI (Supplement 5)
May 2004	Staff makes scoping risk evalution of overpressure credit
5/28/04	NRC staff sends RAI; Question SPSB-C-1 asked about the overall impact of the overpressure credit on risk
7/2/04	Entergy responded to the RAI (Supplement 8)
12/21/04	NRC staff sends RAI; Question SPSB-C-45 asked about thermal-hydraulic calculations that support PRA success criteria
2/24/05	Entergy responded to the RAI (Supplement 23)
7/19/05	Staff presentation to ACRS Subcommittee on Thermal Hydraulics concerning revision to RG 1.82; discusses initial staff risk evaluation. Subcommittee suggests that the risk evaluation be expanded to include more initiating events

Risk Evaluation Chronology (Con't.)

July - August 2005	Staff expands its risk evaluation by modifying SPAR models
9/8/05	Staff presentation to full ACRS Committee concerning revision to RG 1.82; discusses revised staff risk evaluation
9/10/05	ACRS letter on proposed revision to RG 1.82 recommends that it not be published for public comment without revisions
10/5/05	Staff requests Entergy to provide a risk evaluation of the overpressure credit that addresses the five key principles of risk-informed decisionmaking in RG 1.174
10/7/05	Staff presentation to full ACRS concerning proposed revision of RG 1.82; states intent to consider overpressure credit using risk-inform decisionmaking and make RG 1.82 a risk-informed regulatory guide
10/21/05	Staff completes draft Safety Evaluation; scope of risk evaluation based on NRR RS-001 and SRP 19, App. D
10/21/05	Entergy provides partial risk evaluation (Supplement 38)
10/26/05	Entergy completes risk evaluation (Supplement 39)
TBD	Staff to develop revised draft SE that includes review of Supplements 38 and 39

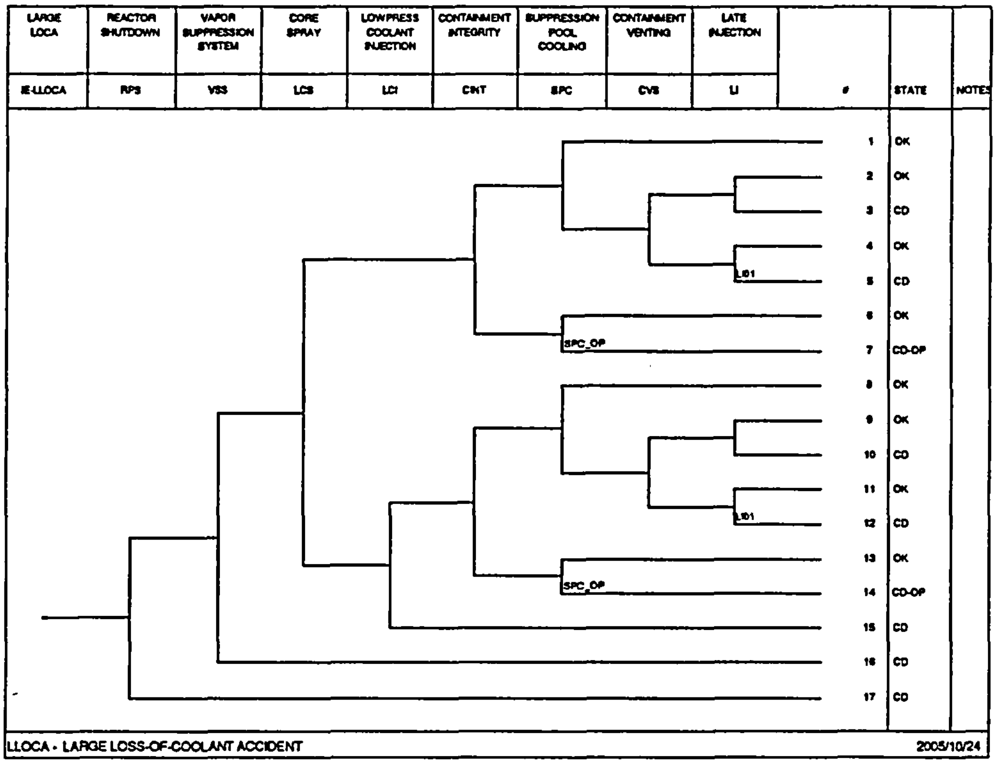
Staff Scoping Risk Evaluation

- Realistically conservative licensee thermal-hydraulic calculation indicates that containment overpressure credit is not required
- Staff risk evaluation assumes that core damage will occur only if all of the following occur:
  - Reactor coolant is discharged to the suppression pool
  - Low pressure core injection (LPCI) or core spray (CS) is required to provide reactor inventory control or decay heat removal
  - Containment integrity is lost (loss of overpressure, which leads to inadequate NPSH)
  - Operator does not initiate suppression pool cooling within four hours

