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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

DATE: March 11, 1994

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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407th ACRS MEETING

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Nuclear Regulatory Commission
Conference Room P-110
7920 Norfolk Avenue
Bethesda, Maryland

Friday, March 11, 1994

The Committee met, pursuant to notice at 8:30 a.m., before E. Wilkins, Committee Chair.

PARTICIPANTS:

E. Wilkins, ACRS Chairman

T. Kress, ACRS Vice Chairman

C. Michelson, ACRS Member

C. Wylie, ACRS Member

H. Lewis, ACRS Member

I. Catton, ACRS Member

J. Carroll, ACRS Member

W. Lindblad, ACRS Member

P. Davis, ACRS Member

R. Seale, ACRS Member

W. Shack, ACRS Member

S. Duraiswamy, Designated Federal Official

C. Serpan, NRC/RES

T.Y. Chang, NRC/RES

J. Murphy, NRC/RES

P. Kadambi, NRC/RES

F. Coffman, NRC/RES

J. Vora, NRC/RES

C. McCracken, NRC/NRR

A. Chaffee, NRC/NRR

E. Benner, NRC/NRR

M. Lesser, NRC/NRR

M. Virgilio, NRC/NRR

PARTICIPANTS [continued]:

G. Bagchi, NRC/NRR
R. Sharpe, Duke Power
P.M. Abraham, Duke Power
R. Gardner, NRC Region III
W. Kropp, NRC Region III
S. Orth, NRC Region III
D. Gipson, Fermi Nuclear Plant
P. Fessler, Fermi Nuclear Plant
L. DeLong, Fermi Nuclear Plant
S. Bartman, Fermi Nuclear Plant
D. Powel, Fermi Nuclear Plant
D. Modeen, NUMARC
T. O'Hara, Yankee Atomic

P R O C E E D I N G S

[8:30 a.m.]

MR. WILKINS: The meeting will now come to order. This is the second day of the 407th meeting of the Advisory Committee on Reactor Safeguards.

During today's meeting, the Committee will discuss and/or hear reports on the following; one, multiple system responses program; two, turbine generator failure event at the Fermi Nuclear Plant Unit 2; three, loss of off-site power and steam generator dry-out event at the McGuire Nuclear Plant; four, reconciliation of ACRS comments and recommendations; five, future ACRS activities; six, report of the Planning and Procedures Subcommittee; seven, revisions to the LLNL probabilistic seismic hazard methodology for the eastern United States; eight, preparation of ACRS reports.

Portions of today's meeting will be closed to discuss information the release of which would represent a clearly unwarranted invasion of personal privacy and to discuss organizational and personnel matters that relate solely to the internal personnel rules and practices of this Advisory Committee.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Mr. Sam Duraiswamy is the Designated Federal Official for the initial portion of the meeting.

We have received no written statements or requests for time to make oral statements from members of the public regarding today's sessions. A transcript of portions of the meeting is being kept and it is requested that each speaker use one of the microphones, identify himself or herself, and speak with sufficient clarity and volume so that he or she can be readily heard.

I don't have any specific or general comments to make before we get started. Do any of the members have anything they'd like to get off their chest?

[No response.]

MR. WILKINS: All right. We will proceed, then, with the first item on this morning's agenda, which is the report on the multiple systems responses program. I will turn the meeting over to the Subcommittee Chairman, Mr. Carl Michelson.

MR. MICHELSON: I'm not sure I'm the Subcommittee Chairman, but I was the one that had the interest in it.

MR. WILKINS: Fine.

MR. MICHELSON: I believe tne staff is going to give us a briefing this morning on this program. I think it was about a year or so ago we last heard from you and this is just a briefing to bring us up to date and see what the staff's current thinking is.

Thank you.

[Slide.]

MR. SERPAN: Good morning. My name is Charles Serpan. I'm the Chief of the Engineering Issues Branch in the Office of Research. I will give a short introduction to the presentation this morning and then T.Y. Chang will give you the major presentation.

[Slide.]

MR. SERPAN: Our intent today is not to give you a detailed description of our findings on all 21 issues, but rather to give you a brief overview of the conclusions, a road map, if you will, of what we have found in reviewing these issues. What we've done is reviewed all of the existing and ongoing NRC programs to make sure that these issues are either covered someplace or are going to be covered, have been covered, or are somehow being taken are of. As it turns out, we have found that to be the case, I think, in all these cases.

The details are in the report that was circulated to you and as a result of this meeting and perhaps a few more pieces of information we may get, we'll do a final update on that. So we will not try to go into great detail on that, but we will give you the issue and we will give you the conclusions of what we have found from that.

If you've got questions, of course, we'll try to answer them and we do have some help here from other staff people that are involved.

We will deal mostly in just this one hour on the first 12 issues, because the remaining, I guess, 11 issues or whatever it is we find fall into the IPEEE framework and we believe that they're going to be handled much more effectively in that. So we're not going to go into any detail on those at all. I think we're probably going to require the entire hour for these 12 issues.

MR. MICHELSON: Since you're not going to go into detail on them, I just wanted to ask you, first of all, are the people doing the IPEs sufficiently aware of the nature and extent of the issues so that their IPE really will cover the issue?

MR. SERPAN: Indeed, they are.

MR. MICHELSON: And how are they informed of that?

MR. SERPAN: I can't tell you that. I would ask Joe Murphy, who just walked in, if he could answer that question. How are the IPE folks informed of these MSRP issues to be sure that they're getting handled?

MR. MURPHY: By the publishing of the report and putting out the information, the people doing the IPEs will know about it. Now, be aware that the nature of our IPE review does not go into great details in all areas.

MR. MICHELSON: That's right.

MR. MURPHY: We look for the assumptions of the boundary conditions of the analysis. So I'm not saying it will necessarily be reviewed in great depth. The important thing is that the people doing the IPEs know about them.

MR. MICHELSON: But you think by issuing that report and putting it on their bookshelf that they will be sure to be using it. It may not even be on their bookshelf. You issue the report, all right, but whether they got one or not I don't even know.

MR. MURPHY: I would hope we get it in the right hands and I would like to think that a competent analyst would react to the information being given.

MR. MICHELSON: Has the staff ever informed in some kind of a written document that the licensees that are doing the IPEs should be aware of this report and be sure to incorporate it? Just words like that.

MR. MURPHY: That has not happened yet. We have put out addendums to the generic letters and information --

MR. MICHELSON: I've seen those and I've never found any real addressing of these lesser issues. I found that you're addressing a couple of the major ones in some of the IPE correspondence, but I don't find any reference to the other half that you think are going to be picked up by IPE by osmosis or something.

MR. MURPHY: I don't mean it by osmosis. The actions to get the information out haven't happened yet. They'll happen as we complete --

MR. MICHELSON: The IPEs are getting done. The actions after the fact won't be too helpful.

MR. MURPHY: I would agree with that. We only have four done at this point, though.

MR. MICHELSON: Yes, but I'm sure the other ones must be in advanced stages of being done by now, according to your required schedule. They must be well along the way.

MR. MURPHY: The IPEEEs will be coming in over the next four years. So I'd say there is still time to effect the nature of what's been done.

MR. MICHELSON: Is there any intention on the part of the staff to inform the licensees to be sure to address these last 12 issues that you say are going to be picked up by IPEs?

MR. MURPHY: We haven't reached a decision as to how to go about doing that, but I think we definitely need to inform the licensees of what we've done.

MR. MICHELSON: I would have been quite happy if I just had seen a piece of correspondence that says be sure to look at these, these are intended to be an integral part of an IPE and IPEEE, and that we would expect to see some comments in the IPEs concerning what they thought, if anything.

MR. MURPHY: We will give serious consideration to putting out a notice to that effect.

MR. SERPAN: That's all I have by way of introduction. Thank you.

MR. CARROLL: Carl, maybe Joe can get back to Doug with status on a periodic basis as to whether this letter is going to go forth.

MR. MICHELSON: If a letter is issued, we'd surely want to have it brought to our attention. Normally, we see it, but it might slip through somehow and not be recognized for what it is. So I would like to know when it is issued, if it is.

MR. CARROLL: Maybe you ought to call him once a week or so.

MR. MICHELSON: No, I don't think that is quite appropriate. The Committee certainly shouldn't forget about it.

MR. MURPHY: I assure you I've gotten the message.

[Slide.]

MR. CHANG: My name is T.Y. Chang. I'm with the Engineering Issues Branch of the Office of Research. Since Mr. Serpan has already covered the background information, I'll just go straight into the first tough issues.

In Issue 7.4.1, here the concern is that the human errors can cause common mode failures, common cause failures which may lead to unplanned events or affect redundant trends. The finding of the staff is that usually errors of omission is addressed in PRA, but not errors of commission.

However, the letter is still a priority Research item being studied. The current staff approach is trying to apply the human engineering principals to reduce human errors through research and regulatory activities. In addition, IPE covers common cause failures from errors in operation, maintenance or testing.

So the staff believes that the with the above-mentioned approach we will reduce the likelihood of human errors and that the ongoing program is adequate to address the concern.

MR. SEALE: Errors of commission suggest failure or inadequacies in training content and quality. That is you didn't do it, but more likely you did it wrong. You did it improperly.

MR. CHANG: Right.

MR. SEALE: You say the staff is looking at it. Is there specifically an examination of the relationship between the occurrence of these errors and some deficiency in training programs that's a part of that evaluation?

MR. CHANG: Yes. I'd leave that question for Mr. Frank Coffman. He's from the Human Factors Branch of Research.

MR. COFFMAN: My name is Frank Coffman and I serve as Chief of the Human Factors Branch in the Office of Research. I'm not sure I caught the thrust of the question. If the question is whether or not regulatory activities address the quality of training programs in their preparation of the operators, then, yes, that's an ongoing activity of looking at training programs. In addition, there is a training rule.

MR. CHANG: Yes.

MR. SEALE: Specifically, though, where you do have an identified error of commission, is there an attempt then to go back and look at specific root cause or whatever within the training program?

MR. COFFMAN: Yes. It is not limited to the training program. Whenever there is an event, the -- and where the agency gets involved in the investigation, it searches for the root cause or causes, including training. There is guidance there. The industry has an analogous program.

MR. SEALE: Thank you.

[Slide.]

MR. CHANG: Issue 7.4.2, the concern here --

MR. CARROLL: I might mention, Bob, that AEOD has had a program of going out and looking into events that they feel have some human factors content and have published several status reports on the results of those investigations. They're pretty interesting reading.

MR. SEALE: Thank you.

MR. CARROLL: Maybe, if you'd like a copy, somebody can get you one.

MR. SEALE: Good.

MR. CHANG: Issue 7.4.2, the concern here is that even though 10 CFR 50 requires separation of control and protection systems and also independence of the protection system, if there is undetected interdependency between the two, the failure of the control system may impact the protection system.

The conclusion is that USI A-17 studies show that a full-scope plant search of system interactions is costly in terms of time and money, and, even so, there is no assurance that all or even most adverse safety system interactions will be discovered.

Rather, we think the IPE process will provide a framework for evaluating interdependencies of the two systems and it should identify plant-specific potential sources of vulnerabilities.

MR. MICHELSON: How is that done? How is that accomplished?

MR. CHANG: Through the IPE review.

MR. MICHELSON: No. I mean what does the IPE --

what do they do to accomplish that objective? What do you think the IPE is going to do to accomplish that objective?

MR. MURPHY: Basically, it's the structured and integrated approach of doing the fault trees and event trees. It causes you to look at the various systems and how they interact with each other.

MR. MICHELSON: But let's get down to some aspects of the true issue. For instance, your PRAs don't incorporate such things as environmental changes around a piece of equipment which then causes the equipment to start producing, shall we say, unwanted actions around the plant. You could pick it up in the PRA.

MR. MURPHY: A number of them do.

MR. MICHELSON: Beg your pardon?

MR. MURPHY: A number of them do include that.

MR. MICHELSON: I'd like to look at one good example. If you've got one, I'll look at it.

MR. MURPHY: Let me find one for you.

MR. MICHELSON: Okay. Send it to Doug. I'd like to see how you -- pick a good one, now, and one that you think has really been done as well as any in the industry. That would certainly be a bound, then, on what they are doing. I haven't found any examples, but you look every day and I look occasionally. But that has been one of the issues. The difficulty the utility has is, of course, they have no data on how that black box performs when you heat it up, for instance, like if you lose the room cooling to it. They just don't know how it performs.

They do know what it's interconnected with, but they have to now look at it in terms of a number of things happening at once and not just one single event.

MR. MURPHY: I can use the example that I'm most familiar with, NUREG 1150, for instance, the room heat-up concern. We started changing the failure rates and we started changing the failure rates well below the EQ value.

MR. MICHELSON: The problem is it isn't a question of failure. It's a question of maloperation, which is one way of saying a failure, but the maloperation is creating events around the plant, because it's causing valves to open or close, it's causing pumps to start or stop, the ventilation system is shut down, whatever.

This is not hypothetical. This is real. We have a few LERs in which people have lost ventilation to rooms and, sure enough, things do happen when the equipment even gets a little warm. Like up to 100 degrees Fahrenheit, things start happening, as is the case in McGuire.

This is not hypothetical. That is system interaction and that generally doesn't show up in PRAs because the people don't have the database with which to know the response of the equipment to elevated conditions.

MR. MURPHY: I would agree with that. I don't know how you'd handle it.

MR. MICHELSON: That's what I'm trying to search out. How do we handle it? One good way of handling it, of course, is to get the equipment shut down when it starts getting warm. At least you won't get the maloperations from it.

MR. DAVIS: The normal assumption, as I think Joe said, is that you assume failure as soon as it --

MR. MICHELSON: And failure by definition means it just quits. Nothing good or nothing bad comes from it. It neither performs the function you want nor does it perform a function you don't want. That's how it's being treated and that's not the concern of system interaction, as I read it. The concern is unwanted actions, and that's what this issue is all about.

MR. DAVIS: Usually, the unwanted action is that it doesn't do what it is supposed to do.

MR. MICHELSON: In PRA space, that's right.

MR. DAVIS: For safety systems, they fail to actuate.

MR. MICHELSON: But in accident situations, that's not right. Sure enough, the --

MR. DAVIS: It may not be right in some cases.

MR. MICHELSON: In a case of a very large fire that was experienced a long time ago, that's what happened. Valves started opening that weren't anticipated. Lots of things happened. And it has happened since. It's happened in the case of McGuire. Nothing bad happened, it's just that the room got warm, that area of the control room got warm. But it proves how equipment starts maloperating when it starts getting warm.

I don't think there's any doubt that that happens. Now, the question is how you cope with it, and some thought has been given to that. One thought is if we experience elevated conditions, we should shut the equipment down so it can't maloperate. It can't operate then, either, but we've already taken care of that in our PRA. What we didn't take care of in the PRA is the fact that it may maloperate.

Now, if you can write the PRA such as to include all the regime of maloperations and you're still okay, you're fine, but you don't do that normally.

MR. MURPHY: I would agree that the maloperation is not in the PRA, but it's largely because there's no data.

MR. MICHELSON: That's right.

MR. MURPHY: But that also implies it's a low probability.

MR. MICHELSON: That's what we're doing. We're now understanding the problem. Now, the question is what are we going to do, if anything, about the problem and has any real thought been given to how to cope with such problems; until we have a fire, and then it's kind of late.

Sure, you can run around and try to shut the equipment down because it's doing things you don't want it to do, but that's not well planned. It should be thought out ahead what you do and it should be anticipated what is going to happen so that you have a plan that's reasonable, but there is no attempt even to anticipate what's going to happen. At least I haven't seen any.

If you've got somebody that's been doing this, I'd sure like to look at how they do it.

MR. MURPHY: We have not focused on the maloperation.

MR. MICHELSON: Well, that's been the whole -- we must have repeated it, at least for the last ten years, a dozen times a year. It's the unwanted actions that you've got to worry about, not the loss of the wanted action. I think that's what system interaction concerns, at least in part, are about.

MR. MURPHY: I think what we have done is probably the most we can do, which is every time something has happened, we've gone out of our way to issue notices and bulletins to inform the industry, so that we share all the information that is available.

Our problem is one of a small database. As I said, the good news we can draw from that is that these are relatively very rare.

MR. MICHELSON: It's a real design issue. In the case of a person that wants to put even one train of electronics on a room, should you require air conditioning to the room or should you accept single train air condition to the room? Real fundamental design issue. In some cases, we're accepting single train. In other cases, people are putting in dual train. My own view is, yes, you should put in dual trains because of the nature -- the sensitivity of electronics to elevated temperature.

It's rather rapid sensitivity. It doesn't take very long.

MR. CATTON: Why not just change the requirements for its operation?

MR. MICHELSON: The staff could, but I think before the staff could do it, they have to think through the problem and recognize the issue. That's what this study was hopefully all about.

MR. CATTON: Maybe somebody ought to toast some of that equipment and see what it does.

MR. MICHELSON: We have in the LERs. We know what's happened in the few good cases that we've got. It does cause maloperations and it doesn't take highly elevated temperatures to do it, either. The higher you get, of course, the more maloperations you get and, generally, the reversible, cool the equipment back down and it will start operating right. But in the meantime, it has opened valves and whatever. But that's what this issue is all about. I thought everybody agreed on that.

MR. CHANG: As Mr. Murphy mentioned, in addition, we have feedback of operating experiences to the licensees through notices, letters and bulletins. All this should be helpful to address the issue.

[Slide.]

MR. CHANG: Issue 7.4.3, the concern here is that the digital control systems may present complex or unexpected failure modes that might impact a protection system. Also, use of digital control systems that are actually for safety purposes may cause some concern.

The conclusion on this --

MR. MICHELSON: Excuse me. This issue really wasn't highlighted much in '89 as digital. It was highlighted as INC, which, in those days, was still predominantly analog. The digitals have only been a very recent situation. The same argument entirely applies to analog instrumentation and control, as well.

MR. CHANG: The information was taken from the Oak Ridge report. They surveyed the concerns and so forth.

MR. MICHELSON: I'll go back and read it, but I didn't think that they only talked about digital, because digital wasn't big in '89 compared with now.

So I'm a little surprised. I'll go back and read it. I'm surprised that that's all we thought the problem was in '89. You still have the analog problem and it's very similar to this problem.

MR. DAVIS: Isn't that captured under the first concern, which is not limited to digital?

MR. MICHELSON: I was looking at the title mostly.

MR. CHANG: The title is digital.

MR. MICHELSON: I think they just take it off the title and the rest of the slide isn't really quite as bad.

MR. CHANG: The conclusion on this issue is that NRR considers this issue in their review of digital systems in both operating plants and advanced reactors. In addition, current research and digital systems criteria development are also addressing this issue.

This issue is part of the ongoing National Academy of Sciences and the National Academy of Engineering study.

MR. CARROLL: Ongoing? It hasn't started yet.

MR. CHANG: It's going to start, yes.

MR. MICHELSON: On the analog end of the business, we've got various level instruments and so forth which, when you lose the power to them, fail in various modes. Some fail full upscale, some full down, and some stay where they are and keep operating even though the power has failed.

That was the kind of interaction we were also concerned about, what happens when you lose -- when your voltage degrades or your air pressure degrades. Some of these are air-powered type instruments. What happens when those kinds of things happen?

The instrument is fine, but the power dropped. The power dropped 30 percent on it. Well, you've got LERs in which these things have been happening and, sure enough, the instruments maloperate. Some of them, when you lose voltage to them, they just keep staying where they were before they lost the voltage and they keep sending -- there is still a valid circuit signal. The instrument people tell you all about this.

That's the question here. You might lose the auxiliary power. Now what happens in terms of system interaction? It gets rather tenuous.

MR. MURPHY: Again, I think we've learned lessons from the LERs and these are factored into our normal review process. I know questions like the bias in the control system of the B&W plants were being discussed 15 or 20 years ago.

MR. MICHELSON: Yes.

MR. MURPHY: But that's now relatively well appreciated.

MR. MICHELSON: Is it in the IPEs? I assume all these issues are more or less in the IPEs, aren't they? Some of them to a lesser extent. Those last 12 you said were --

MR. MURPHY: Yes. To the extent that they are a problem on a specific plant and we picked a plant to look and see if they are dominant contributors. The degree modeling, you may make a decision early that for a given design reason, this is not a big problem in your plant. You may not have explored it in great detail.

MR. MICHELSON: You won't get it from the PRA unless you're doing that kind of a PRA, and I haven't seen one of those kind where you look at the ancillary power, you degrade the power and then look at the fault trees to see how they behave as a result of reduced voltage.