Scoping Risk Model

- Modification of the Standardized Plant Analysis of Risk (SPAR) models developed by the Office of Research (RES). SPAR models are the basis of:
  - Significance Determination Process (SDP)
  - Accident Sequence Precursor (ASP) program
- Considered:
  - 11 transient initators
  - 5 LOCA initiators (including ISLOCAs)
  - Special sequence types
    - Station blackout (SBO)
    - Stuck-open relief valve (SORV)
    - Anticipated transients without scram (ATWS)

Scoping Risk Model (Con't.)



Scoping Risk Model (Con't.)

- Data to quantify loss of containment integrity (including pre-existing undetected leaks and containment isolation failures) obtained from:
  - Licensee's recent submittal for a one-time ILRT extension to 15 years
  - Office of Research (RES)
- Human failure event (failure to initiate suppression pool cooling within four hours):
  - Cognitive Errors: EPRI Cause-Based Decision Tree Method (CBDTM)
  - Action Errors: NUREG/CR-1278, A Technique for Human Error Rate Prediction (THERP)

Scoping Risk Model (Con't.)

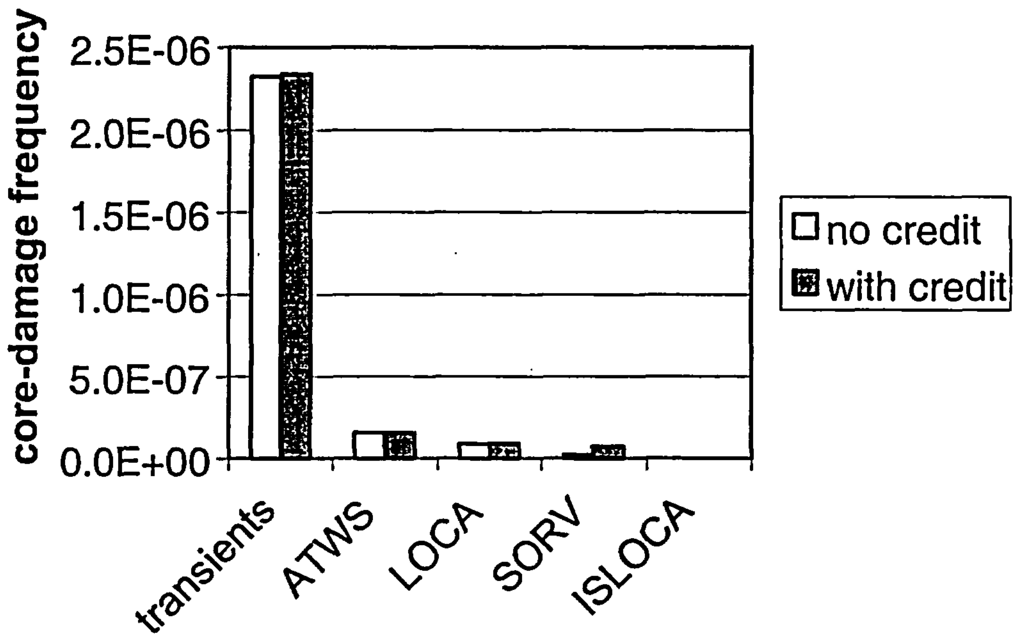
- Quantification method:
  - Truncation limit: 10^{-12} per year
  - 5000 Monte Carlo samples for parametric uncertainty analysis
  - Minimal cut sets regenerated for each sensitivity analysis case
- Uncertainty analysis:
  - Parametric uncertainties
  - Modeling uncertainties
    - Containment leak size
    - Main steam isolation valve (MSIV) success criterion
    - Human reliability analysis methods

Results of the Analysis

	mean	5th percentile	95th percentile
CDF for no overpressure credit	2.6E-06	2.5E-07	8.9E-06
CDF with COP credit	2.6E-06	2.5E-07	8.9E-06
change in CDF due to COP credit	6.2E-08 2.4%	2.6E-10	2.5E-07