MR. MURPHY: If there is a reason -- the type of PRAs we did in the early 1970s where we were experiencing problems with the control systems at certain plants, then we went into some detail to explore those. Once we thought those problems were fixed, we did not go into great detail in exploring the intricacies of control circuitry, for example. The bias on the B&W plant was one.

MR. MICHELSON: Rancho Seco was a good example of how these things misbehave when you change the voltage. That was long after the early 1970s, somewhat after the early 1970s. It was mid to late 1970s.

MR. CARROLL: Late 1970s, I would say.

[Slide.]

MR. CHANG: Issue 7.4.4, there are two concerns here. The first is that scram without a turbine trip may lead to overcooling of the primary system and cause recriticality. The second one is that the steam generator overfill resulting from a steam generator tube rupture may lead to a main steam line break and more steam generator tube ruptures.

Those two issues have been addressed in two generic issues. One is GI-144. That addresses the first concern. That was evaluated as a low priority back in 1992. The second issue was addressed in GI-135. It was resolved in 1991.

The conclusion from the technical finding report is that this concern has relatively low public risk. So these two concerns have been evaluated through the GI process and resolved with no additional actions needed.

[Slide.]

MR. CHANG: Issue 7.4.5, the concern here is the degradation of HVAC may impact safety-related equipment either directly or indirectly. Generic Issue 143 covers this concern. It was resolved and presented to the ACRS of August of last year.

The conclusion was that the resolution did not pass the cost-benefit test. Therefore, no further action is needed.

MR. WILKINS: Just as a matter of pure logic, is it possible that some other resolution would pass the cost-benefit test?

MR. CHANG: I think they looked at three proposed resolutions and none of them passed.

MR. WILKINS: None of them passed.

MR. MICHELSON: In order to understand this one, of course, you have to understand what happens if you do lose the chilled water system in terms of its impact upon the electronics in the plant and what the electronics does further out in the plant. None of that was ever in the PRA and, therefore, they don't know what happens if you suddenly lose the cooling to the room and what the response of the electronics ultimately would be.

So it's very difficult to determine what the risk of losing the cooling is. I found GI-143 wanting.

MR. CARROLL: But it was strictly a PRA guy --

MR. MICHELSON: Looking at a piece of equipment.

MR. CARROLL: -- looking at a piece of equipment. He just stood up there. He didn't know how refrigeration equipment worked, even, but he sure as heck knew how to draw a fault tree.

MR. MICHELSON: But they didn't have a bound beyond the equipment. The consequence is measured ultimately on whether you cool the core and so forth and it didn't have all the information. This is an environmental coupling problem, which is difficult. It's not easy to treat. We don't have much data. I think we know how to do it, if we had the data, but the modeling is not all that bad. We don't have the information on how the equipment responds to elevated temperature changes.

MR. CARROLL: What kind of a letter did we write about GI-143? I can't remember.

MR. MICHELSON: Somebody can probably get a copy and refresh our memory on it.

MR. WILKINS: The NUREG document was issued in November of 1993. So that's quite recent.

MR. MICHELSON: Yes. Our letter was published before that.

MR. WILKINS: Yes.

MR. MICHELSON: It gets back to the -- we don't even have a standard review plan for chilled water systems. The staff still things that a chilled water system is a water-cooled system and it treats it like water flowing. It doesn't even -- I'm sure it understands, I'm not saying that, but they do not have a standard review plan that tells the reviewer how to review refrigeration systems.

MR. WILKINS: Correct.

MR. MICHELSON: Which are part of this issue. But that's only part of the issue.

MR. CARROLL: I think Sam is getting a copy of our letter.

MR. MICHELSON: Why don't you proceed?

[Slide.]

MR. CHANG: Issue 7.4.6, the concern here is that the effects of degraded electrical sources on safety-related equipment were not addressed in USI A-47. GI A-35 in 1981 did address degraded voltage from off-site power sources. Ongoing NRC aging research is a program on the 1E electrical power systems, which looks into the age-related degradation mechanisms, failure modes, inspections, surveillance and monitoring methods.

So with this program going on --

MR. CARROLL: That wasn't what the issue was, though, at all.

MR. MICHELSON: It wasn't an aging issue at all. This is not an aging issue. It's an issue of degraded voltage, and you've had a very fine example at Sequoyah not too long ago. Degrading means either going up or going down, going off-normal. In Sequoyah's case, it went about -- I don't remember now -- 20 percent, 18 percent or something like that, over voltage on every emergency board in the plant at the same time because they didn't have any way to trip the generator off of the board.

That's degraded voltage. Now, is that a problem? That's what you have to look at.

MR. CHANG: We think degradation, in a lot of cases, is caused by the aging process.

MR. MICHELSON: It might be. I wouldn't argue that one way or the other.

MR. CARROLL: No.

MR. MICHELSON: It's degraded voltage, though, as a phenomenon that you're worried about.

MR. CARROLL: Off-normal voltage.

MR. MICHELSON: Whatever cause.

MR. CARROLL: Whatever cause.

MR. CHANG: But the inspection, surveillance and monitoring methods, looking into the aging program, are going to help to identify those degradations.

MR. MICHELSON: You're going to be wasting your money. Your real problem is you've got to go back and understand the responsiveness of equipment to degraded conditions, either high or low; how does the equipment respond, what trouble does it get into, is that a safety issue? Well, you've got to look and see.

MR. CARROLL: One place you have done the right thing is in 89-10. You've told people to look at how motor-operated valves behave under degraded voltage conditions.

MR. MICHELSON: Yes. 89-10 is handling the issue, I think, quite well, but that's just one small part of the whole picture and that happens to be a part that's got a lot of attention and we're understanding it now. When voltages degrade, motors don't put out the torque they put out at normal voltage and other things happen.

Of course, over-voltage also is a serious issue on certain types of electrical equipment. Luckily, at Sequoyah, they were within -- they think they were within the rating of the equipment and did not find any damage, but that's the phenomenon we worry about, over-pressure of air or under-pressure of air, over and under-voltages, changes of frequency. These are the issues you have to deal with.

Frequency change is usually not much of a problem because it's hard to get it to change much with any imaginable mechanisms. For a few cycles, it's not too hard to imagine.

MR. CARROLL: I don't think this conclusion reflects the concern of all. So I guess I would say you ought to reconsider that one.

MR. WILKINS: Is it conceivable that as part of this age-related research that you're worrying about that people will do enough studies as to what happens as a consequence of the degradation that arises from aging-related activities, that they will have information that will be useful in answering questions about degradation that arise from any other source?

MR. MICHELSON: When you look at studying aging, you don't start studying the response of this equipment to a power surge.

MR. WILKINS: To power surges, yes.

MR. MICHELSON: A spike and so forth. It could be, but I don't think it's usually the scheme.

MR. MURPHY: I think there are two general issues here and we may be mixing them up. The overall effect of degradation in off-site power systems is considered under A-35.

MR. MICHELSON: Yes, and that was different. Off-site power coming in, there's a lot of ways of controlling that, assuring that you're well filtered from those effects. When it's on-site, it's a lot tougher, as the case at Sequoyah, which you're probably well familiar with.

Now, I don't know whether anybody ever picked that up on a PRA, I have serious doubts that it ever was, nor do we fully comprehend the extent and consequence. Maybe Sequoyah was a good case where they were protected.

MR. MURPHY: The point I'm trying to make is the understanding of how the component itself reacts to the degraded voltage. If you study off-site degradation, you find that information out, and that's equally applicable to the on-site. It may not help you find the correction for the on-site, but it does help you understand the mechanism.

The aging program is looking at the effect of saying do you add anything in addition; do you have a different way of causing within plant concerns as the process ages.

I'm just trying to make sure that you understand that those things are separable and one is addressing a different problem than the other.

MR. MICHELSON: This whole business gets into your solenoid valves. Some of those are far more sensitive to voltage changes. Every once in a while I read an LER where they discovered, gee, we're supposed to be able to handle 80 percent of normal voltage on this solenoid and still get it to operate and they found, gee, it dropped down to, they thought, about 90 and the solenoid wouldn't operate anymore. Well, sure. Now you go back and replace the solenoid with one with better operation. But it's those things that are going to someday catch you.

[Slide.]

MR. CHANG: Issue 7.4.7 has to do with the concern of effects of degraded compressed air systems. That degradation may have an impact on the safety-related equipment. That concern was not addressed in the USI A-47 resolution.

The conclusion is that GI-43, air system reliability, was resolved in 1988 and Generic Letter 88-14 was issued. The issuance of this generic letter resulted in the following activities. First, major utility efforts to find and correct air system problems. Second, this also resulted in very aggressive industry activities; for instance, INPO, EPRI issued reports and maintenance guidance in this area.

An air-operated valve users group was formed, which meets semiannually, to exchange information and promote reliability of equipment operation.

MR. MICHELSON: That issue was handled reasonably well, but at the time of the issue, we discussed with you, and it's still an issue, that, of course, a cause for the degraded air may very well be traced back to a degraded voltage. If the two are combining together on a given solenoid valve, you may get a quite different response.

We agreed it wasn't easy to do the 80 percent voltage test in the plant to determine what the bleed-down effects would be. So we only looked at half of the problem in that issue, but clearly it's still a part of system interaction. Unfortunately, it's the degraded voltage that might cause a whole lot of things to happen in the plant at the same time. As a result, solenoids that might operate okay at normal voltage will see reduced voltage, but also see reduced air pressure because some valves opened and bled down the tanks and the pressure is down, and, man, now they're behaving differently.

That's system interaction. Now, it isn't easy to cope with, but that's the problem and that's what we're going to nibble at the edges of, and probably the best we'll ever do is nibble at the edges of the problem. We can't ignore the fact that the reduced voltage caused reduced air. Therefore, you've got to look at the combination of the two on a given component, unless you can show that it's not credible to have both. That's pretty hard to do on air systems. You get a couple of valves opening on reduced voltage and, sure enough, the pressure goes down, especially if the motor isn't operating too well.

The compressor motor may stall out at 80 percent, because those are non-safety compressors. They weren't rated for any of this. Nobody ever paid any attention to the non-safety air system. Everything was thought to fail safe, because they said, okay, we lose air pressure, the valve does this or that. Unfortunately, we don't lose the air pressure. We just degrade it. So the valve still wants to behave in some new manner. Fail safe, the best thing to do is dump the air pressure completely and then everything will fail safe.

That's systems interaction.

MR. CHANG: In the original AEOD study of this issue, there was a recommendation that slow bleed-down tests be done on the plants. However, in view of the activities going on now, the AEOD staff believes that the importance of that recommendation has diminished and that the best way to treat this probably is to monitor the licensee actions on this generic letter.

MR. WILKINS: Carl, I would like to make a logistic observation. There are 21 issues and he's just finished number seven.

MR. MICHELSON: I will ask no more questions and that will speed it up. Thank you.

MR. CHANG: We are going to concentrate and focus on the first 12 issues.

MR. WILKINS: Under that theory, you're not quite 60 percent through.

MR. MICHELSON: He'll get there.

MR. WILKINS: But we still use 70 percent of the time.

MR. CHANG: I will speed up.

[Slide.]

MR. CHANG: Issue 7.4.8, the concern here is about spurious actuation of components that may potentially damage safety-related equipment. There is a recent Research staff study on this issue. It looked at operational events from 1984 to 1991 in the accident sequence precursors program.

The results indicated that, firstly, the major cause of those spurious actuations is human error. Secondly, most of these spurious actuations led to reactor trips or turbine trips which are of marginal risk significance. Thirdly, the remaining events involved sequences which are within either the plant design basis or within the scope of existing generic issues.

So based on this preliminary study, that issue has been adequately addressed by existing GIs. Also, the application of human engineering principals will help to reduce the human error factor.

[Slide.]

MR. CHANG: Issue 7.4.9, this is about a concern that a harsh environment can potentially propagate from Zone 1 to Zone 2 through unrecognized paths, thereby rendering equipment in Zone 2 not qualified for this harsh environment.

Well, 10 CFR 50.49 requires that equipment which may see a harsh environment be qualified to it. Therefore, the staff believes this concern is a compliance issue and should be treated as such.

MR. WILKINS: It seems to me -- maybe this question is really addressed to my colleague rather than to you, Mr. Chang. You referred to equipment important to safety and I understand what you mean by that. That suggests at least there is some equipment that is regarded as not important to safety.

But we all know about these systems interactions and you get some equipment that you don't think is important to safety and all of a sudden it has an impact on something that has an impact on something that is important to safety. That's what I interpret as propagation of environments. You propagate back into an area that is important to safety from an area that wasn't.

To what extent do you think about such considerations or do you worry about them at all? I don't know enough about -- I'm not smart enough to give you a specific example.

MR. CHANG: I believe, again, the IPEs provide a framework to address these kinds of vulnerabilities. If it's a vulnerability to a severe accident, then IPE is the provided framework for identifying this kind of concern, I think.

From a legal point of view, I think 10 CFR 50.49 clearly requires that you comment -- well, where they are going to see a harsh environment, they should be qualified to that harsh environment. So this is a compliance issue, from our point of view.

[Slide.]

MR. CHANG: Issue 7.4.10 is similar to the last issue. This one is about propagation of heat, smoke and water. The conclusion is that there is an ongoing research program which looks at the effect of smoke on the digital I&C systems. In addition to smoke, they also look at the synergistic effects of temperature, moisture and so forth.

There is also an ongoing NRR fire protection task action plan. Research is developing -- Research is working with NRR to assure that this issue is considered in that task action plan.

MR. MICHELSON: Do you mean that it's been issued now?

MR. CHANG: Pardon?

MR. MICHELSON: By ongoing, you mean it has been issued. I've seen a proposed plan.

MR. CHANG: It's being updated continuously.

MR. MICHELSON: Has it been implemented? Has it been issued as a formal plan to be implemented?

MR. CHANG: We have staff from NRR to answer that question, the Plant Systems Branch, Steven West.

MR. WEST: I'm Steven West from NRR. The fire protection task action plan has been issued and I think it's been updated at least once since the original.

MR. MICHELSON: It's now in use.

MR. WEST: It's in effect, yes.

[Slide.]

MR. CHANG: Issue 7.4.11, this is about the synergistic effects of harsh environmental conditions.

MR. MICHELSON: Before you go to that, I just wanted to remind the Committee that I don't think we've ever commented on that plan yet. It was on the earlier agenda.

MR. CATTON: Have we seen it?

MR. MICHELSON: Yes. It's that thing that we got that's about that thick and it's just loaded. It's interesting as can be. You've got it. We were going to put it on an agenda earlier on. That's that SECY. I didn't realize it had been implemented. Apparently, the Commission told them to go ahead and do it. We have yet to comment on it. It's probably getting too late.

MR. WILKINS: How long have we had it?

MR. MICHELSON: We've had it probably for three months, four months.

MR. WILKINS: We had our opportunity and didn't do it.

MR. MICHELSON: Yes. I think so.

MR. McCRACKEN: Conrad McCracken, NRR. We are trying to arrange a meeting now with the subcommittee. That will be May 3 or 4 or something like that. You have plenty of time to comment on it. It's not a plan that's going to be implemented and done in three months. It's going to take a number of years.

MR. MICHELSON: I heard it was already implemented. It's now in action.

MR. McCRACKEN: The action is to go ahead and resolve the issues. That will take time to resolve them.

MR. MICHELSON: It still can be changed.

MR. McCRACKEN: Sure. We'll be looking forward to the Committee comments that we get in May.

MR. CARROLL: It's the plan for resolving the issue.

MR. MICHELSON: Yes, but I thought the Commission had probably issued an SRM that said go ahead and implement it.

MR. McCRACKEN: They just said go ahead and proceed to things you need to do to go to resolution, but part of that is evaluate the issues and decide what to do.

MR. MICHELSON: I'm slow. I misunderstood.

MR. WILKINS: And it is your intention, and, Ivan, you're familiar with this, to have this on the agenda of a subcommittee.

MR. CATTON: We had further instructions yesterday about this.

MR. CHANG: Issue 7.4.11, this is on the synergistic effects of harsh environmental conditions. NRR has an ongoing EQ task action plan and Research is working with NRR on this and the Research program plan will include the synergistic effects.

The conclusion is that concerns of this issue are being included in the EQ task action plan.

MR. CATTON: Synergistic effects of what?

MR. CHANG: Of a harsh environment, like high temperature, high pressure, high radiation and so forth.

MR. MICHELSON: On what equipment are you looking at it? On what equipment are you doing this study? It's a part of an EQ task actin plan.

MR. CHANG: This is, again, for the safety-related equipment.

MR. MICHELSON: For all safety-related equipment?

MR. CHANG: All safety-related equipment.

MR. MICHELSON: Are you going to look at the effects of pressure, temperature and --

MR. CHANG: The EQ plan, this is actually 10 CFR 50.49 EQ, is for electrical equipment, safety-related electrical equipment.

MR. CARROLL: This is limited to electrical equipment.

MR. CHANG: That's right.

MR. WILKINS: What are the principal stresses? I've heard you mention temperature, I've heard you mention pressure.

MR. CHANG: Humidity variation, all those things are considered all together.

MR. CARROLL: Smoke?

MR. WILKINS: Smoke?

MR. CHANG: I don't know whether smoke is considered there or not.

MR. MICHELSON: Water spray wouldn't be in that category, either. Water spray is not humidity. I can pass a humidity test and not pass a water spray test. So they usually try to keep it at about 90 percent relative humidity and most equipment will still handle that pretty well, and we can pass the test and we're in good shape. That doesn't mean you can spray the equipment at all.

[Slide.]

MR. CHANG: Issue 7.4.12, the concern here is that the mechanical equipment a lot of times is operating in a harsh environment, that's the normal operating condition, and subcomponents, such as seals, gaskets, valve packing and lubricating fluids may degrade and hinder the operation of the equipment.

We have some existing generic issues that address the operability and reliability of motor-operated valves, PORVs and other power-operated valves. In addition, in-service testing per ASME OM code on pumps and valves and also maintenance rules should help to identify and replace degraded subcomponents.

MR. MICHELSON: It has nothing to do with elevated environmental conditions, which is what you're really concerned about. Most equipment doesn't see it until the accident occurs.

MR. CHANG: Right. We think that the answer to the concern is really the next bullet. There is an EPRI-sponsored utility activity going on, the so-called reliability-centered maintenance program. There is a users group formed. It has been going on for five or six years. They meet every nine months or so to exchange information and to promote the reliable operation of that equipment. They try to replace those parts before they go bad.

MR. MICHELSON: It isn't a question of going bad. It's a question of whether they're even suitable to begin with. The lubricating grease on the valve stem, when you elevate the temperature in the containment to 350 degrees or whatever, is that great still okay? Well, I don't know, unless you've done some kind of testing.

MR. CARROLL: I'm not sure they got the concern right. They're saying may not be adequately qualified to normal harsh environments.

MR. MICHELSON: I don't know what a -- okay. That means because the top of the containment is always at 180 degrees, maybe -- yes.

MR. CARROLL: They're not talking about --

MR. MICHELSON: They aren't going even beyond -- they aren't going until the accident condition.

MR. CHANG: This is normal harsh environment conditions, like high humidity, high temperature, that sort of thing.

MR. MICHELSON: But during normal operation.

MR. CHANG: During normal operation, right. So for a long period of time, the concern is that those subcomponents may degrade and hinder the operation.

MR. MICHELSON: I didn't think that was considered a system interaction problem. That's just a plain environmental qualification for the normal operation. That's a regulatory compliance issue.

MR. WILKINS: It's a compliance issue.

MR. MICHELSON: It had nothing to do with system interaction.

MR. CHANG: The problem here is that for mechanical equipment, we don't have anything similar to 10 CFR 50.49. The guidance is very general there and there is no concerted utility activity in this area. Therefore -- also, there is no concerted staff review on this.

MR. CARROLL: But 50.49 is dealing with accident conditions.

MR. CHANG: Right, but that's only for electrical equipment.

MR. CARROLL: Yes, but this is not.

MR. MICHELSON: It apparently is not.

MR. CARROLL: Apparently is not, yes.

MR. CHANG: Right.

MR. CARROLL: How are you going to deal with environmental qualification of mechanical components for accident conditions?

MR. CHANG: The next bullet, I think, will answer your question. There is some ASME standard, qualification of mechanical equipment. There's a document that has been just approved and is going to be issued in the recent future. I was told by the end of May or early June it will be issued.

MR. CARROLL: By ASME.

MR. CHANG: By ASME, right. That should address the concern you just raised. However, that's for future plants and for replacements only.

MR. MICHELSON: How will it address it?