- Very small change in core-damage frequency (CDF) using the risk acceptance guidelines in RG 1.174

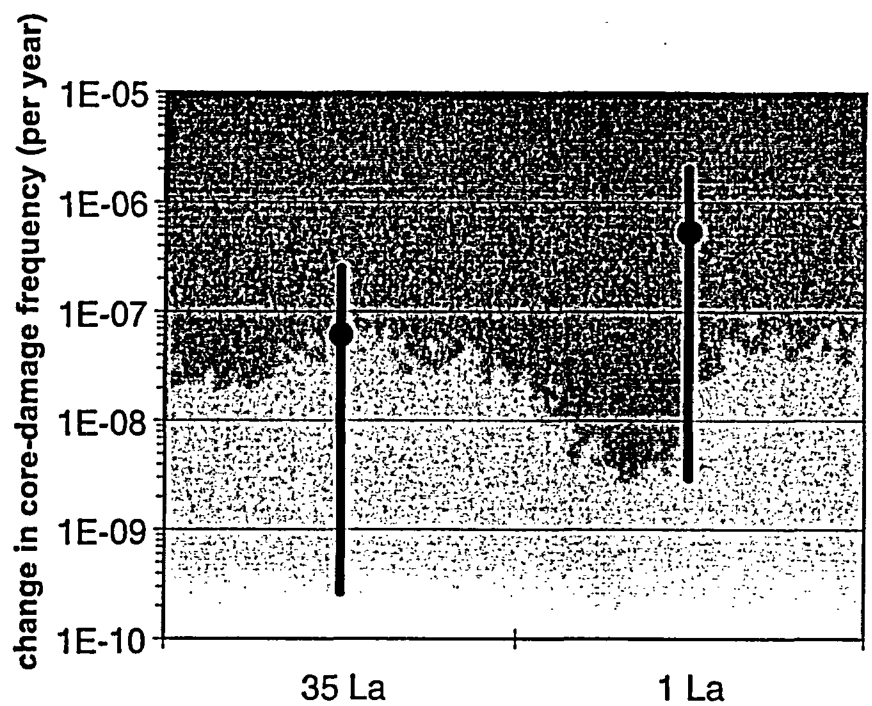
Contributions to Core-Damage Frequency



Importance Measures

Event	Fussell-Vesely Importance	Risk Achievement Worth
Pre-existing, undetected containment leakage	2.50E-02	2.8
Operator error	8.90E-03	11.3
Containment isolation failure	7.40E-04	2.7
MSIV failures	1.30E-06	1.02

Sensitivity to Containment Leak Size



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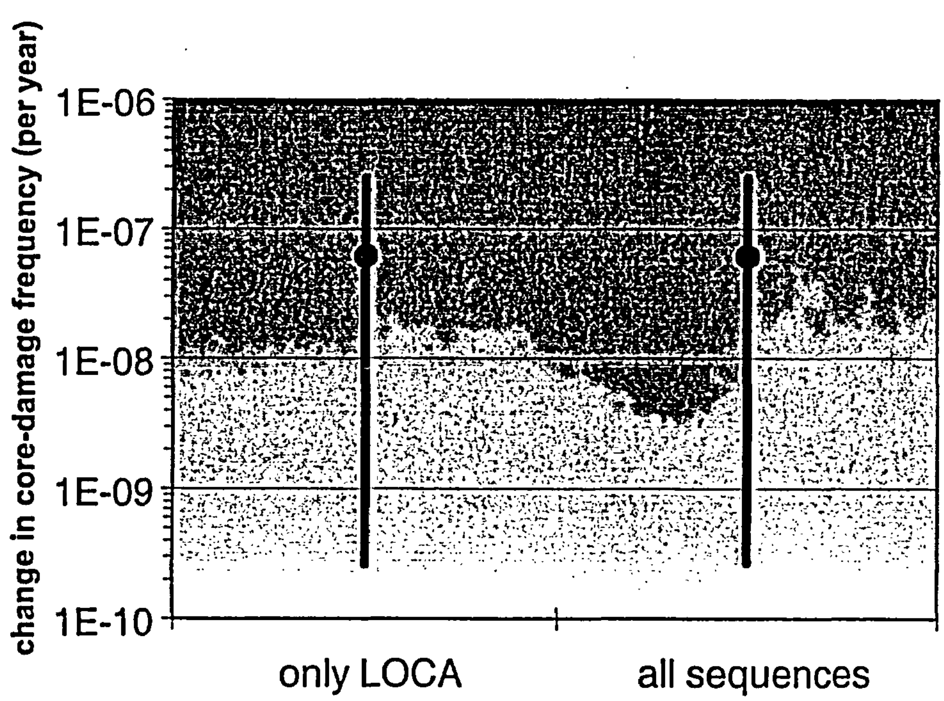
Sensitivity to MSIV Success Criterion



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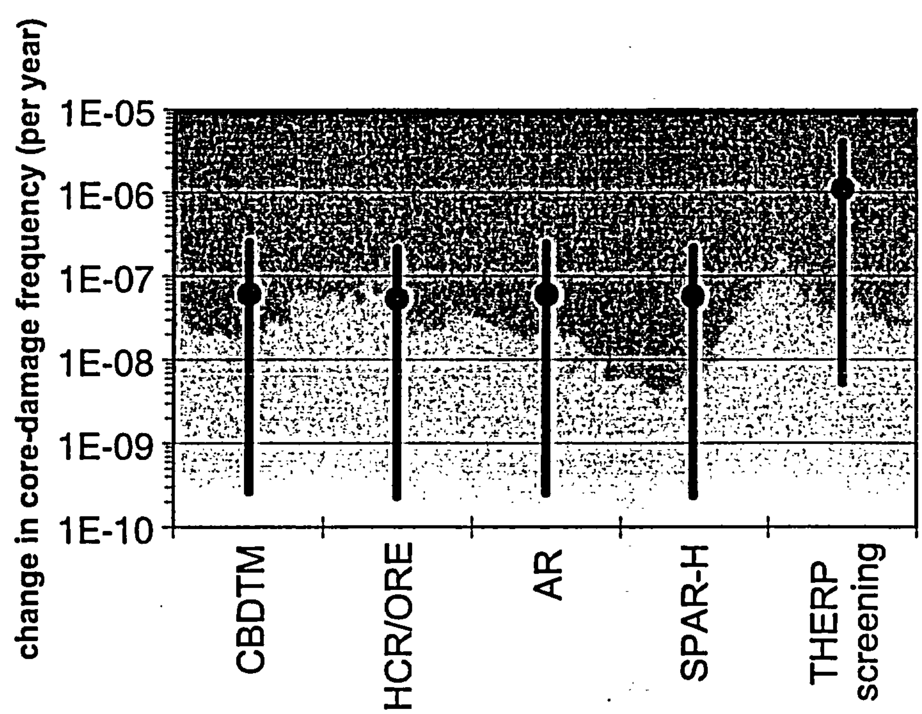
Sensitivity to Human Reliability Analysis

- Alternative methodologies:
  - HCR/ORE: Human Cognitive Reliability/Operator Reactor Experiments, EPRI NP-7183-SL (1990)
  - AR: Annunciator Response, NUREG/CR-4772 (1987)
  - SPAR-H: SPAR-H Human Reliability Analysis Method, NUREG/CR-6883 (2005)
  - THERP: Technique for Human Error Rate Prediction, NUREG/CR-1278 (1983); used for initial screening analysis

Sensitivity to HRA Method



Risk Insight: Impact on Defense-in-Depth

- PRA can provide insights about how the proposed COP credit affects the balance between accident prevention and mitigation
- Consideration of this balance is important in weighing the necessity and sufficiency of defense-in-depth measures
- Staff considered how the proposed COP credit would affect the conditional containment failure probability (CCFP) in order to evaluate the balance between accident prevention and mitigation

Approximate Impact on CCFP

$$CCFP \equiv \frac{\text{accident release frequency}}{\text{core damage frequency}}$$

R_{CCFP} = fractional change in CCFP

R_{CDF} = fractional change in CDF

Since core-damage accidents caused by loss of containment integrity will cause some form of release, it can be shown that:

$$R_{CCFP} = \frac{1 - CCFP}{CCFP} \times \frac{R_{CDF}}{1 + R_{CDF}}$$

Approximate Impact on CCFP (Con't.)

NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," Table 12.7 indicates that the CCFP for a BWR plant with a Mark I containment is generically about 0.6:

$$R_{CCFP} = \frac{1-0.6}{0.6} \times \frac{0.024}{1+0.024} = 0.016 = 1.6\%$$

This result suggests that the proposed COP credit does not significantly change the existing balance between accident prevention and mitigation.