MR. CHANG: Pardon?

MR. MICHELSON: How will it accomplish it? What is it required to do to take care of the problem?

MR. CHANG: I think it's similar to the electrical equipment in a lot of instances, the requirements there.

MR. CARROLL: This sounds like something we ought to do in our Mechanical Component Subcommittee or something.

MR. MICHELSON: Or somewhere.

MR. CARROLL: Or somewhere. Have you got that as an action item, Doug?

MR. COE: I've got it.

MR. CHANG: I think I've finished all 12 issues I would like to discuss. It's 9:30 already.

MR. CARROLL: The remaining ones fall in the bag of things that you believe --

MR. CHANG: In the bag of IPE and IPEEE, right.

MR. CARROLL: Even though some of these were, also, to some degree.

MR. CHANG: Yes.

MR. MICHELSON: Most of them should have been covered. Any questions, gentlemen?

MR. WILKINS: I would just like to remind Mr. Serpan that the Committee has expressed on more than one occasion some concern that when issues of any kind are handed off to an IPE program, that somehow the agency should have a way of tracking whether those issues then get, in fact, handled and don't get lost or fall between cracks.

We've commented on this before in other situations. Let me just say this now so that you can be thinking about it. I don't expect any kind of response from you.

MR. CARROLL: In fact, we said it in --

MR. WILKINS: We said it in our letter.

MR. CARROLL: -- our letter on 143.

MR. WILKINS: Yes.

MR. MICHELSON: Thank you. We need to thank the staff. I think they did a fine job of summarizing the situation, yet again, and bringing us up-to-date. Now it's a Committee decision as to how we want to proceed from here.

MR. WILKINS: It's my understanding that you're not proposing that we write a letter or anything at this point.

MR. MICHELSON: No. I have no intent to write a letter on this. I think it was just an information briefing. I think they did a fine job of bringing us up to speed on it.

MR. WILKINS: I notice that this is approximately a year since the last such briefing and I would suggest it might not be inappropriate in February or March of 1995 to do it again.

Let's move on to the next item on the agenda, which will be a briefing on the turbine generator failure event at the Fermi Nuclear Plant Unit 2. Jay, you're the Subcommittee Chairman.

MR. CARROLL: Right. The background material on this is in Tab 9. What we're talking about is the nice Christmas present that Detroit Edison got on December 25 of last year when they had a major turbine failure and a number of consequences resulting from that. Al, you can proceed.

[Slide.]

MR. CHAFFEE: We were asked this morning to bring a discussion on two different events. My name is Al Chaffee. I'm the Branch Chief of the Events Assessment Branch. We have arranged for those -- Ron Gardner was the AIT Team Leader and he will talk first about the Fermi event.

The second event we were asked to talk about was the event that occurred at McGuire where they lost off-site power and had a steam generator dry-out. Eric Benner from the Events Assessment Branch will be here to t lk about that. We also have the AIT Team Leader, Mark Lesser, who will be here to answer questions.

Marty Virgilio over here, he's got his hand raised, he's the Senior Technical Manager who is here with this effort. For the discussion of the Fermi event, as I said, Ron is the AIT Team Leader. I also understand we have a number of other people here, a number of people from the AIT, including Hal Ornstein from AEOD, Len Olshan, who is on the team. As I understand it, he is a project manager from Maine Yankee.

We have John Tsao and Charles Willis. We also have the project manager, Jim Colburn. I also understand that the licensee has a number of people here. So maybe at this point, it might be appropriate for them just to introduce themselves.

MR. CARROLL: You're going to have to come up to a mike. You guys from Detroit Edison sit in the back of the church, do you? You can come up farther, if you'd like.

MR. GIPSON: Good morning. I'm Doug Gipson. I'm the Senior Vice President for Detroit Edison Nuclear Generation. Here with me today, and we can come up here and sit in the front, is Paul Fessler, our Engineering Manager; Len Goodman, our QA Director; Dick DeLong, our Radiological Superintendent; Steve Bartman, our Chemistry Superintendent; and Don Powel, our Reactor Shift Sup_rvisor, who is a Senior Licensed Operator that was on-shift the day of the Christmas event.

MR. CHAFFEE: Thank you. We also have a videotape which will be made available for you to view, I believe, at the end of the presentation and there are also some slides that we have to hopefully help explain the extent of the damage that occurred. So at this point, I'd like to turn it over to Ron.

[Slide.]

MR. GARDNER: As was stated, my name is Ron

Gardner and I was the AIT Team Leader. A couple of people that are here were left out of the introductions. Wayne Kropp was the Senior Resident at the time of the event and is now a Section Chief in Region III. Mr. Steve Orth from Region III looked at rad protection and chemistry and EP events.

What I'd like to do today is -- and I know we've got a lot of information to present in a short amount of time, but I'd like to provide a short overview of the December 25, 1993 turbine generator system failure, the cause of the event, as we understand it today, safety significance, and NRC response. Then I'd like to provide a brief discussion of the event, followed by a summary of our inspection results.

[Slide.]

MR. GARDNER: The first thing I'd like to speak to would be the problem itself. While operating at 93 percent power, a sudden catastrophic failure of the turbine occurred. It appeared that a turbine blade or blades broke loose from the No. 3 low pressure turbine, designated LP3 Rotor. A blade was ejected through the casing of LP3. A hydrogen and oil fire ensued at the generator exciter and adjacent areas.

Approximately 500,000 gallons of a water and oil mixture flooded the rad waste building basement. Severed condenser tubes allowed lake water from the circulating water system to enter the condenser hot well, which eventually resulted in high conductivity and high chlorides in the RCS.

MR. CARROLL: Was there a reason for being at 93 percent power? Was there some plant problem?

MR. GARDNER: Yes, sir. There was a reason. They had previous pressure pulsations and some problems with unitized actuators, I believe, on the high pressure turbine. That was causing them to operate at 93 percent power.

MR. CHAFFEE: This is Al Chaffee. Isn't part of the story also that they had gone for a power upgrade and that the 93 percent power is relative to the higher power levels?

MR. GARDNER: Sure. It would equate to about 98 percent.

MR. WILKINS: This is 93 percent of 105 percent.

MR. GARDNER: That's right.

MR. MICHELSON: The turbine speed was at rated speed and no variation.

MR. GARDNER: The turbine speed was -- I'll get into that in a subsequent slide.

[Slide.]

MR. GARDNER: As far as the cause, as we know, regarding the turbine, first, the root cause of the turbine failure is still being investigated by the licensee. However, based on visual inspection, the licensee believes that one turbine blade failed due to high cycle fatigue. Four other blade failures have been attributed to fracture.

Regarding the fire, the fire at the generator --

MR. CARROLL: Has there been any history of high cycle fatigue based on NDE inspections of the turbine prior to this?

MR. GARDNER: There has been a history of blade failures at the plant, and I'll also be discussing that in a subsequent slide.

The fire at the generator exciter appeared to be the result of hydrogen leakage, explosion and burn. Hydrogen leakage appeared to have resulted from significant displacement of the turbine generator shaft and internals, causing the failure of the hydrogen seal oil system and generator hydrogen seals. The oil fire itself was limited and quickly extinguished.

Regarding the rad waste building basement flooding --

MR. WILKINS: I'm sorry. Was quickly extinguished automatically or by human beings?

MR. GARDNER: It appeared to have been automatically extinguished.

MR. MICHELSON: This was one blade or all five blades came off at once?

MR. GARDNER: It's postulated today, based on visual observation by the licensee, that one blade failed due to high cycle fatigue and then caused fracture fail of four adjacent blades.

MR. MICHELSON: But that all happened almost instantaneously.

MR. GARDNER: That is what is being postulated.

MR. MICHELSON: And that caused a displacement of the shaft of the --

MR. GARDNER: A mass loss which caused obviously an imbalance and the subsequent catastrophic failure.

MR. MICHELSON: This is the axial imbalance. It thrusted the shaft. How did that happen from losing just that many blades?

MR. CARROLL: I think he's saying it was a radial imbalance that upset the hydrogen seals.

MR. MICHELSON: This is over on the generator, though.

MR. GARDNER: No. This is lower pressure turbine No. 3 where we had the blade failure.

MR. MICHELSON: It was the stage closest to the generator.

MR. GARDNER: Exactly. Again, regarding the rad -
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MR. LINDBLAD: Excuse me, before you go much further. It's been my experience or I thought the assignments of AIT, in general, was when headquarters got results or got information about an event that suggested some lack of performance on the licensee's part.

What prompted this AIT? Was it concerned with licensee performance?

MR. GARDNER: I'll get into that in just a minute. I'll be discussing that. Again, approximately 500,000 gallons of water was released to the turbine building floors due to activation of fire protection systems and damage to a general service water pipe to the generator hydrogen coolers, fire protection system components, and turbine building closed cooling water system pipe.

A rupture of the supply line from the generator lube oil tank resulted in the release of approximately 17,000 gallons of oil to the turbine floors. Much of the water and oil on the floors drained to the turbine building sumps and then to the waste collector tank and floor drain collector tank in the basement of the rad waste building.

These tanks overflowed as --

MR. MICHELSON: How did it get from the turbine building to the rad wast building?

MR. GARDNER: Excuse me?

MR. MICHELSON: How did it get from the turbine building to the rad waste building?

MR. GARDNER: If you'd like, I have someone to answer that, if you'd like to go into more detail about that.

MR. MICHELSON: Sooner or later I'd like to hear how it got over there.

MR. GARDNER: We can do that now.

MR. MICHELSON: It's a fair distance, isn't it?

MR. GARDNER: It is. These buildings are interconnected.

MR. MICHELSON: But with what?

MR. GARDNER: By floors, by stairs, by drains.

MR. MICHELSON: These are abutting buildings.

MR. GARDNER: Yes.

MR. WILKINS: Abutting buildings, that really answers your question.

MR. MICHELSON: That's what I needed to know, yes. I thought it was freestanding.

MR. WILKINS: I'm thinking of a tunnel connecting them.

MR. KROPP: This slide here briefly describes the flow path of the water from the turbine building to the rad waste basement.

MR. MICHELSON: You better read it to me. My eyes are no longer that good.

MR. KROPP: Basically, I'll just describe how it got there.

MR. MICHELSON: That's good.

MR. KROPP: There was some interconnection, but very minimal, between the turbine building and the rad waste basement.

MR. MICHELSON: It was a short tunnel or something.

MR. KROPP: A few doors, a few floors, pathways, because the flooding --

MR. MICHELSON: But something went through tunnels, didn't it, or through chases?

MR. KROPP: Between the turbine and the rad waste buildings, it's just connected between the two buildings. I don't think there's any tunnel.

MR. MICHELSON: Penetrated right through the walls.

MR. KROPP: The drains, the floor drains.

MR. MICHELSON: But it's got to go through walls.

MR. KROPP: But most of the water came from the drain system on the basement to the rad waste building. The turbine basement is eight feet above the rad waste basement and there are no isolation valves. So eventually, even though there was no more pumping of the sumps to the rad waste building, the drains went to the appropriate tanks in the rad waste building. They overflowed and went to the sumps and filled up the basement, and that's the majority of the flow path.

MR. MICHELSON: And apparently there was some fire in the rad waste building as a consequence.

MR. KROPP: No. There was no fire.

MR. MICHELSON: It did not ignite when it overflowed.

MR. KROPP: No. I can give a little more detail.

MR. MICHELSON: No, that's good enough. Thank you.

MR. GARDNER: Thank you, Wayne.

MR. MICHELSON: What caused the rupture of the lubricating oil system?

MR. GARDNER: That's postulated to have been caused by a missile or by a hydrogen explosion.

MR. MICHELSON: Couldn't they tell where the leak was or the damage? The fire certainly didn't destroy the pipe.

MR. GARDNER: I couldn't hear the question.

MR. MICHELSON: Couldn't they tell where the pipe got ruptured or the tank or whatever caused the leak?

MR. GARDNER: The licensee at this time may have more information about it exactly. We just know that the lube oil pipe ruptured. I'm not sure we know the exact cause. John Stang may know that.

MR. CARROLL: Do you have a response to that?

MR. STANG: John Stang, NRR. When I was in the AIT and investigated, the lube oil piping was severed in a number of places. At most every bearing it was severed.

MR. MICHELSON: There must have been several missiles.

MR. STANG: No missiles. Vibration, I would assume.

MR. MICHELSON: Just to the turbine.

MR. FESSLER: We think we had vibration in excess of roughly 100 mils -- I'm sorry. Paul Fessler from Fermi, the Engineering Manager. We believe the high vibration caused those lines to leak and sever in several locations.

MR. CARROLL: It was welded pipe.

MR. MICHELSON: That won't solve the problem.

MR. FESSLER: It's flanged pipe, but it's --

MR. MICHELSON: Flanged and welded.

MR. GIPSON: Welded and flanged pipe. This is Doug Gipson. Let me just say that the eighth

MR. MICHELSON: The stage blades weighed roughly 120 pounds. Ten ounces change in mass on the shaft itself results in approximately a one mil change. So when the single blade failed and subsequently the other four blades failed, we're talking somewhere in the neighborhood of 500-

plus pounds of mass, which was close to the generator, obviously unbalanced the shaft, which would cause extreme eccentricity and vibration. That was demonstrated by the destruction on the exciter, which is on the far end of the machine.

The damage to the generator and most of the subsequent failure of the piping, both the lube oil system and the cooling water systems, I think, are attributed to the vibration and mechanical forces generated from the imbalance in the shaft.

MR. MICHELSON: But the displacements on the piping must have been very large, then. It's got to be somewhat flexible.

MR. GIPSON: It was large.

MR. MICHELSON: It's got to be extremely large not to rupture.

MR. CARROLL: It was jumping around.

MR. MICHELSON: It has to. I'm surprised they can do that much jumping.

MR. CARROLL: Is the oil piping and guard pipes like normal U.S. practice?

MR. FESSLER: That's correct.

MR. CARROLL: Did both the high pressure inside and the drain-back fail or was it mostly --

MR. FESSLER: No. We saw damage to both pipes, both sets of pipes.

MR. LINDBLAD: The guard pipe was not damaged.

MR. FESSLER: The guard pipe was also damaged.

MR. GARDNER: Maybe at this time it would be a good idea to show you some of the slides we prepared depicting the damage.

[Slide.]

MR. GARDNER: This is a general area of view. At one end, you can see the exciter, what's remaining of the exciter, and you can see the generator.

MR. MICHELSON: These were taken right after the event.

MR. GARDNER: Yes, sir.

MR. CARROLL: Is that a scorch mark?

MR. GARDNER: Yes, sir, on the bioshield. Yes. Actually, that's oil, I think. We felt the oil residue on it. So it appeared that hot oil had splashed up.

[Slide.]

MR. GARDNER: Again, you can see the exciter, the damage to the exciter quite clear here.

MR. MICHELSON: That was generator oil in that case, wasn't it?

MR. GARDNER: I think it was lube oil. It was not EHC fluid or anything like that.

MR. CARROLL: That's a common oil.

MR. MICHELSON: Yes. I was just trying to figure out which source, from the turbine side lubrication or the generator side.

MR. CARROLL: It's the same system, I would think.

MR. MICHELSON: It depends on the design.

MR. FESSLER: The hydrogen seal oil system.

MR. CARROLL: You're talking about seal oil.

MR. MICHELSON: Just in the hydrogen. That's what I thought. So it really got around, didn't it?

[Slide.]

MR. GARDNER: This is the hole in the casing on the LP3 the blade ejected through.

MR. MICHELSON: How thick is it at that point, the casing?

MR. GARDNER: Excuse me?

MR. MICHELSON: How thick is the casing?

MR. GARDNER: I think it's about three-quarters of an inch steel.

[Slide.]

MR. GARDNER: This is a No. 9 turbine bearing oil seal, half of which is on the MSR roof.

[Slide.]

MR. GARDNER: This is a general view of a neutral bus duct. You can see the heat damage to it.

[Slide.]

MR. GARDNER: This is another view of the bus duct damaged insulator.

[Slide.]

MR. GARDNER: This is pointing out an area or the edge of a melted area on the neutral bus duct where it actually melted.

[Slide.]

MR. GARDNER: This is some grating, the No. 4 LP valves. You can see the damage to the grating.

[Slide.]

MR. GARDNER: This is the blade piece that was ejected. It was found on grating near the No. 4 LP valves.

MR. LINDBLAD: Mr. Gardner, you showed a picture of the casing being penetrated. Was that normal, perpendicular, normal to the location where it failed or was there some axial direction, as well?

MR. GARDNER: I think we saw some axial displacement. Hal, if there's any --

MR. LINDBLAD: Typically, in a design, we pretend that it's limited to 25 degrees directivity. Do you know if it was more than 25 degrees?

MR. MICHELSON: Check that, because it's another good point.

MR. FESSLER: I can tell you that. That is, I think -- I believe it's within the 25 degree displacement from where the blade location would normally be.

MR. LINDBLAD: Thank you.

MR. MICHELSON: Where the blade finally ended up was at what displacement angular? It went out of the projectile. Maybe it did bounce, maybe it didn't. But where it finally dropped, what displacement did it have relative to the shaft?

MR. FESSLER: It stayed at roughly the same angles from where it ejected.

MR. MICHELSON: Thank you.

[Slide.]

MR. GARDNER: This is debris that's on the floor located between the neutral and the PT cabinets.

[Slide.]

MR. GARDNER: This is other debris on the floor near the oil room penetration.

[Slide.]

MR. GARDNER: This is the top half of the No. 11 oil seal.

[Slide.]

MR. GARDNER: This is a general view of the exciter. You can see the substantial damage that took place to the exciter.

MR. MICHELSON: Why did that occur?

MR. GARDNER: Vibration.

MR. MICHELSON: It could have happened before you got back to the exciter.

MR. CARROLL: No. The generator rotors are very rigid.

MR. MICHELSON: Yes, but their gap is so small, if they'd move much, they're just plowing right into the field right away.

MR. FESSLER: What we believe happened, the destruction that you see on the exciter due to mechanical energy, due to the vibration of the LP3 being transmitted through the generator into the exciter, the forces there were in excess or approaching a half-an-inch, four to 500 mils, given the mass that was ejected.

MR. MICHELSON: That thing flopped a lot, even though the shaft through the generator didn't flop enough apparently to --

MR. FESSLER: That's corrected.

MR. MICHELSON: Did it go into the winding?

MR. FESSLER: No. We've looked inside the generator and there's minor damage in the generator, but this was a much smaller mass.

MR. MICHELSON: Yes. What's the gap in the generator?

MR. FESSLER: I don't know that exact number.

MR. MICHELSON: It's usually a small number.

[Slide.]

MR. GARDNER: This is another view. I've got several views now of the exciter itself I will show you. This is a closeup.

[Slide.]

MR. CARROLL: You need a new bearing.

MR. MICHELSON: I think you need a whole new machine.

[Slide.]

MR. GARDNER: Yes. The exciter is considered totaled, I'm sure.

[Series of slides.]

MR. CARROLL: What coupling is that?

MR. GARDNER: Exciter coupling.

MR. CATTON: How big is it?

MR. GARDNER: Does anybody want to describe how big that is?

MR. CARROLL: It's about eight inches.

MR. GARDNER: About two feet in diameter, do you think?

MR. CARROLL: Yes.

MR. GARDNER: Maybe two feet in diameter.

[Series of slides.]

MR. GARDNER: This appears to be the low pressure No. 2 north end, I believe.

[Slide.]

MR. GARDNER: These are the five blades that are missing, five through nine. They're designated five through nine. There are about 64 eighth stage blades total.

I also noticed when I was out there -- I was out there when they removed the rotor assembly -- that there is a through-wall crack on Blade No. 1, I believe it was, all at the same location. You can see that the failures occurred right at about the same location on the blades themselves.

[Slide.]

MR. CARROLL: It tried to take some more, but it just took off the top of them.

MR. GARDNER: Excuse me? The eighth stage is the last stage of the low pressure turbine, right.

MR. WYLIE: Is it a 1,800 RPM machine?

MR. GARDNER: 1,800 RPM. Again, that's a closeup of the five blades.

MR. MICHELSON: Which was the one that broke in this line? The last one?

MR. GARDNER: In this orientation, I'm not sure. I assume it's the one furthest in this direction. Is that right, Paul? Can you tell?

MR. FESSLER: It would be the one furthest on the left.

MR. GARDNER: On the left.

MR. MICHELSON: Furthest on the left, first one on the end. That's what it looks like.

[Series of slider.]

MR. LINDBLAD: Are you going to discuss the blade failure itself a little bit later? I have a question or two.