SRP 19 Defense-in-Depth Objectives

- The LAR does not result in a significant increase in the existing challenges to the integrity of barriers.
- The LAR does not significantly change the failure probability of any individual barrier.
- The LAR does not introduce new or additional failure dependencies among barriers that significantly increase the likelihood of failure compared to the existing conditions.
- The overall redundancy and diversity among barriers is sufficient to ensure compatibility with the risk acceptance guidelines.

SRP 19 Defense-in-Depth Evaluation

- The proposed COP credit has no effect on LOCA or transient-induced SORV frequencies because it does not affect normal plant operating conditions.
- The proposed COP credit has no effect on the probability of containment failure because it does not affect normal plant operating conditions.
- Under the assumptions of the design-basis accident (DBA) analysis, the proposed COP credit introduces a dependency between the fuel and containment barriers; however, this does not appear to be probabilistically significant.

SRP 19 Defense-in-Depth Evaluation (Con't.)

- Realistically conservative analyses indicate that no COP credit is needed. Even if the COP credit is presumed to change PRA success criteria, then:
  - There must be at least three failures to cause a core-damage accident:
    - LOCA (or SORV, which requires multiple failures)
    - Loss of containment integrity
    - Loss of suppresion pool cooling
  - The mean change in CDF is very small and meets the RG 1.174 risk acceptance guidelines
  - Results are robust in terms of uncertainties and sensitivities to key modeling parameters and assumptions

SRP 19 Defense-in-Depth Evaluation (Con't.)

- The scoping risk evaluation, based on the assumption that the proposed COP credit changes the PRA success criteria, indicates that the proposed COP credit does not significantly change the CCFP. Hence, it does not significantly change the existing balance between accident prevention and mitigation.
- Therefore, the proposed COP credit meets the four defense-in-depth objectives in SRP 19.

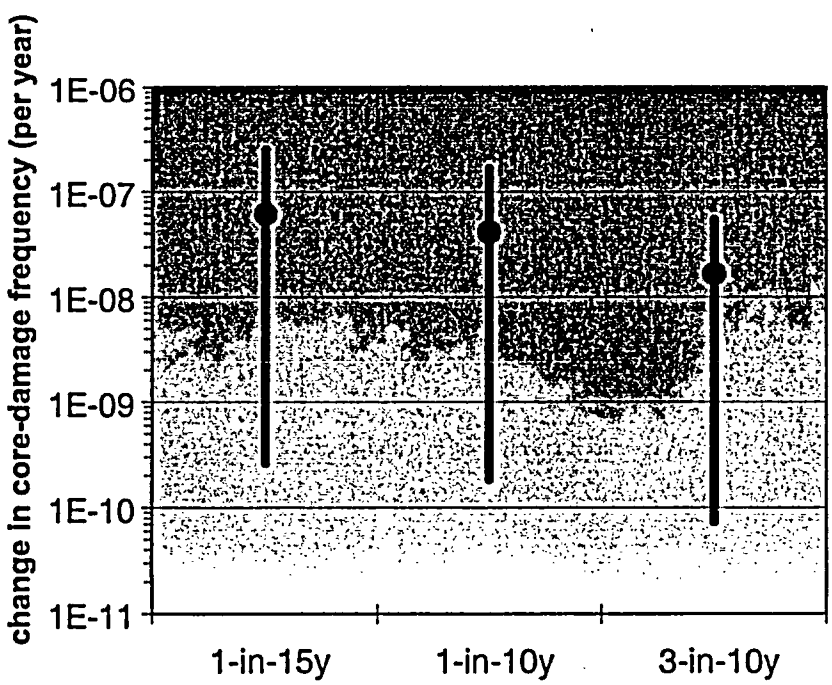
ACRS Comments on Defense-in-Depth

- ACRS letter of May 19, 1999
  - Expressed concerns about "arbitrary appeals to defense in depth" to avoid making changes to regulations and regulatory practices that seem appropriate in light of PRA results
  - Expressed the notion that there should be an inverse correlation between the uncertainty in PRA results and the extent to which defense in depth is applied
- Position reiterated in joint ACNW/ACRS letter of May 25, 2000

Risk Insight: Performance Monitoring

- The probability of pre-existing, undetected containment leaks used in the scoping risk evaluation is conservative:
  - The VY containment is inerted with nitrogen
  - Probability was estimated from results of Type A integrated leak rate tests (ILRTs) for the entire U.S. commercial nuclear industry
  - More realistic approach would be to reduce this probability since inerting provides a continual means of detecting loss of containment integrity
- A sensitivity study was performed to assess the impact of the ILRT frequency on the change in CDF

Sensitivity to ILRT Frequency



Conclusions

- Draft staff safety evaluation (SE) is based on consideration of adequate protection
- Staff will revise its SE after considering latest licensee supplements
- Staff scoping risk evaluation indicates that the proposed COP credit:
  - Has very small risk, even after considering parametric and modeling uncertainties
  - Does not significantly change the existing balance between accident prevention and mitigation
  - Meets the defense-in-depth objectives in SRP 19

Engineering Inspection

Larry Doerflein
Chief, Engineering Branch 2
Division of Reactor Safety
Region I

Agenda

- Introduction - Larry Doerflein
- Inspection Background - Larry Doerflein
- Engineering Inspection - Jeff Jacobson
- Followup of Inspection Issues - Larry Doerflein
- Impact on EPU Amendment Review - Rick Ennis
- Questions and Comments

Inspection Background

- Biennial Safety System Design and Performance Capability Inspection Scheduled
- Request for Independent Safety Assessment
- Conditions Different than Maine Yankee
- New Inspection Procedure
- Team Independence
- Vermont State Nuclear Engineer Participation

Vermont Yankee Engineering Inspection

Jeff Jacobson
Team Leader
Vermont Yankee Engineering Inspection

Inspection Background

- VY inspection was responsive to the Vermont Public Service Board request to conduct an independent assessment and provide the inspection results to the ACRS for review
- VY inspection was part of a pilot program developed to improve the effectiveness of NRC engineering/design inspections
- VY inspection was the first of four pilot inspections
- The inspection involved about 900 hours of direct inspection versus 475 for a normal engineering team inspection

Inspection Staffing and Scope

- The inspection team included an NRR team leader, four NRC regional inspectors, and three highly qualified independent contractors
- All team members were independent of any recent oversight responsibilities of VY
- The inspection team focused on components and operator actions that represented high risk and had the lowest relative safety margins
- Low margin areas were identified in part by consultation with NRR technical staff

Inspection Scope (continued)

- Forty five components, operator actions, and operating experience samples were reviewed in detail
- The components reviewed were part of the following plant systems
  - On-site and off-site electrical systems
  - Reactor core isolation cooling system
  - Residual heat removal system
  - Safety relief valves
  - Reactor feedwater and condensate systems
  - Other risk significant systems

Pilot Inspection Areas of Review

- Visual signs of degradation, installation errors, interference issues, environmental concerns
- Design and licensing basis documentation
- Review of design assumptions, system interfaces, failure modes
- Component history including maintenance, corrective action, and testing records
- Operating procedures
- Focus on functionality of equipment

Additional Reviews Conducted Specifically for VY Inspection

- Comparison against current and uprated power levels
- Assessment of design control processes applied to power uprate

Inspection Results

- Eight findings of very low risk significance (Green)
- Findings did not result in system inoperability either as compared to current or uprated power levels
- Findings were not indicative of any programmatic breakdown
- The inspection approach used during the four pilot inspections was determined to be more effective than the system based vertical slice approach that is part of the current baseline inspection program
- Plans are to adopt this low margin inspection approach into the baseline engineering inspection program beginning 1/1/2006

Inspection Findings

- Capability of Vernon Hydro-electric station to supply power to VY in event of a regional blackout*
- Adequacy of procedure used to monitor operability of offsite power
- Lack of degraded voltage analysis
- Reactor Core Isolation Cooling pressure control valve - reliance on instrument air
- Reactor Core Isolation Cooling pressure control valve - automatic operating mode inoperable

* EPU related

Inspection Findings (continued)

- Non-conservative input for condensate storage tank temperature used in transient analysis*
- Safe shutdown analysis used incorrect time for initiating reactor core isolation system from alternate control panel*
- Insufficient acceptance criteria and unverified diagnostic equipment used in motor operated valve testing*
- In addition to 8 findings, one unresolved item (URI) - ungrounded 480 VAC electrical system