MR. GARDNER: I'm going to give you some history of blade failures. Again, the licensee has not completed their investigation of the root cause.

MR. LINDBLAD: Let me ask my question and you can fit it in where you want. You described that the blade failed due to high cycle fatigue. That's really the first time I've heard people describing it as high cycle fatigue. Generally, they say low cycle fatigue when it fails before the expected end of life.

So how does one discriminate between low cycle fatigue and high cycle fatigue if it's designed for an endurance limit?

MR. GARLNER: I don't know if John Tsao can answer that. Right now, the information about high cycle fatigue comes directly from the licensee's visual inspection. At the time of the inspection or the end of our AIT, we had not determined any possible root cause yet. I don't know if you have an answer to that.

MR. TSAO: This is John Tsao from NRR. The one indication for high cycle fatigue is a fractured surface. You can see the marks. Also, another case is Susquehanna, where they had this high cycle fatigue that failed a blade due to vibration.

MR. LINDBLAD: What would it look like if it were low cycle fatigue?

MR. TSAO: I do not know.

MR. LINDBLAD: Thank you.

MR. CATTON: Probably the same low cycle fatigue, just unexpected high cycle fatigue.

MR. MICHELSON: That's what I thought.

MR. LEWIS: The difference between an old man and a young man depends on who is looking.

MR. SHACK: Normally, in low cycle fatigue, you see plastic deformation. There's plastic deformation in each cycle, where in the high cycle fatigue, the plastic zones are very, very small. It is a matter of degree.

MR. LEWIS: That's what I was going to ask. Presumably, one has inspected the face of the blade that broke and one knows where the crack initiated and can decide whether that is a zone of large plastic deformation and, therefore, fatigue. Is all that known now or is that what they're looking at?

MR. GARDNER: I think that's what they're looking at.

MR. CARROLL: Does Detroit Edison have anything to add to this discussion?

MR. LEWIS: Because they will know all that after they've examined it.

MR. SHACK: We sure hope it isn't low cycle fatigue.

MR. FESSLER: We have the five blades or what's remaining of the blades. Those have been removed from the rotor. We've taken them down to our metallurgical laboratory and we have begun the visual examination and the microscopic examination of those.

You can definitely tell where the fracture -- the change from high cycle fatigue to a rapid fracture. You can see that surface. We have not done enough investigation under a microscope to tell you that we know any more about the cause of that. There was some stimulus there, more than what was expected and designed for normal --

MR. LEWIS: You surely will know.

MR. FESSLER: We expect to know. That's true.

MR. LEWIS: You more than expect. You surely will know.

MR. FESSLER: We will have to know.

MR. LEWIS: Thank you.

[Slide.]

MR. GARDNER: This is identified as LP No. 3 north end, damage at the bottom of the diffuser.

[Slide.]

MR. GARDNER: This is also damage to the diffuser.

[Slide.]

MR. GARDNER: This is a decoupling area of LP3 south end bellows.

[Slide.]

MR. GARDNER: This is LP3 front stage eighth diaphragm blades, top half. These are the fixed blades.

[Slide.]

MR. GARDNER: Similar.

[Slide.]

MR. GARDNER: This is LP3 state eight front diaphragm diffuser.

[Slide.]

MR. GARDNER: And this is Blade No. 1. I think I spoke to that about the through-wall crack. That's it.

MR. DAVIS: I know from your inspection report that the seismic alarm went off in the control room. Do you know what acceleration level that alarm is set at?

MR. GARDNER: I believe we do.

MR. KROPP: It's set at .01 g's.

MR. MICHELSON: Is somebody going to tell us more about the fire or are you just about to do it?

MR. GARDNER: We're going to discuss the fire in a subsequent slide. I'll be moving right along because I know we've got a long way to go.

MR. SHACK: What took out the water service pipe? Was that a missile?

MR. GARDNER: The general service water pipe?

MR. SHACK: Yes.

MR. GARDNER: I believe it was either a missile or vibration. That's what I would have to postulate.

MR. CARROLL: Do you know?

MR. GARDNER: I'd like to talk now about the root cause of the conductivity problems.

MR. FESSLER: Excuse me, Ron. This is Paul Fessler. The question was what took out the service water piping. It was a combination of both. We had high vibration and we believe it had some impact on that piping.

MR. GARDNER: As far as RCS chemistry, conductivity and chlorides in the reactor increased due to severed condenser tubes. As the hot well level increases, it automatically rejects to the condensate storage tank and standby feedwater, which was feeding the reactor, takes its suction from the condensate storage tank. Therefore, the high conductivity, high chloride water was being introduced into the reactor.

MR. LEWIS: The fact is that we really don't yet know the cause.

MR. GARDNER: That's right.

[Slide.]

MR. GARDNER: As far as safety significance, the December 25, 1993 event resulted in significant damage, as you saw, to the Fermi 2 turbine generator system. However, reactor safe shutdown and safety-related safe shutdown equipment performance was not affected by this event. Gaseous releases resulting from this event were within the range of normal operations.

These releases occurred predominantly through the turbine roof vents that opened when this event took place. Also, liquids in the form of oil and water released to the environment as a result of this event contained no detectable radioactive contamination. This speaks to the water and oil mixture that was released under the roll-up door in the turbine building.

MR. MICHELSON: How much pressure does it take to lift the vent on the roof?

MR. GARDNER: I don't think we have that number.

MR. MICHELSON: What differential pressure to lift your vent?

MR. FESSLER: I think what happened on those is the diffusible link released on the vents and then the vents opened up. Spring.

MR. MICHELSON: If it got hot enough up there, yes. I thought maybe this was a pressure rise from release.

[Slide.]

MR. GARDNER: In regard to NRC action, within two hours of the event, Mr. Kropp, who was the SRI at the time, arrived at the site and started watching the licensee's activities. And because of the catastrophic turbine generator failure with complications, the NRC conducted an AIT from December 25, 1993 to January 19, 1994.

MR. LINDBLAD: Frequently, when the licensee hears an AIT is approaching, he is required to quarantine all the material.

MR. GARDNER: That's right.

MR. LINDBLAD: Was he required in this case to do that, too?

MR. GARDNER: Yes, sir, he was.

MR. LINDBLAD: Did that delay him a little bit or how much?

MR. GARDNER: No. We discussed that. I don't believe it significantly delayed it. The licensee had the posture that they wanted to go very slowly and deliberately. They knew they had to do a detailed analysis of root cause and they were very concerned that they might have people going up there and moving things that would prevent them from being able to do that.

So I think our impact on them was very minimal. I let them --

MR. LINDBLAD: Were they allowed to clean up and to pump down?

MR. GARDNER: They were allowed to clean up immediately in areas that were not pertinent to our review. We asked them, though, in those cases, for debris such as anchor bolts or things that were found in those locations, since the torrent of water washed a lot of debris all over the plant, we asked them to bag those items and take photographs, which they did.

MR. LINDBLAD: Thank you.

MR. MICHELSON: All over the plant. I assume you mean all over the turbine building.

MR. GARDNER: All over the turbine building, right. Excuse me.

MR. GIPSON: This is Doug Gipson. Not only did they request us to do that, we quarantined that Christmas day ourselves and placed security up on that area so that we wouldn't lose any potential evidence to determine the root cause ourselves. That was a requirement by the Region III Project Director when they talked to us and the resident.

MR. LINDBLAD: Thank you.

MR. GARDNER: Again, the size and scope of the AIT was expanded to assess licensee-ordered management efforts.

The NRC Region III mobile lab arrived on-site January 5, 1994. They conducted several confirmatory samples of in-plant flooded areas, including the rad waste building basement, and performed independent measurements of several environmental areas.

We enclosed in our report diagrams showing you where those samples were taken.

MR. MICHELSON: None of these safety-related areas were impacted, is that correct?

MR. GARDNER: That's correct.

[Slide.]

MR. GARDNER: I would now like to make a brief discussion regrading the event itself. I'll try to make this very brief.

On December 25, 1993, the plant received multiple turbine vibration alarms and a seismic alarm. Vibrations were felt in the control room and throughout the plant. These lasted from a minute-and-a-half to two minutes. Smoke and steam were observed in the turbine building.

The turbine tripped and the reactor scrammed. All safety systems functioned as expected. Main steam isolation valves closed on condenser high pressure. Reactor pressure was controlled via the safety relief valves and reactor core isolation cooling and reactor vessel water level via the standby feedwater system.

Operator error caused delay in placing the RCIC system in service. This was not detrimental to plant operation.

If there are any questions on that, I can stand on that.

MR. MICHELSON: What is the standby feedwater system?

MR. GARDNER: It's the system this plant has for issues such as this. Wayne, do you want to give more illumination on it?

MR. KROPP: It's two pumps, motor driven, that the licensee put in in the beginning of the construction.

MR. MICHELSON: In the feedwater system.

MR. KROPP: It's a separate system that takes the suction in the condensate storage tanks to the valves.

MR. MICHELSON: Where is it located?

MR. KROPP: It's located in the basement of the turbine building.

MR. MICHELSON: In the turbine building.

MR. KROPP: Yes.

MR. MICHELSON: And it was not impacted, apparently.

MR. KROPP: No. It functioned.

MR. CARROLL: I'd like to hear a little bit about the operator error.

MR. GARDNER: About 30 minutes after the event, operators were attempting to place the RCIC in the pressure control mode, as allowed by the EOPs. The EOP itself directs the operator to place the RCIC in the pressure control mode in accordance with an SOP, standard operating procedure.

In that procedure, the licensee -- excuse me. Before that, this licensec had previously determined that the operator on the valve that's needed to perform this function was too small to make the valve move due to pressure on the stem. That was recognized to be greater than the operator could overcome. They had changed the SOP requiring, before you operated that valve, to vent the pressure and then to operate the valve.

The operator did not perform the venting procedure and just tried to operate the valve. As expected, the valve would not operate. Subsequently --

MR. CARROLL: How do you vent it? Do you go down physically and open a vent valve or is this something you can do from the control room?

MR. GARDNER: I believe you physically vent it. Is that correct?

MR. MICHELSON: They've probably got a vent valve on the bonnet.

MR. GIPSON: I'll let our shift supervisor answer that question.

MR. POWEL: My name is Don Powel. I'm the Shift Supervisor on duty. The requirement is you have to go down to the reactor building basement area and vent the header where the line for RCIC ties back into the CST. We were looking to put it into a CST, the CST recirc, to use it for pressure control.

MR. MICHELSON: What valve was unable to function?

MR. POWEL: It's a test valve. It's the --

MR. GARDNER: It's the RCIC pump test return line valve.

MR. POWEL: Right, test return valve.

MR. MICHELSON: Why did that have to function? It's normally kept in the closed position, isn't it?

MR. POWEL: We were looking to use it for pressure control. RCIC would help us in minimizing the cycling of our SRVs by using RCIC to draw steam off the reactor. So we were looking to run it from CST back to the CST, which requires you to open the test return valve to the CST.

MR. MICHELSON: And then you were unable to open it.

MR. POWEL: That's correct, because the discharge pressure -- RCIC is approximately 1,100 to 1,200 pounds.

MR. MICHELSON: I understand why it would be, but I don't understand why this is allowed to be an indefinite -

- was this an indefinite or a very temporary fix?

MR. GARDNER: They were planning on changing the operator in the next refueling outage, which would have taken place in March.

MR. MICHELSON: That's a long time.

MR. CARROLL: But RCIC is fully functional.

MR. MICHELSON: Not apparently without the operator action.

MR. CARROLL: No, no, no. This particular alignment was simply to allow them to control pressure better.

MR. FESSLER: The alignment we're talking about is in the test mode of RCIC only.

MR. MICHELSON: When you needed RCIC.

MR. FESSLER: The injection mode -- the safety mode of RCIC was fully operable. It did not use this valve.

MR. MICHELSON: Is that what you were trying to get it ready to use?

MR. FESSLER: No. This was a test --

MR. MICHELSON: Just for pressure control.

MR. FESSLER: That's correct.

MR. MICHELSON: Then you would have to operate it.

MR. GARDNER: The licensee declared alert due to the fire potential in the turbine building and the local fire department was summoned to the site due to the potential for fire, but was not required to enter the plant.

As I said earlier, approximately 500,000 gallons of water and oil and 17,000 gallons of oil were released to the turbine building floors and the water and oil overflowed to the rad waste basement. Conductivity in the reactor increased due to severed condenser tubes. The maximum value reached was about 185 microMHOS.

Again, operators were slow to recognize the significance of high hot well level indications and take action to stop feeding high conductivity water to the reactor.

On December --

MR. CARROLL: What should they have done?

MR. GARDNER: They should have -- they did. In fact, they noted that hot well level was increasing. They knew they had a potential for turbine failure, with potential missiles having been ejected. CST level was increasing. The next shift that came on -- I spoke to the operators. The next shift that came on, they came on about an hour early, this was about two-and-a-half hours into the event, looked at the indications and said, gee, you ought to take action to secure your water that's feeding the hot well. They said you're right and they did it.

MR. MICHELSON: How much lubricating and control oil do you have in the plant? 17,000 gallons must be getting close to everything you had around the turbine. What is your total inventory? 17,000 gallons of lubricating and control oil is a lot of oil.

MR. GARDNER: What I was speaking to about the actions of the operator had nothing to do with control oil.

MR. MICHELSON: I realize that. I was asking about the 17,000 gallons on your slide.

MR. GARDNER: Sorry.

MR. POWEL: Our main lube oil reservoir is approximately 25,000 gallons. You had three pumps running at the start of the event.

MR. MICHELSON: You were perhaps very fortunate that you also busted water lines at the same time and not just the lubricating oil and the control oil.

MR. CARROLL: When were the circulating water pumps shut down? You weren't continuing to pump circulating water through the severed condenser tubes for very long, were you?

MR. POWEL: Circ water continued to run till 3:53 that afternoon. The event started at 1:15.

MR. MICHELSON: Probably just as well.

MR. LINDBLAD: And how big is your hot well? Didn't it overflow to the sewer at some time?

MR. CARROLL: It was rejected to the condensate tank.

MR. FESSLER: We have normal reject valves that would open on high level and that water was diverted back to the storage tank.

MR. GARDNER: I think Dr. Ornstein can add something to this.

MR. ORNSTEIN: Subsequent to the event, some members of the AIT observed sections of the plant and we verified that no electrohydraulic fluid had been lost.

MR. MICHELSON: This is just lubricating oil, then.

MR. ORNSTEIN: That's correct.

MR. MICHELSON: Not the EHC oil.

MR. ORNSTEIN: Right. The EHC oil was intact.

MR. MICHELSON: The EHC is the big problem, because that's very high pressure stuff. If it were to rupture, it squirts around in a hurry, as Switzerland found out.

MR. CARROLL: It's non-combustible, isn't it?

MR. FESSLER: That's correct. In fact, our main lube oil is non-combustible up to at least 350 degrees.

MR. MICHELSON: You've got hotter surfaces than that around.

MR. FESSLER: That's correct. Our fire protection system also activated at the time that a lot of water --

MR. MICHELSON: Once ignited, then you keep feeding it, then you've got yourself a real fire.

MR. CARROLL: This is a deluge system over the barriers and stuff?

MR. FESSLER: That's right. The deluge system activated.

MR. MICHELSON: It wasn't damaged at all.

MR. FESSLER: Parts of our fire protection system were also damaged in vari~us areas below the generator, but the deluge system did activate.

MR. MICHELSON: t was above, of course, and it was not damaged.

MR. POWEL: The deluge system is over the hydrogen seal oil system itself. The sprinkler systems activated underneath the generator to suppress the fire underneath the generator.

MR. GARDNER: I think John Stang from NRR can add information on that. He got it? Okay.

MR. ORNSTEIN: I think, Mr. Michelson -- can you give me a picture one time?

MR. GARDNER: A picture of what?

MR. ORNSTEIN: The turbine. I don't know if you have one in there to do it, Ron.

MR. MICHELSON: But your flash point on your lubricating oil was -- on your control oil was about 350 degrees Fahrenheit.

MR. GARDNER: I'm sorry. I didn't hear you.

MR. MICHELSON: The flash point on your control oil is about 350.

MR. CARROLL: Are you talking the same thing? Are you talking about EH oil?

MR. MICHELSON: Yes. EH oil.

MR. FESSLER: I was talking about the lubricating oil.

MR. MICHELSON: What is the EH oil flash point?

MR. FESSLER: I don't know that offhand, but --

MR. MICHELSON: That's the one I really worry about.

MR. FESSLER: All our EH system was not -- well, they're in a remote location from the area of the IP3.

MR. MICHELSON: They can't be remote and then get to the --

MR. CARROLL: Do you use a synthetic fluid in that?

MR. FESSLER: Yes, we do. I just can't tell you the manufacturer of the flash point.

MR. MICHELSON: It's a question of what flash point oil they're using.

MR. CARROLL: I think the ignition temperature is way up there.

MR. MICHELSON: I don't think it's all that high.

That's why I was asking.

MR. CARROLL: I'll find out.

[Slide.]

MR. ORNSTEIN: To give you gentlemen a little better idea --

MR. MICHELSON: The people in Switzerland found out when the flash is.

MR. ORNSTEIN: To give you a little better idea of where the sprinkler system is located. All around the turbine, you have this skirting. Right below, basically in each -- they call them bearing boats -- you have a wet pipe sprinkler system attached to risers right below here.

MR. MICHELSON: And that's a deluge.

MR. ORNSTEIN: No. That is a wet pipe sprinkler system, fusible links. The deluge system is on the second floor.

MR. MICHELSON: Is it a pre-action?

MR. ORNSTEIN: No, a wet pipe sprinkler system.

MR. MICHELSON: Wet pipe only. Okay. So it went to -- it should have gone off with this kind of heat.

MR. ORNSTEIN: That's correct.

MR. MICHELSON: Apparently it was not damaged or you might have had a little trouble delivering water.

MR. ORNSTEIN: There was a little bit of damage that we found on the turbine side. There were one or two sprinkler heads. That's all I could see. Now, the licensee might be able to tell you a little bit --

MR. MICHELSON: No pipe damage, such as the --

MR. ORNSTEIN: Not that I observed during the inspection. But the deluge system activated probably due to heat on the level below this. This is where the deluge -- the deluge system is on the level below that that protects the seal oil unit. Because of some heat in that area, riser detectors activated and it went off.

MR. MICHELSON: I thought you said fusible link.

MR. ORNSTEIN: No. That's -- the fusible links are on the sprinkler system around the turbine.

MR. MICHELSON: Okay.

MR. ORNSTEIN: The full length of the turbine. The area right below the turbine here on the second floor of the turbine building --

MR. LINDBLAD: You keep saying turbine, but, of course, we're looking at the generator, are we not?

MR. ORNSTEIN: I'm talking the turbine building. You're looking at the generator, that's correct.

[Slide.]

MR. ORNSTEIN: This area right here -- let me see. Let me get the orientation. I believe that's upside down. I believe this is the ceiling here. This is the area right below, which is also protected by the same wet pipe sprinkler system. As you can see, you had some heat and ignition for a small amount of time of some lube oil.

Now, to give you an orientation, I guess probably a hundred feet away from this area is your seal oil unit. That is protected by the deluge system that activated.

MR. MICHELSON: That seal oil system is -- now, where is the electrohydraulic control oil system? Is that the one you were referring to?

MR. ORNSTEIN: No, no, no, no.

MR. MICHELSON: Where is it?

MR. FESSLER: We have a separate actuator control system for each of our valves. There are 22 valves. There's the eight at the HP. There are six at the -- two for each LP and we have the bypass valves.

MR. MICHELSON: Where is it controlled?

MR. FESSLER: They're in various locations. A number of them are located above the reheater separators, which are along the length of the LPs.

MR. MICHELSON: So there are a number of them around the head end of the turbine, too.

MR. FESSLER: And a number of them are in front of the HP separated by a wall.

MR. MICHELSON: Were any of them damaged?

MR. FESSLER: No. None of those were damaged.

MR. MICHELSON: So it didn't get into that system at all.

MR. FESSLER: That's right.

MR. MICHELSON: Even though there was all this vibration, it didn't break any of the control lines and that sort of thing.

MR. FESSLER: That's correct. None of those were damaged.

MR. MICHELSON: You're lucky.

[Slide.]

MR. ORNSTEIN: To give you a little better look, this is -- the sprinkler system is basically all the way down your turbine. The sprinkler heads on the wet pipe system that were damaged that I found during the inspection, and the licensee may have found more, were back here around probably LP2 on the turbine.

Now, the deluge system that we're talking about is physically one floor below, over about a hundred feet below that.

MR. DAVIS: Can we get a copy of that, please?

MR. CARROLL: It's Page 75 of Tab 9.

MR. DAVIS: Thank you.

MR. CARROLL: We have got to speed up a little bit if we're going to get through this thing by 10:30, I think.

[Slide.]

MR. GARDNER: Real quickly. On December 26, in attempting to place the Division 2 shutdown cooling system in service, the B recirculation pump discharge valve would not close. Shutdown cooling was initiated using the A loop. The reason for this failure to close was subsequently determined to be broken wires in the motor itself between the limit switch and the torque switch.

MR. CARROLL: Totally unrelated to the event.

MR. GARDNER: Right, totally unrelated. Also, on December 26, the RHR warmup valve failed to close when the plant was being placed in the RHR shutdown cooling mode. This valve was used to warm up the RHR system prior to placing the system into shutdown cooling mode, also unrelated. On December 26, also, the plant went into cold shutdown.

MR. MICHELSON: When was the last time the valve was confirmed to be operable before this event? It must be cycled every 90 days.

MR. FESSLER: I'm sorry. Which valve are you referring to?

MR. MICHELSON: This is the one on the recirc loop that apparently had the broken wire, if I understood correctly.

MR. FESSLER: That was cycled in our previous shutdown.

MR. MICHELSON: You don't cycle them during normal operation.

MR. FESSLER: That's correct. Those are normally opened valves.

MR. KROPP: I think we said in our report it was September.

MR. MICHELSON: September of that same year, though.

MR. KROPP: Yes.

[Slide.]

MR. GARDNER: What I'd like to do now is go ahead and talk more about individual aspects of our inspection results regarding the turbine failure. First of all, prior to the event, reactor -- let me first say that the Fermi turbine has one HP high pressure turbine and three low pressure designated LP1, LP2 and LP3. I'll be using those designations.

MR. CARROLL: And nobody has said it yet, but it is an English electric turbine.

MR. GARDNER: It is an English electric turbine, yes.

MR. CARROLL: The only one of its kind in the United States.

MR. GARDNER: San Onofre.

MR. CARROLL: And San Onofre.

MR. GARDNER: Right.

MR. CARROLL: Is there European experience with this particular turbine?

MR. GARDNER: Yes, I believe so. If you'd like to talk --

MR. CARROLL: Same size and design.

MR. GARDNER: Our inspection report included overseas data with a lot of different turbines, including GE C-type turbines. First of all, again, prior to the event, reactor and turbine generator system parameters were normal. There was no indication of pending turbine generator failure. Again, the root cause is being investigated by the licensee.

Based on visual inspection, the licensee believes that one stage eight LP3 turbine blade failed due to high cycle fatigue. Vibrational electrical data recorded prior to and during the event indicated that failure was not due to turbine over-speed or electrical grid disturbances.

I'd like to talk now about some activities that the licensee did in the first refueling outage which took place in September 1989. During that outage, the licensee identified failed blades in the fifth stage of LP2. Subsequent inspection found damaged fifth stage blades in LP1 and LP3.

The failures were believed caused by wheel resonance and water accumulation. The licensee thought that this was the reason for the turbine balance and vibration problems experienced since 1988.

MR. CARROLL: Now, failed means broken?

MR. GARDNER: Yes. My understanding is failed means broken.

MR. CARROLL: When the blades failed, you had no indication of it operationally.

MR. FESSLER: No. We saw a definite change in vibration and phase angle of that vibration once the blade material had come off.

MR. CARROLL: And at that point, you shut down?

MR. FESSLER: At that point, we tried to determine what the cause of it was. We were uncertain.

MR. CARROLL: You kept running.

MR. FESSLER: "he vibration change was not significant enough to cause a turbine shutdown.

MR. CARROLL: Okay.

MR. GARDNER: As corrective action, fifth stage blades were removed from all the low pressure turbines. In addition, during this outage, the licensee identified that all LP eighth stage blades had sustained excessive wear of the lacing rods and lacing holes due to a phenomena known as tip rock and the wear was attributed to turbine operation for long periods of time on a turning gear.

MR. CARROLL: What would being on the gear have to do with it?

MR. GARDNER: Tip rock is a phenomena associated with slow revolutions of a turbine and that's what you'd have on the turning gear. As the blades come over the top, there would be a slight -- as they passed the top, they would have a slight --

MR. CARROLL: Okay. I've got you. I've got you.

MR. GARDNER: -- a flip and that would -- over 15,000 hours, I believe, is approximately how many hours they were in the turning gear. That caused excessive wear of the lacing spools and the lacing holes that the spools are placed in. These are on the latter part of the eighth stage blades.

The licensee noticed that all three LP turbines eighth stage blades exhibited excessive hole wear. To deal with it, they didn't have any additional or extra eighth stage blades, except for a spare set. They noted that the LP1 blades, eighth stage blades exhibited the worst lacing hole wear. So they changed those blades out with the spare set. Then their plans were to take the ones they removed out, have those refurbished. That would be weld up the hole and then have it redrilled.

Then they would be ready for RFO-2, the next refueling outage, and they would put those in the next LP stage that exhibited the worst wear. At the time, it appeared it would be LP2.

In December 1990, the licensee identified five stage four blades of LP3 that experienced fatigue failure. The failure was attributed --

MR. CARROLL: Again, failure means broke.

MR. GARDNER: Broke. The failure was attributed to high loading of stage four experience during stage five blades since stage five blades were removed in RFO-1. As corrective action, the stage four blades that had failed were removed and blocks were installed and pressure plates were fitted.

MR. LINDBLAD: Could someone tell me how many stages in the low pressure turbine?

MR. GARDNER: Eight.

MR. LINDBLAD: Eight. So we're talking about L-minus-three when we're talking about this failure.

MR. FESSLER: Yes.

MR. LINDBLAD: Thank you.

MR. CARROLL: How do you explain the fact that in these previous failures nothing went through the case and finally this time it did? Is there some explanation for that?

MR. FESSLER: Yes. Physically, the fourth stage and fifth stage blades are much smaller in mass and length. Also, there's an inner and an outer casing inside the exterior hood.

[Slide.]

MR. GARDNER: I'd like to speak to the second refueling outage which occurred in April 1991. Stage four blades in all the low pressure turbines were replaced with blades having understraps. These understraps provided continuous route interconnections. They also reinstalled stiffer fifth stage blades in all the LP turbines, and these also had the understraps.

Drains were cleaned to eliminate water induction into the turbine casing. Horizontal joints were repaired to reduce leakage. At this time, the refurbished LP1 blades were installed in LP2. Also, at this time, measurements were taken of the lacing hole wear for LP3.

In our inspection report, we identified that in reviewing that data that they took in RFO-2, we noticed that the licensee had identified excessive wear for Blade No. 27 in the eighth stage blades of LP3. It had been indicated on that data sheet that Blade 27 was acceptable only as long as the eighth stage blades for LP3 were changed out in RFO-3.

RFO-3 came about and the licensee did a visual inspection. Based on their visual inspection, they determined that the lacing hole wear had not increased, the extent of it had not increased, it was nominally the same as had been noted in RFO-2, and decided not to replace the eighth stage blades and that they would put those in or do that change-out in RFO-4.

In our inspection report, we identified that the licensee's decision not to replace the eighth stage blades may have been a precursor or a causal factor. Subsequent to the AIT, in the week of February 15, I went to the plant. I observed the licensee's removal of the LP3 eighth stage -- well, the whole rotor and I looked at LP3 eighth stage blades.

Blade No. 27 is still intact. It's somewhat damaged, but the lacing spool pieces are still installed. There is no indication of lacing spool failure. So that doesn't appear to have been attributed to this event.

As indicated, though, by everything I've said previously, the licensee experienced repetitive vibration problems during the 1988-89 time period. The licensee made numerous repairs and inspections of the LP turbines, but was not fully successful in eliminating these problems.

The licensee retained an upgraded startup testing vibration monitoring instrumentation to help in their vibration analysis. The licensee's inability to maintain the turbine vibration consistently at acceptable levels resulted in a decision to disconnect the automatic high vibration trip in 1989. Subsequently, the licensee has been moderately successful in reducing turbine vibration to the four to six mil range.

MR. CARROLL: Let's put that statement in perspective. This is a philosophical issue as to whether one has had vibration trips in utility turbines. Many utilities do not have such trips. The one I used to work for didn't on the basis that it was the potential source of unreliability and that the operator knew where the red handle was.

MR. DAVIS: There is no regulatory requirement for it.

MR. CARROLL: No.

MR. GARDNER: That's right.

[Slide.]

MR. GARDNER: At this time, I'd like to switch subjects and talk about RCS chemistry. First of all, I'd like to talk about before and after. Regarding high conductivity before the event, they were operating at about .08 microMHOS and after the event they got up as high as 185 microMHOS.

In the area of chlorides prior to the event, they were less than two parts per billion. After the event, they reached approximately ten parts per million. Concerns for these high conductivity and high chlorides deal mostly with the control rod drive seals and the reactor internals.

The licensee performed two temporary modifications which we overviewed or evaluated. One was a condensate return tank to control rod drive seal modification, temporary mod, and then another -- and then back to the CRT, the reactor water cleanup system, using temporary demineralizers. This was a low flow system and it provided cleanup of the seals, but didn't, in the large sense, provide the cleanup of the whole RCS.

So to take care of the overall problem with the conductivity and the chlorides, the licensee installed a second temporary mod. This was planned originally. This was a mod that would connect the reactor water cleanup to side stream portable demineralizers, larger demineralizers, and involved higher flows. This resulted in significant cleanup of the RCS chemistry situation.

MR. LINDBLAD: In what period of time?

MR. GARDNER: Steve, do you remember?

MR. LINDBLAD: How long did the reactor see 185 microMHOS?

MR. GARDNER: I think it was a matter of days, if not a week or two. A week or two, I would imagine.

MR. LINDBLAD: And the same for the chlorides.

MR. GARDNER: Yes.

MR. SEALE: I assume you're back to an acceptable level of chlorides now.

MR. GARDNER: Steve, do you know where they were the last time?

MR. ORTH: Steve Orth from Region III. Last I heard, the plant was at approximately 1.4 microMHOS and the chlorides were a little under one ppm. Is that correct?

MR. CARROLL: One ppm.

MR. ORTH: Yes.

MR. FESSLER: Yes, that's correct.

MR. CARROLL: We're running out of time. What are the remaining subjects?

MR. GARDNER: I have two subjects to discuss. One is fire protection systems and how they perform and the second is an overview of the water management system, how they dealt with the water in the rad waste building basement, and some concerns we are looking at regarding the reactor building, specifically the four corner rooms.

MR. CARROLL: Okay.

MR. GARDNER: Do you want me to skip any part of this?

MR. CARROLL: Well, I think we can skip the water management and read your slide.

MR. MICHELSON: What do the four corner rooms have to do with the event?

MR. GARDNER: Nothing. But as part of our inspection, we were curious to see whether or not there was any communications of water from the rad waste building basement to the reactor corner rooms. We sent someone down to look at it. We saw no problem, but in looking at it, we were curious as to what was keeping the communication from taking place.

We looked at the drawings, etcetera, identified that the drains connecting the four corner rooms to the rad waste building basement, each have a check valve. We asked about any testing that the licensee had done or PMs on the check valves.

At the time of the inspection, we hadn't determined whether anything had been done with them, except probably an installation checkout.

MR. MICHELSON: Yes.

MR. GARDNER: We are looking at this as just an issue that we need to look at.

MR. MICHELSON: It's a very important issue.

MR. GARDNER: I'll stop after fire.

MR. CARROLL: Yes.

[Slide.]

MR. GARDNER: I only have a few comments here. Basically, the automatic suppression and fire alarm systems operated as designed. We have one thing we'd note, and that was that the fire brigade responded as a team approximately 37 minutes after the event. This did not effect the outcome of the event or prevent the licensee from quickly dealing with the fire.

However, I believe we think that for future fires, it would be better if the full fire brigade is able to respond as a team in a more quick manner.

MR. MICHELSON: Is there any reason why the full one didn't respond?

MR. GARDNER: There are a number of reasons, part of it having to do with the location of people when it occurred, the inability to get to certain areas for assembly, the licensee's decision on when to call the full fire brigade into play.

MR. MICHELSON: This full means only on-site.

MR. GARDNER: Yes.

MR. MICHELSON: Okay. I thought they responded much faster than that for any fire. The fire people -- when we get into these one-hour barrier arguments, yes, they're in 20 minutes and it's all over with.

MR. DAVIS: Twenty minutes is typical.

MR. MICHELSON: Here it took 37 minutes to get them all there.

MR. CARROLL: I don't know what "full" means.

MR. MICHELSON: I don't either.

MR. CARROLL: As opposed to "partial."

MR. MICHELSON: That's right. I don't know if we've got time to get into it, but it's interesting.

MR. DAVIS: This is after the event, not after they were notified.

MR. POWEL: I could answer some of those questions, if you want to go into that. When the event started, the response to the operators was to immediately go out into the turbine building. The people in the building adjacent to the control room could not get out the door because of the pressure transient in the turbine building. They could not get the door open.

They immediately came back into the control room where they felt a certain safety factor, because, as you can imagine, the building was shaking at that time. They reported to us they saw steam and smoke, in that order.

Operators in other areas of the plant responded immediately to come up into the turbine building to find out what was going on. They immediately left for their own safety concerns and proceeded to the alternate OSC, which is alternate dress-out area.

MR. CARROLL: Dress-out for a fire.

MR. POWEL: For a fire brigade. So at this time, I had half -- part of my fire brigade in the control room concerned about the conditions in the turbine building and part at the alternate OSC.

Approximately ten to fifteen minutes into the event, the fire brigade leader is trying to get his people dressed out and into the turbine building. He came to me and requested permission to enter the turbine building, which we evacuated immediately, to proceed in evaluating the plant conditions.

Again, the people in the control room could not exit the area because they didn't understand the conditions out into the turbine building. The control room doors lead right to the turbine building. Subsequently, approximately 37 minutes into the event, we got the fire brigade leader, who was in the control room, out to his people, out into the control room, where he used some of our own respirator equipment in the control room, that we have stored in the control room.

MR. MICHELSON: Did you ever estimate the pressure you thought the turbine building might have gotten to? Since you were unable to open the doors, that gives you at least a bounding condition.

MR. POWEL: Our normal dress-out time is approximately five --

MR. MICHELSON: No, no, no. The pressure.

MR. CARROLL: The pressure.

MR. MICHELSON: You said you couldn't open the door.

MR. POWEL: That's correct.

MR. CARROLL: For how long?

MR. MICHELSON: How much pressure do you think was in the turbine building?

MR. POWEL: When they got back over there, when they got to the control room, which took them a few minutes -- and we were also evaluating and responding to all of the alarms and everything that were happening at the time. We evaluated the turbine building pressure. It spiked up immediately and then came down. It tripped off turbine building high vac. We had a discussion approximately five to ten minutes into their restart turbine building high vac.

One, which isn't stated in here, was the main reason was to prevent a ground release, because at that time, we thought -- a thought that was going through my mind was we possibly had a major steam rupture and took out the lube oil system, which was causing the vibration problems.

So the fire condition wasn't our major concern at that time. It was concern of the safety of the people, possibly to radiological conditions, not necessarily to fire, in that sense.

MR. MICHELSON: How long were you unable to open the door?

MR. POWEL: At that particular time, I didn't send the people to go try to open the door. They probably could have opened it up a couple minutes or a minute afterwards. The spike just showed a -- it was just a spike on the recorder.

MR. MICHELSON: Did you have a monitor on the environment?

MR. POWEL: In the turbine building, yes.

MR. MICHELSON: And you got a trace of that on a chart or something.

MR. POWEL: That's correct. We looked at that and it was just a momentary spike up, but it was long enough that they could go from their seats and walk over to the door and not be able to get it open.

MR. MICHELSON: What did it spike up to?

MR. POWEL: It went above the chart indication, which I believe is 2.5 PSI.

MR. MICHELSON: It exceeded 2.5.

MR. POWEL: 2.5 inches of water.

MR. MICHELSON: Inches of water. Well, that's nothing, but it's something on a door, of course.

MR. CARROLL: Tell me about the hydrogen fire. That's something I'm always interested in. That hydrogen was released. It caught fire. I saw on one of the slides an explosion.

MR. GARDNER: I think John Stang can speak to that, if you'd like.

MR. CARROLL: All right.

MR. STANG: Put the picture of the exciter up.

MR. GARDNER: This picture, John, up here?

MR. STANG: Yes. That would probably best tell the story.

[Slide.]

MR. STANG: What was your question?

MR. GARDNER: Explain the hydrogen fire, how it ignited and what kept it from being a bigger conflagration than we had.

MR. CARROLL: Was there an explosion?

MR. STANG: Yes, sir. We believe there was.

MR. CARROLL: Fast-burning or detonation?

MR. STANG: Detonation followed by fast-burning. If you look at the intersection where you would have lost your seal oil between the exciter and the generator, it looks at that point where there was an explosion based on the displacement of the couplings and everything else.

MR. LINDBLAD: Was the hydrogen still burning when the operators accessed the turbine building?

MR. STANG: No, sir. There was no fire at all in the turbine building. In the interviews with the fire brigade leader, all they saw was water running.

MR. GARDNER: They did see one little small fire on some brushes on the exciter. They took a CO2 extinguisher and put that out. There were a couple of pieces of debris on the floor that were smoldering, if not burning, and they kicked water on it, basically, and put those out. That was it.

MR. MICHELSON: A flash point of 350, that's the kind of fire you get. It burns for a while, but it quenches out.

MR. CARROLL: While nobody was in the building, you're postulating that the hydrogen was released. What was the generator pressure by the time they got in the building?

MR. STANG: You mean the hydrogen pressure of the generator?

MR. CARROLL: Yes.

MR. STANG: It's a differential of about 20 pounds, I think, between the seal oil unit and the hydrogen, I believe, during normal operation.

MR. GIPSON: That's correct. It's right around 70 pounds if you just look at the hydrogen pressure.

MR. CARROLL: And the hydrogen pressure had all bled off by the time anybody got in the building.

MR. GIPSON: Right. Let me just point out to you that our normal operating practice is to run with our hydrogen supply system isolated from the generator. So the hydrogen supply system was isolated from the generator and whether or not we had a detonation or an explosion as the hydrogen leaked out of the machine, it would have burned, detonated, burned, whatever, and it was a fixed amount of hydrogen.

We think that happened fairly rapidly. I think Mr. Stang would agree with that, based on the volume and the pressures that we think it leaked out and burned rather -- almost flashed, if you will.

MR. MICHELSON: Do you have some kind of a leakage arrangement to keep the pressure up?

MR. CARROLL: Let me ask you -- go ahead.

MR. MICHELSON: I just wondered if he -- you can't just shut the hydrogen off during normal operation.

MR. STANG: They charge it daily, I think.

MR. CARROLL: You charge it when you need to.

MR. GARDNER: They charge it based on rounds approximately every day.

MR. MICHELSON: If you've got a very small leak rate, you could do it.

MR. CARROLL: That's what you're supposed to have on a generator.

MR. STANG: They check it, I believe, once per shift.

MR. CARROLL: That's normal practice. Let me ask a hypothetical question about something that always worries me, having lived through a generator with a hole in the side of it with a flame coming out of it. Would you have tried to put a fire out if you had been able to get in there and seen flame coming up from wherever, hydrogen burning?

MR. GIPSON: Mr. Stang can speak to this, too. There are fire systems, deluge systems, automatically actuating when this event occurred. It's hard for us to postulate what the fire brigade --

MR. CARROLL: That's right.

MR. GIPSON: But I would tell you that there is a fixed amount of hydrogen in the machine and on a detonation or a hydrogen fire, it burns very rapidly. By looking at the damage to those seals and the damage to the hydrogen system, we think it leaked out very rapidly, at least that's the conclusion. It's hard for us to postulate what a fire brigade would do.

I would tell you that they were thinking reactor safety first and then personnel safety. I'm sure the decision would be based on personnel safety on a large fire situation, on how they could deal with or not.

MR. CARROLL: In an enclosed building, if it's just hydrogen burning, I think you ought to let it burn, because it isn't going to do anything bad.

MR. MICHELSON: They aren't going to do anything with it anyway.

MR. CARROLL: And if you put it out, you run the risk of having an explosion. That was my trick question.

MR. MICHELSON: How far was your isolation valve on the hydrogen line to the proximity of all this event?