* EPU related

Required Corrective Actions

- The licensee is required to enter all the identified inspection findings into its corrective action program
- Corrective actions for all eight findings will be reviewed as part of the NRC's baseline inspection program -detail to be provided by Larry Doerflien
- In addition, corrective actions to the four findings that relate to areas covered by the NRC's power uprate were reviewed by the NRC's technical staff as part of the licensee's overall power uprate submittal - detail to be provided by Rick Ennis

Followup of Inspection Issues

Larry Doerflein
Chief, Engineering Branch 2
Division of Reactor Safety
Region I

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Status of Inspection Issues

- All Eight Inspections Findings Received Followup
- Inspection completed
  - IR 2005-002
    - RCIC startup time line
    - Procedure for assessing operability of off-site power
  - IR 2005-004
    - Degraded Relay Setpoint Calculations
    - CST Temperature
  - IR 2005-006
    - Availability of Power from Vernon Hydro Station
    - MOV Testing

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Status of Inspection Issues

- More Inspection Needed
  - Design of RCIC pressure control valve
  - Non-conforming operation of RCIC pressure control valve
- Other
  - URI on Ungrounded 480V System - Task Interface Agreement (TIA)

Engineering Inspection Impact on EPU Review

Rick Ennis
Senior Project Manager
Divsion of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Findings Related to EPU Review

- The findings that impacted the EPU review were:
  - Station Blackout
  - Appendix R Timeline for Reactor Core Isolation Cooling System (RCIC) Initiation
  - Periodic Testing of Motor-Operated Valves (MOVs)
  - Condensate Storage Tank (CST) Temperature

Station Blackout (SBO)

- Finding impacts Safety Evaluation Section 2.3.5, "Station Blackout"
- Coping analysis performed to address finding (Supplement 25 dated 3/24/05)
- Review of coping analysis determined for 2-hour coping period:
  - Adequate condensate inventory;
  - Adequate battery capacity;
  - Equipment operability with loss of ventilation;
  - Containment isolation maintained; and
  - NPSH met without crediting containment accident pressure.
- Staff concluded VY will meet SBO requirements under EPU conditions

Appendix R Timeline for RCIC Initiation

- Finding impacts Safety Evaluation Section 2.11, "Human Performance"
- Time to core uncovery:
  - 25.3 minutes (current power level)
  - 21.3 minutes (EPU level)
- Time to place RCIC in service for Appendix R:
  - 15 minutes (1999 analysis)
  - 21 minutes (inspection team finding)
- Procedure revised to address finding.
- Results of timed operator crew walkthroughs of revised procedure submitted in Supplement 22 dated 12/8/04:
  - Times ranged from about 12 to 15 minutes
  - Average time about 13.5 minutes
- Staff concluded that sufficient margin exists to place RCIC in service during an Appendix R event under EPU conditions

Periodic Testing of MOVs

- Finding impacts Safety Evaluation Section 2.2.4, "Safety-Related Valves and Pumps"
- Licensee did not manage commitments and conditions in SE for GL 96-05 MOV Periodic Verification Program
- Supplement 16 dated 9/30/04 committed to revise MOV Periodic Verification Program
- Supplement 32 dated 9/10/05 stated commitment is complete
- Staff concluded safety-related valves will continue to meet applicable requirements following EPU implementation

CST Temperature

- Finding impacts Safety Evaluation Section 2.6.5, "Containment Heat Removal"
- Supplement 18, dated 10/5/05 revised ATWS analyses for EPU
- Increase in CST temperature increased suppression pool temperature from 190F to 190.5F
- Peak suppression pool temperature for limiting event (LOCA) is 194.7F
- Staff concluded effect of CST temperature change is acceptable since limiting temperature will not be exceeded

Conclusions

- Licensee submitted supplements to EPU application to address all 4 findings
- NRC staff has reviewed information and concludes the issues have been adequately addressed

Engineering Inspection Summary

- Engineering inspection was responsive to the Vermont Public Service Board request (hours spent, scope, independence)
- Inspection approach considerd an improvement over vertical slice approach
- All of the inspection findings were of low safety significance
- All inspection findings have received followup inspection for corrective actions
- Findings impacting the EPU have been adequately resolved as addressed in the NRC staff Safety Evaluation

ACRS Subcommittee on Thermal-Hydraulics

November 16, 2005

Comments on the Vermont Yankee Proposal for the Extended Power Uprate

Dr. Joe Hopenfeld

On Behalf of

New England Coalition

PRINCIPAL AREAS OF CONCERN

- Steam Dryer Failure
- Lack of Adequate NPSH Margins
- Flow Accelerated Corrosion
- Iodine Release