MR. GARDNER: There are two isolation valves. There is one at the hydrogen charging panel and there's one at the outside of the turbine building itself. Both of these valves are secured after charging.

MR. MICHELSON: You keep both of them closed.

MR. GARDNER: Both of them are closed until they're charged.

MR. MICHELSON: So even if you had ruptured the line, it still would have been okay.

MR. CARROLL: I think unless we've got one more real important question, we're going to have to move on to our break and the McGuire event.

MR. SEALE: I have just one.

MR. CARROLL: Go ahead, Bob.

MR. SEALE: I vaguely recall that about ten years ago or so, San Onofre had a rash of turbine problems. Was it sibling turbines to these that had those problems at San Onofre or do you know?

MR. ORNSTEIN: I'm not familiar with the event that you're talking about. San Onofre Units 2 and 3 have similar turbines. My name is Hal Ornstein from AEOD. Unit 1 is different. I just don't know.

MR. SEALE: And I don't know which ones they were.

MR. CARROLL: Does Detroit Edison have comments on this?

MR. FESSLER: I can tell you San Onofre went into service roughly the same time that we did, which means they've been in service about ten years. So this is t years ago. They were just placing their turbine in service at that time.

MR. LINDBLAD: And as I recall, after this recent upgrading, you have not been able to get the valves fully opened, inlet valves, control valves fully opened to achieve an upgraded rating. Is that correct?

MR. FESSLER: The reason we're at 93.5 percent power is because we have a problem with vibration on our turbine control valves if we were to open them up more than the 93.5 percent power level.

MR. LINDBLAD: Yes. That's what I heard. Thank you.

MR. DAVIS: Do you have a schedule for restart?

MR. FESSLER: Right now our estimated date for restart is October 1, but that's based on several things. We don't know the root cause yet and that's the major issue that we don't have a full grasp of yet.

MR. DAVIS: Thank you.

MR. CARROLL: I would like to thank the staff and the Detroit Edison delegation for a very interesting and useful presentation. Are we going to take a break? We're running 15 minutes late.

MR. KRESS: Yes. Let's take a 15-minute break.

[Recess.]

MR. KRESS: It's time to reconvene our meeting. At this point, we're scheduled to get a briefing, I guess, on the loss of off-site power and steam generator dry-out event at the McGuire plant. Jay, do you have some introductory words?

MR. CARROLL: Not really. You just said them for me, except that --

MR. LINDBLAD: We're two days late.

MR. CARROLL: Except that I forgot to mention when we closed the last session that we do have a 15-minute video set up showing in more detail what happened at Fermi. So I guess we'll show that a few minutes after we break for lunch, if people want to sit here and eat their lunch and watch more of the Fermi event.

MR. CATTON: You have to trade off earthquakes.

MR. LINDBLAD: Yes. That's in competition with the meeting in Room 422 for North Ridge with Mr. Bagchi.

MR. CARROLL: So maybe we can find another time to look at the video, then.

MR. CARROLL: Is it a pretty good video, Al?

MR. CHAFFEE: It's an okay video, but you saw a lot of the pictures. They showed a lot of it. I think what you'll find when you see it is it will give you a few more angles, but my suspicion is you've seen most of what you're going to see in the video.

MR. CARROLL: Maybe we don't really need to look at it. Okay, Al.

MR. CHAFFEE: I just wanted to introduce Eric and talk about some of the folks we have here and say a few things. You will notice that in this particular case Eric is doing the brief on this event that occurred at McGuire. We do have the AIT Team Leader here, which is Mark Lesser, and we do have a number of other folks, some of whom have been closely involved in this and were on the team.

We have Rinaldo Jenkins from the Electrical Branch. We have Stacy Rosenberg, who is here from NRR from the Risk Assessment Branch. Vic Nerses is the Project Manager, he's here. Chu Liang is here from Reactor Systems, as well as Mark Caruso. We also have Pat Eng, who is here from Human Factors. From the cross-section, you can see there are a lot of different areas of interest in this particular event.

So at this point, I will turn it over to Eric, who will try to take us through the sequence of events. At the end of that, which he will try to do quickly, he is going to talk about several of the issues that came up out of the event.

MR. CARROLL: And we also have some Duke people, do we?

MR. CHAFFEE: I'm sorry. You're right. We have some Duke folks here.

MR. SHARPE: My name is Robert Sharpe. I'm the Regulatory and Compliance Manager at McGuire. I have with me Dr. P.M. Abraham from our Nuclear Engineering Group.

MR. CARROLL: Thank you.

[Slide.]

MR. BENNER: Good morning. I'm going to start out by doing a much more abbreviated sequence of events than what is in your package, so that we can get to the issues. I may reference back to the detailed sequence of events as we go through those issues.

[Slide.]

MR. BENNER: This is a diagram of the McGuire switchyard, which is what we will start with. At 10:06 p.m. on December 27, the 525 kilovolt 2B bus was lost due to an insulator failure. Here is the 2B bus. The insulator failure was in the area of this disconnect.

Thirty seconds later, Bus 2A was lost on over-current, when breaker protection schemes opened these two breakers. At that point, the unit was in a loss of off-site power.

MR. LINDBLAD: Let me go back to the insulator failure. Was that a line-ground fault and did it open the 2B?

MR. BENNER: It was a phase differential current.

MR. LINDBLAD: All right. Did it operate the generator 2B breaker?

MR. BENNER: The generator output breaker? No, it did not, I don't believe.

MR. LESSER: Yes, it did. It operated the two -- I'm Mark Lesser from NRC Region II. I was the AIT Team Leader. It opened the two switchyard breakers and the 2B generator output breaker.

MR. LINDBLAD: Thank you.

MR. BENNER: As a result of the event, aux feedwater started injecting. You add some steam loads that remained open on the loss of off-site power and you had your turbine-driven and both your motor-driven aux feedwater pumps injecting, resulting in approximately 400 percent aux feedwater flow.

This caused an RCS depressurization. Seven minutes into the event, you got an SI on low pressurizer pressure because of the cool-down and resultant depressurization.

A minute after that, the B steam line reached the set point for MSIV closure. The MSIV closure signal was actuated and the B MSIV failed completely closed. Manual attempts to close the valves were unsuccessful. Because of the --

MR. CARROLL: You're going to tell us why that was eventually?

MR. BENNER: Yes. That is one of the six issues that we plan to discuss.

MR. CARROLL: Okay.

MR. BENNER: As a result of the continuing depressurization, the operators transitioned into their emergency procedure for steam line break outside of containment, which dictated that they isolate aux feedwater to what appeared to be faulted steam generator.

Also, per procedure, the operators started cycling --

MR. CARROLL: Why do you say that? Didn't they know that the MSIV hadn't closed? Why do you say it appeared to be a faulted steam generator?

MR. BENNER: Well, because there wasn't a break. We didn't have a break. We did have a steam leak, but we didn't have a steam line break.

MR. LINDBLAD: But did they get indication of --

MR. BENNER: All the indications were consistent with what you would see for a steam line break.

MR. LINDBLAD: With the MSIV still open.

MR. BENNER: Yes.

MR. CHAFFEE: I'm not sure that they had indication that the MSIV was still open.

MR. LINDBLAD: That's what we're asking.

MR. CHAFFEE: Right.

MR. LESSER: Yes. The operators were aware that the B MSIV did not fully close and as they were proceeding through their EOPs, the symptoms were that of continued depressurization of the secondary side with an MSIV closure signal, which directed them into a steam line break outside containment EOP.

MR. MICHELSON: Did they have a stem indication of the position of the valve?

MR. CARROLL: These are Westinghouse.

MR. MICHELSON: Yes, but you still have a stem.

MR. LESSER: Yes. The valve is an Atwood Morrill 14-inch stroke. They have a limit switch actuated basically on the --

MR. MICHELSON: Off the stem.

MR. LESSER: Off the stem. And it did not actuate.

MR. MICHELSON: It did not actuate because it didn't get -- so they knew it was hung up somewhere in between fully open and fully closed.

MR. LESSER: Yes, sir.

MR. BENNER: I'm moving on. Also, per procedure, the operators were directed to cycle the PORV, the power-operated relief valves, to maintain the differential pressure across the tubes in Steam Generator B at less than 1,600 psi. The maximum delta P across those tubes reached was 1,981 psi.

After 40 minutes of cycling that PORV and resultant mass addition to the pressurizer relief tank, the pressurizer relief tank rupture disk ruptured. This resulted in some ice condenser doors opening.

At 11:42 p.m. that same evening, off-site power Bus 2A was restored. Three minutes after that, the wide range level indication for the B steam generator indicated that that steam generator was dry.

On the morning of December --

MR. CARROLL: How did they get Bus 2A restored? What did they do?

MR. LESSER: Bus 2A tripped on an over-current condition after checking it for any faults. They identified there were no faults on it and were able to reenergize that bus simply by closing breakers.

MR. CARROLL: Okay.

MR. BENNER: at 12:32 a.m., the emergency buses were realigned to off-site power. At 1:37 a.m., the A reactor coolant pump was started, getting them out of a natural circulation situation.

At 6:22 a.m., a second source of off-site power was restored, basically terminating the event.

[Slide.]

MR. BENNER: The issues that I intend to discuss are the following; electrical system design, MSIV or main steam isolation valve operability, procedural adherence, document control, corrective actions from a previous event. In 1991, McGuire Unit 1 experienced a loss of off-site power with subsequent safety injection due to some steam loads and aux feedwater flow. In that situation, the main steam isolation valves did gc closed. The final issue will be a risk assessment that was done of the event.

MR. DAVIS: You didn't mention it, but I presume the diesel generator started successfully.

MR. BENNER: Yes. There was no problem with the diesel generator starting or loading.

MR. DAVIS: Thank you.

[Slide.]

MR. BENNER: The insulator failure on Bus 2B was caused by deterioration of cement in the insulator.

MR. LINDBLAD: It's not clear to me how that causes insulator failure.

MR. BENNER: I'm going to get a little more into it momentarily.

MR. LINDBLAD: Okay.

MR. CARROLL: Those pictures are towards the back of your handout.

MR. BENNER: These pictures are all included in your package.

[Slide.]

MR. BENNER: This is the insulator type that they had at the plant for the event. I have a closeup of the failure mechanism in here somewhere.

MR. CARROLL: Stack individual cones.

MR. BENNER: The one previous to that.

[Slide.]

MR. BENNER: There were tensile stresses forces in the axial direction created by cement expansion or growth. This is partially an aging factor. These insulators were approximately 15 to 20 years old. It appears in the past that the licensee had had problems with some of these insulators in their 230 kilovolt switchyard. At that time, they went and inspected the insulators in this switchyard and found no apparent damage, cracks in any of the insulators.

MR. LINDBLAD: Was this insulator a post? Did it have column loads on it? When it cracked, did it drop something?

MR. BENNER: Yes.

MR. LINDBLAD: In tension or in compression?

MR. BENNER: In tension, I believe.

MR. LINDBLAD: All right. So this was a supporting -- hanging a wire down below.

MR. BENNER: Yes.

MR. LINDBLAD: Thank you.

[Slide.]

MR. BENNER: Bus 2A was lost for multiple reasons. One was a failed turbine run-back in conjunction with what the AIT found to be inadequate relay coordination. The system is designed such that -- I can go back to this diagram.

[Slide.]

MR. BENNER: That upon loss of one of these lines, the turbine is supposed to run back to approximately 56 percent power, such that you don't overload the other line. The original design of the plant was that that was supposed to occur in 15 seconds. There is a relay to protect some of this equipment from over-current. The 51-L backup non-directional relay, which picks up at the 30-second mark.

A modification installed in 1989 changed the run-back circuitry from 15 seconds to a three-minute run-back time. As a result of that -- in this event, that point is moot because the run-back failed due to a failed resistor in the turbine run-back system, a card.

But the AIT examined this a little closer and in comparing curves for the pickup times for the relay and the run-back times, it seems to be somewhat of a horse race as to whether or not you're going to get the run-back successfully before you get the trip.

The unit did have a fault on one line in 1991 and the run-back system worked correctly to prevent a loss of off-site power.

MR. CARROLL: So the point is that if Duke had left the system like Charlie had designed it, they wouldn't have this problem.

MR. BENNER: There is some question as to tripping breakers up here as opposed to having a scheme which would cause you to trip your generator output breaker. You're basically saying that if the turbine run-back fails, you're going to get a loss of off-site power. Subsequent to the event, the licensee removed the input from that 51-L relay, because there are 51-T relays which, in the case of a failure of the run-back circuit, will cause the relevant generator output breaker to open, such that you will still preserve one of your sources of off-site power.

The fixes for the event were, as I just said, they deleted that input from the 51-L relay. The digital electrohydraulic control card that had the resistor failure, the resistor was replaced and the licensee went back and checked all the other cards, found no other resistor failures, and also did a functional test of the run-back on Unit 2.

In addition, the insulator, the failed insulator has been replaced with a lock solid core type insulator instead of the multi-cone type insulator.

Are there any questions on electrical before I move on?

MR. SEALE: As I understand this layout, then, under the way the relays were set up, there was literally no advantage to Unit 2 because there was a Unit 1 there.

MR. BENNER: Short-term.

MR. SEALE: There was no electrical interconnect.

MR. BENNER: Right.

MR. SEALE: Because that was the only --

MR. BENNER: There are some manual actions that can be taken.

MR. SEALE: Okay. Thank you.

MR. BENNER: As part of their requirements for general design criteria. But you're right. Immediately Unit 1 was effectively not there.

MR. LINDBLAD: As I understand what you said, that the switchyard protection system worked properly, but the generator protection system had the failure in it. Is that right in terms of the electrical relaying?

MR. LESSER: Let me just explain that. Following the insulator failure and the loss of the 2B system, the only other failure that occurred was the turbine run-back due to a circuit fault and because the 2A remained overloaded and tripped on over-current. All the relay protection actuated as designed.

MR. LINDBLAD: If I can separate relay protection into that which is out in the switchyard and that which is in the generator, the switchyard relays did not have to operate. Is that right? They just actuated the breakers.

MR. LESSER: The switchyard relays were required to [illegible]te on overload and they opened up the --

MR. LINDBLAD: That's right, on 2A.

MR. LESSER: Yes, sir, but not on --

MR. LINDBLAD: The 2B opening was part of the ge[illegible]ator protection system.

MR. LESSER: Yes.

MR. LINDBLAD: The phase differential is a generator protection relay.

MR. LESSER: Yes.

MR. LINDBLAD: Thank you.

MR. BENNER: Is that all?

MR. LINDBLAD: Yes.

[Slide.]

MR. BENNER: Moving on to the next issue of main steam isolation valve operability. The basic cause of the failure of the MSIV to close was mechanical binding. I will bring up a diagram of the valve.

MR. CARROLL: I was thinking of the other type, Carl, when I was worrying about stems.

[Slide.]

MR. BENNER: The clearance tolerances between the valve yoke rods, which are right here, and the spring plate guides, which are located around the spring plate, had been set cold on these valves. The vendor recommendations were that you should set these clearances at normal operating temperature.

The licensee had multiple opportunities to incorporate this vendor info. In 1991, Duke Power received a revised vendor manual which had these specifications for clearances in them. The clearance recommendations were incorporated at Catawba, which was being constructed at the time, but they weren't incorporated on McGuire.

In 1992, because of some problems in matching up replacement part numbers, McGuire requested a revised vendor manual. At that time, plant personnel felt that the recommended clearances didn't need to be incorporated at the site since they hadn't had any problems with the valves closing in the past. At the time of this event, Engineering was still evaluating whether or not that was a prudent decision or not.

These valves are air to open, spring to close. There are springs located around the yoke rods, which, when the air -- when you have air to open, move this plate upwards, you compress these springs such that when air is removed, the springs will cause the valve to go closed.

When the valves were first installed, the licensee's commitment had been for a five-second stroke time. As a result of having a little difficulty maybe meeting that stroke time, an air assist was put on to assist in closing the valves.

At a later time, a mod was prepared to upgrade that air assist system to environmental qualification.

MR. MICHELSON: When that change was made at that time, did anybody ever go back and look at the 50.59 justification on the change? That's a main steam isolation valve. That's safety-related and all that other good stuff. You can't make a design change of that sort without writing a 50.59 to indicate why it's okay.

MR. LESSER: This occurred during pre-operational testing back in the 1970s when the valve was first found to have --

MR. MICHELSON: You mean they didn't cover -- their design changes during pre-operational testing were not covered by 50.59?

MR. VIRGILIO: The regulation doesn't apply until after they get their license. What typically a facility will do is then start --

MR. MICHELSON: This is pre-operational before; not during startup, but prior to startup.

MR. VIRGILIO: That's correct.

MR. MICHELSON: Okay. Some people start it even then just to get in the habit.

MR. VIRGILIO: That's correct. Just to get into the habit and get the procedures working correctly.

MR. MICHELSON: They're not required.

MR. BENNER: Moving on. At about the same time they were going to implement the mod to upgrade the components to EQ, they got a tech spec change from the NRC saying that they could have a stroke time of eight seconds versus five seconds on these valves. As a result of that, they just decided to eliminate the air assist completely.

From the time they eliminated that air assist to the time this event that we're discussing today occurred, there had been no challenge to the MSIVs at normal operating temperature. So without the air assist, there appears to be no history during operation of the valve's ability to close.

MR. MICHELSON: How many years was this going on that they never had a challenge to those valves?

MR. BENNER: The mod was installed in the spring of 1992, I believe.

MR. MICHELSON: Since then, they've never had a trip on this that required a closure.

MR. LESSER: That's true.

MR. CARROLL: Was that change 50.59'd?

MR. MICHELSON: It should have been.

MR. LESSER: Yes, it was.

MR. CARROLL: What did the safety evaluation say?

MR. LESSER: The licensee determined that the change was acceptable based on the fact that they could remove the air assist and it would be within the new stroke time limits of eight seconds. The valve was tested successfully, stroke tested, after completion of the modification and it passed.

MR. CARROLL: At temperature?

MR. LESSER: At cold temperatures. It was not tested at hot temperatures.

MR. LINDBLAD: Excuse me. But the clearances that we're speaking of are between piece five and piece 15, is that right? Releasing environmental ambient air rather than steam temperature, is that right?

MR. BENNER: The clearance is actually between this and the yoke rods, not necessarily the yoke rods and the plate.

MR. CARROLL: I think the folks from Duke wanted to say something on this.

MR. ABRAHAM: Yes. P.M. Abraham from Duke. I do want to make a comment that during the McGuire Unit 1 1991 loss of off-site power event, the main steam isolation valves were challenged and they did go closed.

MR. CARROLL: Without the air assist.

MR. ABRAHAM: Without the air assist.

MR. CARROLL: Thank you. So it's really a question of just how close the alignment is to cause excess friction.

MR. MICHELSON: This air assist should never have been done to begin with. I thought these had to fail closed on loss of air. Unless they had accumulators and so forth on the --

MR. BENNER: They did have accumulators.

MR. CARROLL: They did.

MR. MICHELSON: They did have that. Okay. Then they could go and do it. All right.

MR. CARROLL: Okay.

MR. LESSER: I think the point is when they removed the air assist, at least two of the four valves on Unit 2 closed completely during the event. As Mr. Abraham mentioned, on the Unit 1 event, all four valves closed. During this event, one valve did not completely close and a second valve was later determined to have essentially leaked excessively.

MR. MICHELSON: It may be different by now.

MR. BENNER: There appeared to be some generic aspects of this probl:m, because the same problem has been found at Sequoyah on the same type valves, and, also, Robinson, which has a different type of MSIV, found that they were also, if they tested at normal operating temperatures experiencing some binding.

As a result of that, Region II is currently drafting an information notice on these issues to get out to the sites.

MR. MICHELSON: Where do you think the binding is?

MR. BENNER: On Robinson?

MR. MICHELSON: Yes. Under McGuire, too. Where do you think the binding was occurring?

MR. CARROLL: On the hose.

MR. BENNER: It's between the yoke rods and the guides.

MR. MICHELSON: That's where you think the binding is, not a shaft binding, not a stem binding at all.

MR. LESSER: Right. Basically, the valve there -- put that back up. The valve there is shown fully closed and what's happening is the yoke -- when the valve is at, say, cold temperatures, the yoke rods are essentially parallel. What's happening is when you heat it up to normal temperature over 500 degrees, the bonnet of the valve expands and you start getting some slight bowing effect of the yoke rods.

What's happening is the valve is not able to fully stroke. In this case, it stroked to about within one to two inches closed.

MR. MICHELSON: Differential temperature distributions cause the bowing, probably.

MR. LESSER: Yes, sir. That's why the vendor recommends to check the clearances while the valve is at full temperature.

MR. MICHELSON: Yes. That's the only time that you can tell.

MR. CARROLL: Okay.

MR. BENNER: Any more questions on MSIVs?

MR. CARROLL: I guess you mentioned some other utilities that looked at this problem. How did that come about? How did they know?

MR. BENNER: I believe Region II took the initiative to canvass the utilities in the region.

MR. CARROLL: But they don't care about what's happening in Region I or V?

MR. LESSER: There is an information notice which has been sent into NRR for distribution to alert the industry of this event.

MR. CHAFFEE: It's in the process of going through that process to be issued.

MR. LINDBLAD: INPO probably did it, too.

MR. GOODWIN: Ed Goodwin, NRR staff. When this event first occurred, we checked in all of the plants -- basically, all the ice condenser plants have the same valve. What we found was Watts Bar not operating, Catawba had taken care of it. D.C. Cook -- I believe McGuire checked with D.C. Cook and they set hot. Then Region II started expanding its effort into similar valves to find out if this problem was unique to the valves that come with the ice condenser, and that's when they tumbled onto Robinson.

So at this point, we think it may be even broader than that in their four ice condensers.

MR. MICHELSON: Those valves don't come with the ice condenser, of course. They just happened to be there.

MR. GOODWIN: Apparently the same valve was supplied with all five ice condenser plants.

[Slide.]

MR. BENNER: Moving on to procedural adherence. The operators performed actions outside of the emergency operating procedures without using appropriate references. This resulted in some I&C personnel jumpering open four closed steam drain valves upstream of the MSIVs, believing that these valves failed open when they, indeed, failed shut.

In the last outage, these valves on this unit had been modified to fail closed. On the other unit, the EOP step states "select closed or gag valve closed," and those valves are fail open. On this unit, the EOP was changed to say "select closed on valves." So even upon a loss of power, if you just do the action that the EOP states, the valves would have been in their safe condition.

Ops believed that these Unit 2 valves failed open and they called for jacking the valve closed, sent some operators out to perform that function. When they got out there, they realized that the jacking screws on the valves had been removed, partially because of the fact that the valves were now changed to fail closed.

At that time, they brought some I&C personnel in to air-jumper the valve closed and, as a result, jumpered the valves open.

MR. MICHELSON: Couldn't they tell by inspection which position the valve was in? I mean visual inspection only.

MR. LESSER: No, they couldn't.

MR. MICHELSON: Why not? There's a solid casing around that --

MS. ENG: Patricia Eng, NRR. I was on the AIT Team. The valve is encased on a metal canister and you cannot tell what the state of the valve is.

MR. MICHELSON: There's no cut slot in the canister to see the position.

MS. ENG: No. There is no indication at all.

MR. MICHELSON: I thought they always had a little cut slot in there and you can always look in and see where the plate is.

MS. ENG: It would have been nice if there had been.

MR. MICHELSON: Yes. Okay.

MR. LINDBLAD: But the EOP did not cover this. These were actions outside of what the --

MR. BENNER: The EOP stated select closed for these valves. Had that been done and that been the only action done, the valves would have been closed, even upon a loss of off-site power, loss of power to the valves.

Also, the reporting procedure --

MR. CARROLL: Am I looking at the right figure here? It appears that there is an orifice bypass around these valves, is that right?

[Slide.]

MR. BENNER: You're talking about these valves.

MR. CARROLL: Yes. And there's an orifice bypass around the drain line. You say they closed them. I'm sorry. I'm okay. Forget it.

[Slide.]

MR. BENNER: Moving on. The licensee's reporting procedure wasn't implemented. As a result, there was a miscommunication between shift and supplemental personnel concerning the reporting of the event, and that resulted in some misinformation getting to the NRC.

The licensee has a green form which they fill out and must submit to the state and counties within 15 minutes of an event. A support clerk telefaxed this green form to the NRC accidentally. At that time, the headquarters operations officer called back to the McGuire control room asking for a little more information.

In that discussion, it was decided that the licensee would call back at the one hour point where they would be required to make the 50.72 report. At that point, the -- subsequent to that, the shift supervisor who was supposed to be on shift with this crew was on vacation. He came in, talked to some people, and the clerk approached him and said that the NRC wanted to have a call and have the green form read to them.

In response to the shift supervisors question has the 50.72 report been made, the clerk responded yes. So he believed he was just going to be providing some supplemental information or clarifying information. He believed the initial report had been made.

When the shift supervisor did, indeed, call, the operations center had the belief that it was the initial 50.72 report. Because the shift supervisor's vision of some of the control panels was blocked, he reported that the SI, the safety injection, was caused by pressurizer heaters being lost. He also responded that all systems had worked as expected and the plant was in stable condition, when, indeed, the B MSIV .d not gone closed and the plant was in a state where it was depressurizing.

That was all I had to say on that.

MR. LINDBLAD: Was there an STA?

MR. LESSER: Yes, there was.

MR. BENNER: Yes.

MR. LINDBLAD: And he was not on the phone, is that right?

MR. BENNER: That is correct.

MR. LESSER: No, sir. That's correct.

MR. LINDBLAD: And that's the way they operate the plant.

MR. LESSER: One of the team's findings was that it was not clearly defined as to who is to make the NRC notification and who is to ensure that the shift supervisor is relieved of duties, EOP reading duties, which he did for the first 15 minutes of the event. Those were some command and control problems that were identified.

MR. CARROLL: I guess I find that very strange that you'd saddle a shift supervisor as a procedure reader. Does Duke have any comments on that?

MR. SHARPE: Robert Sharpe, McGuire. The SROs that are on shift rotate around to different positions during the shift, change of scenery, change of pace. At the time of the event, the shift supervisor happened to be the control room SRO. We do not restrict our SROs as to which role they can be fulfilling at any point in time.

So after the event happened, of course, we moved to relieve him of the procedure reader duties, I believe, by another SRO.

MS. ENG: May I make a clarification? Patricia Eng, NRR. The way that the emergency plan for McGuire is constructed, the person who is given the responsibility of reading the procedure in the event of an emergency is the control room SRO. Due to the assignment of duties that night, the shift supervisor also happened to be the designated control room SRO.

It is my understanding that Duke does not routinely give the shift supervisor collateral duties like this.

MR. CARROLL: I guess I would feel better if I knew that they never gave them that duty.

MR. LINDBLAD: In this rotation of roles, does somebody assume the role of the shift supervisor?

MR. SHARPE: No.

MR. LINDBLAD: So that's a permanent position.

[Slide.]

MR. BENNER: Moving on to document control. As I stated before, the licensee --

MR. CARROLL: Does Duke intend to change that practice?

MR. SHARPE: Yes. We're working on that in preparation for an enforcement conference in about another week.

MR. CARROLL: Okay.

MR. BENNER: These four upstream drain valves had been modified to fail closed on a loss of power due to a containment isolation function. The licensee's program requires that all modifications be reflected in the drawings. Drawings are eventually permanently updated to reflect the modifications.

One of the AIT's findings was that the modification -- the updating of the drawings permanently for this event didn't appear to be timely since the mod was done in August of 1993 and the event was in December of 1993.

MR. CARROLL: How about the issue of factoring this design change into the operator training?

MR. BENNER: In the interim.

MR. LESSER: The operators were trained on this design. They were trained that the valves had been changed from fail open to fail closed. However, the team found that the training was not fully effective, for several reasons. Unit 1 and Unit 2 were different at the time. Unit 1 still had the fail open valves and Unit 2 had the fail closed valves.

When the operators came to the procedure to shut these valves, there was no power to them and there was no light on the control board. So the operators did not fully recollect that the modification had been done, although they had been trained on it, which the AIT verified and initiated actions to change the position of them.

[Slide.]

MR. BENNER: For short-term, prior to the drawings being modified, updated, excuse me, the program dictates that significant changes should be red-marked on the drawings. In this case, all changes weren't clearly identified on the drawing. For this valve modification, the drawings still indicated the valves were fail open, but it did have four modification package numbers stamped onto the drawing.

These modification numbers are located in a file cabinet in the back of the control room and, indeed, had the operators gone through the exercise of pulling out those four modification packages and going through all the changes in them, they would have come to the conclusion that the valves were fail closed. But it seemed somewhat unreasonable that in the heated battle of an event that you would actually do something like that.

MR. CARROLL: In his spare time, while he was reading procedures, the shift supervisor probably should have done that.

MR. BENNER: Right. The shift supervisor could have had two documents going. The program has no guidance as to what constitutes a significant change. That seems to be where a lot of latitude takes place as to what needs to be changed on the drawings so that is self-evident and what doesn't.

The decision as to what is significant change is made by an operations modification coordinator.

MR. LINDBLAD: Is that a licensed operator?

MR. LESSER: Robert Sharpe, could you answer that?

MR. SHARPE: I don't know right offhand.

MS. ENG: It's my recollection that the operations modification coordinator is a clerk that does not receive any operator license training.

MR. LINDBLAD: Thank you.

[Slide.]

MR. BENNER: Next, I wish to discuss some issues on the corrective actions from the 1991 event. On the 1991 event, I will just briefly summarize it. There was some post-maintenance testing going on on the auto transformer between the 230 and 525 kilovolt switchyards.

Defective relay caused the loss of the 1A bus line by opening one of the breakers. Full current being passed through one of the outgoing lines resulted in the 1B line tripping in .2 seconds. For that event, it was determined that contributors to the cool-down, as I had said previously, for that event, there also was a cool-down, depressurization and resultant safety injection.

It was believed that Valve 1SM-15, which is a 14-inch steam supply to the moisture separator reheaters, fails open. It is somewhat misleading because downstream of that valve there are large valves that go closed, but there are a bunch of drain valves that come off that line.

MR. MICHELSON: Why did it fail?

MR. BENNER: What?

MR. MICHELSON: Why did it fail?

MR. BENNER: It did not fail. It's designed to go open.

MR. MICHELSON: I thought you said it failed open. So it failed in the right direction.

MR. BENNER: It failed as it was designed to fail.

MR. MICHELSON: The designed direction at least. Was that a --

MR. BENNER: Upon a loss of off-site power, the valve goes open.

MR. MICHELSON: Why does that normally go open on loss of air or power or whatever?

MR. LESSER: Maybe the licensee can answer that.

MR. MICHELSON: Beg your pardon?

MR. LESSER: Maybe the licensee can answer that question.

MR. MICHELSON: Why is that designed to fail open?

MR. SHARPE: I think most of these valve positions for failure of valves on the secondary side are pretty much standard industry practice for protection of the turbine and getting condensate out of the steam lines in case of a trip.

MR. MICHELSON: You're talking now about this 14-inch valve 2SM-15.

MR. SHARPE: Right. Yes.

MR. MICHELSON: That's the steam supply to the moisture separator reheaters. Why would it be wanting to be kept open?

MR. SHARPE: I don't know specifically for that valve, but --

MR. MICHELSON: I'm a little puzzled, but that's all right.

MR. BENNER: For this recent event, there were several contributors to the cool-down. One was basically the mirror valve on Unit 2 relative to the valve on Unit 1. In addition, there were several drain lines that failed open. As I had stated before, aux feedwater flow had not been throttled. It was injecting at approximately 400 percent of what you need to provide cooling.

After the 1991 event, the licensee implemented a step to close the MSIVs in the event of a rapid depressurization. The licensee's memo to the operators claimed that that step could be reached within two minutes from initiation of an event.

For this event, the safety injection occurred at seven minutes into the event and the step I believe was the next step that was about to be completed.

MR. MICHELSON: Was there a reason for seven minutes, why it took that long?

MR. BENNER: One of the reasons, I believe, is the EOP that McGuire uses has a fold-out page at the beginning of the EOP for which there are some items that you should be continually monitoring. That gives the licensees freedom to be able to trigger out of that procedure into a different procedure if a different procedure is more appropriate.

An AIT finding, as well as one of the licensee's own audit findings, is that there seems to be more time than necessary being spent reviewing continual action steps on that foldout page, which may have contributed to the delay in getting to the step to close the MSIVs.

[Slide.]

MR. BENNER: At McGuire, it appears that unless further actions are taken, you could reasonably expect that any time you get a loss of off-site power, you're also going to get a safety injection.

At this point, the relative contributions of the cool-down from steam loads and the non-throttling of aux feedwater flow are being determined. I believe the licensee is committed to getting us their plan of action by April 1.

This last bullet is somewhat administrative. As shown by these two events, the one on Unit 1 in 1991 and the one on Unit 2 in 1993, the actual design of the plant is that on a loss of off-site power, you're going to get a reactor coolant system cool-down and resultant depressurization. In both events, you've also got a safety injection.

A safety injection following a loss of off-site power was not included in the licensee's final safety analysis report. Whereas this may not necessarily be a problem, Reactor Systems Branch has made the comment that it does provide a complication to what would be expected to be a fairly simple transient.

In addition, the licensee's FSAR and their individual plant examination indicate that a LOOP, a loss of off-site power, will result in an RCS heat-up and resultant pressurization, which is why an SI was not assumed. The assumption is that you would have relief valves or safeties lifting to mitigate pressure.

Any questions on corrective actions?

[No response.]

MR. CARROLL: Go ahead.

[Slide.]

MR. BENNER: The last issue wasn't really an issue. It was just an initiative taken by the Risk Assessment Branch of NRR to perform a risk assessment on this event. The preliminary staff analysis of the event estimates that there was a conditional core damage probability of two-times-ten-to-the-minus-four.

The breakdown of that is that standard loss of off-site power sequences account for 1.1-times-ten-to-the-minus-fourth of that total.

MR. DAVIS: Excuse me. I'm a little confused. You had a loss of off-site power --

MR. BENNER: Right.

MR. DAVIS: -- as part of this event. I had assumed that the conditional part of the probability was given the loss of off-site power.

MR. BENNER: That is true and that's what the phrase "conditional core damage probability" is standing for.

MR. DAVIS: Right.

MR. BENNER: On the condition that you had the loss of off-site power.

MR. DAVIS: Right. How can a loss of off-site power sequence account for part of the total when that was the conditional event.

MR. BENNER: This is not saying -- this is saying that loss of off-site power sequences are you have your loss of off-site power and then you have subsequent failures of equipment that get you to a core damage state.

That's what that statement is referring to. After you've got the loss of off-site power, what is the probability that you're going to get enough equipment failures such that you'll get core damage.

MR. LEWIS: When it says LOOP sequences account for that fraction of total CCDP, does it mean CCDP?

MS. ROSENBERG: Yes.

MR. BENNER: Yes.

MR. LEWIS: The C means conditional on the loss of off-site power.

MR. BENNER: Right.

MR. LEWIS: So loss of off-site power accounts for ten-to-the-minus-four of the total condition of loss of off-site power. I don't understand that logic.

MS. ROSENBERG: Stacy Rosenberg, NRR. It's just a breakdown of the conditional core damage probability.

MR. BENNER: If you will notice, these two pretty much add up to that.

MR. DAVIS: Hal, I think what they mean is that the first one is --

MR. BENNER: It will be more clear when I get to the second one.

MR. DAVIS: Given no other failures except a loss of off-site power, like steam generator tube ruptures, that would be the contribution.

MS. ROSENBERG: That's correct.

MR. BENNER: Let me just get into the second bullet for a second. Standard IPEs don't model a transient-induced steam generator tube rupture. For standard IPE, these numbers would be the same. For this event, since we had the 1981 psi delta P across the steam generator tubes, the PRA Branch took it upon themselves to model a transient-induced steam generator tube rupture, because we're in a situation where if you have a loss of off-site power at -- during this event, you had the loss of off-site power and you had a resultant large delta P across the tubes.

So in a standard modeling of a loss of off-site power, you would not even take this into account. But since we had a specific failure of an MSIV which caused the steam generator to go dry, this was something that we felt was important to model. Does that make it clearer?

MR. LEWIS: Not to me.

MR. DAVIS: It would be real helpful to have an event tree when you show these and then you can follow it.

MR. LEWIS: It doesn't make it clear to me. Forgive me for being stupid. It's just a triviality. Conditional cause of core damage frequency is conditioned on the loss of off-site power.

MR. BENNER: On the loss of off-site power.

MR. LEWIS: That means that if I want to know the actual loss to the core damage probability, I hate the word "frequency" for "probability," but that's another matter.

If I wanted to know the actual core damage probability, I should take that number and multiply it by the probability of a LOOP, right?

MR. BENNER: Right.

MR. DAVIS: Right.

MR. BENNER: Right. That's why I say for standard modeling, these two numbers are the same.

MR. LEWIS: My problem is only on the first thing that has a dash, where it says LOOP sequences.

MR. BENNER: Right.

MR. LEWIS: When it says LOOP sequences --

MR. BENNER: Maybe I should have put standard modeled LOOP sequences.

MR. LEWIS: But I don't understand -- I'm just being very dull. I don't understand how a LOOP sequence is part of a LOOP.

MR. DAVIS: That bullet shouldn't even be there.

MR. LEWIS: Do you understand what I don't understand?

MR. DAVIS: I've got it now.

MS. ROSENBERG: In the accident sequence precursor model, there is a loss of off-site power event tree. What I'm trying to do is show you the breakdown. If you're losing a loss of off-site power event tree for McGuire and given that you have a loss of off-site power, the conditional core damage probability is 1.1-times-ten-to-the-minus-four, without any other failures.

MR. LEWIS: I understand that. I understand that. These are all the sequences, the whole part of the tree that begins with the loss of off-site power.

MS. ROSENBERG: That's right.

MR. LEWIS: I understand all that. What I don't understand is what fraction of that part of the tree that first dash is, because the first dash says it starts with loss of off-site power and I thought the whole tree we're talking about starts with loss of off-site power.

MS. ROSENBERG: That's --

MR. BENNER: That's true, but most times, when you model it, you don't have this portion.

MR. LEWIS: I'm talking about the one above that.

MR. BENNER: I understand that.

MS. ROSENBERG: Because you have to go further with the loss of off --

MR. BENNER: We're adding a branch to the fault tree.

MR. CARROLL: So the 2-E-minus-four would really be 1.1, if it weren't for the --

MR. BENNER: If we did not model the additional transient-induced steam generator tube rupture, which isn't standard modeled because you don't -- it hasn't been assumed that you would -- that transient-induced steam generator tube ruptures are credible.

MR. DAVIS: You might include it would be a very low probability normally.

MR. BENNER: Right.

MR. DAVIS: But in this event, it became much higher because of what happened. I think the slide would be good if you didn't even have that first bullet up there, because that's sort of a given. It would eliminate all the confusion.

MR. CATTON: Just put another branch on the tree.

MR. DAVIS: Yes. Put another branch on the tree.

MS. ROSENBERG: It's just showing where the contribution is coming from.

MR. LEWIS: Both begin with a loss of off-site power.

MR. DAVIS: That's right, yes.

MR. LEWIS: One goes through a steam generator tube rupture and the other doesn't.

MR. DAVIS: Right.

MS. ROSENBERG: Yes, because the loss of off-site power induced --

MR. LEWIS: Okay. You're telling me that that first thing, which says LOOP sequences, should say LOOP sequences except for the ones that include steam generator rupture.

MS. ROSENBERG: Yes.

MR. LEWIS: If you had said that, we wouldn't have had this debate.

MR. SEALE: That's the no leg.

MR. LEWIS: So other LOOP sequences.

MR. SEALE: Yes.

MR. LEWIS: That word would have helped a great deal.

MR. DAVIS: An event tree would help even more.

MR. KRESS: Now that we've cleared this up, let's -- we're running a little behind.

MR. LEWIS: So it's really mislabeled. Okay.

MR. CARROLL: We can read the NRC actions.

MR. BENNER: I believe I have, for the most part, covered all of them as I went through the issues. That was just a summary bullet.

MR. CARROLL: Okay. Any other questions?

[No response.]

MR. CARROLL: All right. Again, we'd like to thank the staff. This, too, was a very good presentation. I guess we didn't give Duke an opportunity to say anything they might want to add to this. It sounds like they've had enough troubles already.

MR. SHARPE: Yes. Thank you for the opportunity but we're preparing our enforcement conference presentation and a number of these issues we may have a slightly different slant on. Rather than getting into an enforcement conference discussion here --

MR. CARROLL: This is not the time or place.

MR. SHARPE: Yes.

MR. DAVIS: Is the plant back up now?

MR. SHARPE: Yes.

MR. LINDBLAD: Thank you for coming to help us today.

MR. CARROLL: Should we blame Charlie for all of this? We thank Duke for coming, also. You made a contribution.