Steam Dryer Vibrations

Theoretical Predictions

- Predictions of fatigue failure of the dryer are based on two computer models: the **Computational Fluid Dynamics model (CFD),** and the **Acoustic Circuit Model, (ACM)**
- Neither the **CFD** nor the **ACM** were benchmarked against full scale tests.
- The flow field in the dryer is complicated by its complex geometry. And the thermal expansion of the dryer during transients may affect the natural frequency of the dryer. These are only two examples of why a validation of the models under steady state and transient conditions is required.
- The ascension to power tests do not validate the **CFD** nor the **ACM.** The ascension to power test do not represent the loads that the dryer would experience during transients such as Main Steam Line Break (MSLB), for example.
- In conclusion, the uncertainties in the CFD and the ACM reduce the reliability of converting plant data into dryer loads.

Steam Dryer Vibrations
Dryer Failure

- Recently discovered cracks in the VY dryer indicate that stresses in the dryer may be exceeding design levels.
- The growth of such cracks from flow induced vibrations during steady state operations or from dynamic loads during coolant depressurization will cause an accelerated crack growth and possible steam dryer fragmentation.
- Based on the experience at Quad Cities, dryer fragments may migrate to the steam line and fragments may be shed down on to the fuel.

STEAM DRYER VIBRATIONS

Safety Consequences

- The Quad Cities dryer failures should be viewed as precursors of similar incidents at VY under the EPU.
- The Quad Cities incidents should also be viewed as a "near misses" of fuel channel blockage or MSIV blockage <u>during LOCA events</u>.
- VY should be required to analyze the above worst case scenarios in a manner that provide adequate assurance that the EPU will not increase the core damage frequency beyond the present level.
- Assumptions per 10CFR50.92 criteria should be presented and defended.

Steam Dryer Vibrations
Lessons Learned

- After the Steam Dryer failures at Quad

Cities, the Industry attributed the event to:

" the lack of industry knowledge of flow-induced vibrations dryer failures"

- This assessment, it appears, still applies to the VY methodology.

Steam Dryer Vibrations Conclusions

It has yet to be demonstrated, per 10CFR50.92, that the proposed EPU will not –

1. Involve a significant increase in the probability or consequences of an accident previously evaluated.
2. Create the possibility of a new and different kind of accident from any accident previously evaluated.
3. Involve a significant reduction in a margin of safety.

Lack of Adequate NPSH Margins

- Pressure drop across inlet pump screen is a major uncertainty
- Increase in coolant sludge concentration and other debris increases the potential for screen blockage.
- In one part of their analysis VY indicated that the EPU will increase sludge content. In another part of the analysis VY indicated that the EPU has no effect on the debris source term.
- The VY analysis with respect to NPSH margins is not conservative.

Flow Accelerated Corrosion, FAC

- VY analysis of wall thinning is based on a computer model, CHEKWORKS
- CHEKWORKS can only be used to rank components with respect to their susceptibility to FAC but not as a predictive tool of actual material loss.
- Many failures have occurred from FAC since CHEKWORKS was developed in 1986 (La- Salle, Sequoyah, ANO-2, San-Onofre, Mihama)
- VY's account of the effects of EPU on the wall thinning of critical components is not conservative. Material loss is assumed by VY to be proportional to the velocity. It is more likely to be proportional to velocity squared.

Iodine Release

- Because of higher feed water flow rates at EPU conditions the initial iodine concentration of the coolant will decrease.
- Empirical data indicates that the iodine spike increases with the decrease in iodine concentration.
- VY did not evaluate the pre accident iodine spike in terms of the actual iodine concentration in the coolant at EPU conditions.
- The empirical concentration of the 4uCi/g used by VY may not be applicable to the EPU.
- VY did not discuss why the effect of the concurrent iodine spike during the MSLB accident was not included in the calculations.
- The ACRS, in NUREG 1750, and at the 02/03/04-04/04/04 meetings, concluded that the NRC is not addressing the iodine spike adequately. They could not conclude that the allowable dose limits (10CFR 50, 10CFR100 10CFR50.67 and GDC 19) would be met during the MSLB accident.
- The NRC has recently initiated work on a new generic issue (GSI 197) to resolve the iodine spiking issue. NRC must bound the uncertainties in GSI 197 before one can be assured that VY will meet federal laws with the proposed EPU.