MR. SHARPE: Thank you.

MR. CARROLL: It looks to me like we could either -- we're 15 minutes behind. We could break for lunch and pick the letters up.

MR. WILKINS: I would propose that we break for lunch, return from lunch at 1:00 and we'll get through this reconciliation. I think we can do that fairly quickly. That's the item that was supposed to have been done at 11:45 today.

We have not recessed, gentlemen. Mr. Lindblad.

MR. LINDBLAD: Can I remind the members that Mr. Bagchi will give a little presentation on North Ridge earthquake effects in Room 422 during the lunch break?

MR. KRESS: Starting when?

MR. LINDBLAD: In ten minutes.

MR. WILKINS: I also have a note that says Med has provided cakes for the staff and members available in P-412. That's an awfully tough choice to make.

MR. LINDBLAD: I guess Mr. Bagchi is up there munching already.

MR. WILKINS: Munching on our cakes, yes. We will reconvene at 1:00.

[Whereupon, at 12:06 p.m., the Committee was recessed, to reconvene this same day at 1:00 p.m.]

AFTERNOON SESSION

[3:02 p.m.]

MR. WILKINS: Let's reconvene.

The next agenda item is the discussion of revisions to the LLNL Probablistic Seismic Hazard Methodology for the Eastern United States.

The subcommittee chairman, Bill Lindblad, I turn the meeting over to him.

MR. LINDBLAD: Thank you, Mr. Chairman.

This is Item Number 14 in your binder, and there is a loose-leaf Item 14 which was added to it today for your information. We have not had a previous subcommittee meeting on this presentation, so this is going to be new for all of us, but it involves recent work done in NRR regarding Eastern United States seismicity, and we are going to have the presentation by NRR describing this activity. We expect that following the NRR presentation that NUMARC and perhaps other industry representatives will have some comments to make about it.

Opening the presentation will be Mr. B.D. Liaw.

MR. LIAW: Thank you, Bill.

My name is B.D. Liaw. I am the Deputy Director, Division of Engineering in NRR. We are happy to be here today to brief the committee on the results of the latest seismic hazards study done by our contract at Lawrence

Livermore Laboratory.

As you all know, since after the 1989 study, the first study, EPRI also conducted their own study which shows the substantial differences in order to reconcile the differences and also to find out why those big differences were created, the NRR staff undertook the task, again done by Livermore, to do this study and we are here to present to you the results of that. Representing the staff to make the presentation will be Dr. Phyllis Sobel. She was the program manager for that work.

Phyllis.

MR. LEWIS: While they are getting ready, I am always a little bit confused. There surely isn't then a belief any where that if you ask more experts to divide by the square root of N you get a better estimate of the correct answer. That is certainly not anyone's solution, is it?

MR. KRESS: That is what they did in 1150.

MR. LEWIS: I see it happening, you know. The more people agree, the more people think that that must be the true answer, but there is no evidence that that is the case.

MR. LIAW: No. Dr. Lewis, that is not the case, I hope. I think it involves more than that. It went into the basic methodology of how this expert opinion was put together, or synthesized, in a sense.

MR. LEWIS: It is the put together that troubles me a little bit because the expert opinion world is in some sense a real measure of the uncertainty.

MR. LIAW: And how to deal with those uncertainties.

MR. LEWIS: Well, it is always hard to deal with uncertainties.

MR. LIAW: And that will be one of these things --

MR. LEWIS: I was only trying to kill time while she was getting ready.

MR. CATTON: You succeeded.

MR. LINDBLAD: Of course, this committee of eleven wondered whether you were going to say only one of us could do the work of the ACRS.

MR. LEWIS: Better.

MR. LINDBLAD: Dr. Sobel, would you begin?

[Slide.]

MS. SOBEL: I am going to present the updated Livermore probablistic seismic hazard estimates for the nuclear power plant sites in the Eastern United States. As Dr. Liaw was mentioning, Livermore has been involved with NRC in probablistic seismic hazard analysis since the 1970s, and this particular study that was executed in 1992 and 1993 is an update of work that was published in 1989.

At about the same time that Livermore was undertaking their probablistic seismic hazard analysis, EPRI developed their own seismic hazard analysis methodology, and you have probably seen the comparisons of the two before, but I will give you an example.

[Slide.]

MS. SOBEL: This plot shows the probability of exceedence versus peak ground acceleration, and on illustrated the 15th, 50th, and 85th percentile curves for both the EPRI and the Livermore study. You can see that both the EPRI and Livermore medians, 50th percentiles, are fairly close, but that the measure of uncertainty, the difference between the 85th and 50th percentile is larger for Livermore.

MR. WILKINS: Yes.

MR. LINDBLAD: Dr. Sobel, I hate to interrupt you so soon, but, of course, when we speak of experts and opinion, we are really not speaking of the two contract managers called Livermore and EPRI, are we?

MS. SOBEL: That's right. Right. The Livermore methodology includes input from seismicity and ground motion experts. I will explain their approach.

MR. LINDBLAD: Not necessarily working for the laboratories?

MS. SOBEL: They are under subcontract to the laboratories.

MR. LINDBLAD: But they are independent external experts?

MS. SOBEL: That's right, they are independent experts.

MR. LEWIS: In fact, it is important to say that. The word "methodology" really means methods for assessing the opinions of experts.

MS. SOBEL: That's right, and it includes the elicitation.

MR. LEWIS: Yes, it is not a technical methodology.

MS. SOBEL: It includes the elicitation of expert opinion and the computer code used to estimate seismic hazard.

MR. LEWIS: The code is irrelevant. The point is that the numbers which are given, the numbers that finally appear here are the opinions of experts based on their knowledge of the geology, and of the history, and that sort of thing. It isn't as if people are making 30,000 measurements, and finding the 50 percent.

MS. SOBEL: That's right.

MR. DAVIS: Dr. Sobel, I haven't looked at these curves for a while, but it is my recollection the last time that I used them for anything their agreement was considerably worse than this Limerick result, and I am wondering why you picked this particular one. It seems like most of the disagreement was considerably greater than this for the median; is that not correct?

MS. SOBEL: The medians were really basically similar.

MR. DAVIS: I meant the means.

MS. SOBEL: The mean, okay. The mean I haven't shown here. I just showed the 85th percentile.

MR. DAVIS: I am sorry.

MS. SOBEL: But it does vary from site to site.

MR. WILKINS: To follow up on that, though, is Limerick in some sense typical or is it your position that there really isn't a typical site and each one has to be looked at separately?

MS. SOBEL: That's right, each one is different.

MR. LEWIS: If one were to read these curves just raw, the first time I have ever seen them, I would say, gee these two groups agree, but one is a little more cock-sure than the other. Is that the way to read these curves?

MS. SOBEL: You could read it that way, yes. In fact, it was --

MR. WILKINS: Dr. Sobel, you will get along much better with this committee if you ignore most of the noise level and keep on going.

MR. LEWIS: But, Ernest, our job is the elicitation of expert opinion.

MR. WILKINS: Yes, but you see that is not noise. But occasionally there is some noise around the table. Just keep going.

MS. SOBEL: Okay. Since these Livermore results were published, Livermore applied their methodology at DOE sites, especially the Savannah River site, and as a result of that investigation it was determined that changes could be made in the methodology to better characterize the elicitation of uncertainty from the seismicity and ground motion experts.

[Slide.]

MS. SOBEL: It was based on that work that we did this update in 1992 to 1993. Just very briefly, the Livermore methodology is a Monte Carlo simulation approach. You take experts from the fields of seismicity and ground motion. The seismicity experts gave Livermore maps of seismic source zones, and within each source zone the rate of earthquake occurrence. The ground motion experts each gave Livermore ground motion models. Then these expert's inputs were put into a computer code where over and over many thousands of times simulations were made for hazard estimates a particular site, and it is from that collection of thousands of simulations that we finally derived the percentiles you saw in the last figure.

[Slide.]

MS. SOBEL: This next figure is an example of source zone map. We did not reelicit source zone information from the experts in this study because we didn't feel that that was going to make a change in the uncertainties. So I show this figure mostly to make the point that this is a regional study. This was never an attempt to develop site-specific probablistic seismic hazard estimates around each site. You can see from the way the source zones are drawn, and each map is very different, believe me.

MR. WILKINS: Forgive me, this looks like a map drawn by a politician designed to ensure his reelection. Is there some rationale to these zones?

MS. SOBEL: They are generally based on seismicity and geologic history.

MR. WILKINS: These are not -- what did he call these, iso-something-or-another lines?

MS. SOBEL: They are not based on any ground motion estimates, no. They are based on geologic history and recorded historical and instrumental seismicity.

[Slide.]

MS. SOBEL: Now I am going to explain what is one of the key differences between the 1980s and the 1990s

Livermore studies. As I said, each seismicity expert develops at least one map of source zones for these Eastern United States, and then for each of those source zones the expert gives Livermore the rate of earthquake occurrence. This is a fairly common line known to seismologists as the Gutenberg-Richter relationship, you take the log of the rate of earthquakes and it is equal to the Y intercept or A value minus the slope or the B value times magnitude.

In the 1980s, the experts were asked to give an A value and a B value for each source zone, and then an uncertainty associated with the A values and the B values and, as you can imagine, as you get into the larger magnitudes, there is much more uncertainty then.

In fact, in this figure the center line might be the median estimate and the upper and lower line might be the 95th and 5th percentiles, and you can see that it is possible in picking simulations you might sample something from the higher end at larger magnitudes that could be unrealistic.

MR. LEWIS: Isn't there an additional problem because the straight line on a semi-log plot, I guess it is really a log-log plot is empirical anyway, and the empiricism is pretty good because most earthquakes between, say, four and seven, though there are very few sevens, are actually observed, but once you get below four, the threes are not. There is a lot of missing data which show up as a curvature in the observed rate, and people are fitting to the higher and then extrapolating to the lower. So when you speak of the intercept, which is at the very low end, you are speaking of an area that is not well sampled by the empirical data. So fitting it to a straight line is a fudge.

MS. SOBEL: Right.

MR. WILKINS: But she can certainly fit the data between three and seven to a straight line. Having done so, she can interpret. She can say that A is the intercept, but it doesn't have any meaning with respect to seismic events.

MR. LEWIS: Except the 3-4.

MR. BAGCHI: Dr. Lewis, for our study, three and four are of no consequence. They are so small we don't worry about those.

MR. LINDBLAD: Yes, but, Dr. Sobel, is this not really a model and that, in some cases, there is no data to fill in the blanks; is that right?

MS. SOBEL: Right. I think the next figure can actually illustrate that point.

MR. BAGCHI: That is the cartoon-style picture.

MR. CATTON: But the shape of the curve could impact the other end as well, and I think that is the point.

MR. LEWIS: That is the point I was trying to make.

[Slide.]

MS. SOBEL: This is the point we can make with this particular figure, too. Thank you for explain it.

This is an actual figure used in an elicitation. For each of the interviews Livermore gave the seismicity experts the information that they had developed in the 1980 study, and the actual data for that particular source zone. So the circles on this diagram represent the actual data and you can, in fact, see that at the lower magnitudes it does look close to a straight line, but this is where we have a lot of instrumental seismicity information from the last 20 to 30 years.

As we get into the larger magnitudes, we have to rely on the historic record in the Eastern United States, which is only several hundred years long, so we may not be sampling all the larger earthquakes at the higher end, and that is why you see the historical and instrumental data look like a straight line at the lower magnitudes, but tends to decrease at higher magnitudes.

Now on this figure beside the circles Livermore has also drawn on for the experts the information that they provided in the 1980 study. So the center line on the figure would be the expert's best estimate for that zone from the 1980s, and then based on the A and B values that the experts gave Livermore and the uncertainties associated with them, the upper and lower lines are the 95th and the 5th percentiles from the 1980 study.

Now this is where we have adopted a change in methodology. Instead of asking for the Y intercept and the slope and the uncertainties associated with them, instead Livermore now asked the experts to determine the rate of earthquake occurrence at two different magnitudes to give the best estimate and the uncertainty at just those two magnitudes.

On your figure in front of you, you see a little horizontal line, those are the actual lines the experts drew into the figures. I put them in red on the viewgraphs so that you can see them better, and you can see the center red mark which is the best estimate, or in this study it was used as the 50th percentile, is close to the data points. The 5th percentiles that were chosen by the experts in 1992 were higher than the 5th percentile from the 1980s, and similarly there was less uncertainty in choosing the 85th percentile.

This had a dramatic effect on the hazard estimate because in every case you saw less uncertainty in the seismicity inputs.

MR. WILKINS: It is an order of magnitude.

[Slide.]

MS. SOBEL: For ground motion, Livermore convened a workshop with experts on expert elicitation. These people come from a variety of background, but are considered to be experts in the process of expert elicitation, and they considered the type of information that is collected in probablistic seismic hazard studies. Actually they considered both the seismicity and the ground motion information. Livermore was looking for some inputs to help them understand the best way to elicit the ground motion information because, frankly, we weren't sure in the 1980s all the experts understood the uncertainty estimates that they were giving with the same precision.

One of the recommendations was that the experts be interviewed individually instead of just given a questionnaire. Also it was suggested that there be a workshop first so that the experts can disseminate their ground motion information and understand the differences between the various models that they had used in the 1980s.

[Slide.]

MS. SOBEL: Actually the next figure explains the differences a little better.

MR. WILKINS: That is the answer to my question.

MS. SOBEL: The key difference in the elicitation is that instead of having ground motion experts give Livermore models, equations that said acceleration is some function of magnitude and distance to the site, instead this time the experts were asked to estimate ground motion at certain magnitude and distance, distances from the site.

For example, what would the expert think is the best estimate of peak ground acceleration at 25 kilometers from a magnitude six earthquake. Then the expert was asked, what uncertainty would you associate with that. This was an attempt to force the experts to look at their hazard estimates for particular magnitudes and distances to see if they were aware of the consequences of the uncertainty numbers.

MR. LEWIS: Let me be sure I understand what you just said. They were asked to estimate the uncertainty in their estimate of the ground motion at a given distance from a known magnitude, is that what was done?

MS. SOBEL: That's right.

MR. LEWIS: When they were asked to estimate the uncertainty, were they given any hint about whether they should, in estimating the uncertainty, take a standard deviation or an outer limit, or what were they told to do?

MS. SOBEL: I believe they picked one standard deviation generally.

MR. LEWIS: Standard deviation, so there was an assumption that their estimate added or their mental picture would be a Gaucian distribution or a normal distribution, and they were defining the -- the reason I am asking this is that I have known lots of seismic experts, and they may know a lot about rocks, but generally they don't know much about statistics. So when you ask them for an uncertainty, they may have wildly different understandings of what they are being asked.

MS. SOBEL: That's right. The Livermore author of the report, Jean Savy, is here. I wonder if he would like to address that.

MR. LEWIS: Okay. Let me not slow you down. Since I have distracted you let me ask one other question, at what stage in the game does any expert learn what the other experts have said, does that happen only after it is all over and published, or does it happen half way through?

MS. SOBEL: There is feedback between Livermore and EPRI after the first elicitation, but I would say that the experts don't know what the others have done until the entire study is completed.

MR. WILKINS: So it is not in any sense a Delphi procedure?

MR. LEWIS: That is what I am trying to find out.

MR. WILKINS: Yes.

MR. ROTHMAN: This is Bob Rothman.

I attended the ground motion workshop, and it was a two-day workshop in which each expert was questioned by people from Livermore, and then the following day the results were presented back to them so that they could see their results and the other people's results, and some experts said, you misunderstood what I said, that is not what I meant to say, and they actually changed their results after the feedback.

MR. LEWIS: So there was a Delphic element to the elicitation.

MR. ROTHMAN: There was a feedback.

MR. LEWIS: And that contains well-known traps, which everyone knows.

MR. ROTHMAN: I don't know. I am just telling you what I saw.

MR. LEWIS: That is very useful and very helpful. As long as there is a Delphic element, many of us know the traps.

MR. CARROLL: You were going to answer his first question?

MR. SAVY: I think Bob Rothman answered that.

MR. LINDBLAD: I think I would like to have Dr. Sobel maintain her momentum on this, and we will get to those in a minute or so.

MR. WILKINS: May I ask one question about this slide?

MS. SOBEL: Certainly.

MR. WILKINS: Were the five ground motion experts in the '80s a subset of the seven in '92 or not?

MS. SOBEL: Of the five ground motion experts that were used in the 1980s studies, one was dropped because he was not longer active in the field, and we decided to pick up several other ground motion experts.

MR. WILKINS: But four of them survived?

MS. SOBEL: Yes, four of the five survived.

MR. WILKINS: And then there were three extras, three additions.

MS. SOBEL: Then three were added, yes.

MR. WILKINS: Thank you.

MR. LINDBLAD: Were all the ground motion experts exclusive to this or were some of them also in the seismicity panel?

MS. SOBEL: I believe there may have been one that overlapped.

[Slide.]

MS. SOBEL: I am going to go right to the results because I think I can use that to make some of these points. This figure is taken from the NUREG 1488. Livermore produced a rather thick final report which we put in the public document room, but to make the report's information more easily available to more people, the staff produced a NUREG and very briefly summarized Livermore's report. There are tables in the NUREG of the Livermore hazard estimates. There is even a table of safe shutdown earthquake values, if you want to compare seismic design to these numbers.

That report, by the way, was available for public comment. To date I have received only two comments. The public comment period ended February 28th. Neither comment addressed the technical aspects.

MR. LINDBLAD: I am sorry, what technical aspect, the elicitation or the --

MS. SOBEL: The technical aspects of the Livermore report. The thrust of both technical comments had to do with the IPEEE program, in other words the use of this data.

MR. LINDBLAD: I see.

MR. LEWIS: Is this really mean acceleration and not median?

MS. SOBEL: This is mean.

MR. LEWIS: And the probability is also a mean or median?

MS. SOBEL: Mean.

MR. LEWIS: Both on the horizontal and the vertical axis we are talking about mean?

MS. SOBEL: Yes.

MR. WILKINS: Let me rephrase his question, the ordinate is the probability that the mean acceleration will exceed the abcisa?

MS. SOBEL: That's right.

MR. LINDBLAD: Are you saying it does not have a distribution?

MR. LEWIS: That is what I am trying to understand because Limerick stuff we saw did have a distribution estimate and there the central thing was the median, and when you have wide distributions like these things, there is a big difference between the mean and the median and I need to know which I am looking at.

MR. LINDBLAD: The distribution is on the acceleration, not on the probability.

MR. LEWIS: No. There was a distribution on the probability also, as I recall.

MS. SOBEL: Yes.

MR. LEWIS: Because there were 15th percentiles.

MR. WILKINS: This is the probability of exceeding the mean. The probability that the observed mean is going to exceed the -- that the sample mean will exceed the mean that is recorded as the abcisa.

MS. SOBEL: This is the mean probability of exceeding the peak ground acceleration values shown on the X axis.

MR. LEWIS: There is a distribution of the probability?

MS. SOBEL: Yes.

MR. WILKINS: What she said was not what I said, so I need to stand corrected in that regard.

MR. LEWIS: We will see. Please go on.

MS. SOBEL: The purpose of this figure is to compare the 1980s Livermore hazard estimate which, in this figure, is the top curve, the 1980s EPRI estimate, which is the lower curve, and the one in the middle which is 1993 or 1992 Livermore hazard estimate. As you can see, there has been a substantial reduction in the mean between the 1980s and the 1992 study.

In fact, the EPRI and the 1992 Livermore hazard curve are fairly close at these low peak accelerations. Now this site Pilgrim is in the Northeastern United States in an area where we have a larger record, relatively larger record of historical seismicity, and also a slightly higher level than other areas in the Eastern U.S., so you would expect that the two studies would be able to model peak acceleration much more closely at this site at the low peak accelerations, but you will notice that at the higher peak accelerations the two studies differ.

Pilgrim is a soil site and we noticed that one of the situations where the EPRI and Livermore hazard curves still differ is at soil sites. Of course, this area, which is larger than the safe shutdown earthquake level, is where you would find potential impact in probablistic risk assessment studies.

[Slide.]

MS. SOBEL: The other area where we noticed there were still significant differences between the 1992 Livermore and the EPRI hazard estimates was at low seismicity sites. This is the Shearon Harris site which is in Central North Carolina, an area of relatively low seismicity, and you can see even though there has been a substantial reduction in the Livermore hazard estimates from 1989 to 1992, there is still a difference between the Livermore and the EPRI hazard estimates.

We have been looking at peak ground accelerations, but I am going to switch to looking at spectral estimates.

[Slide.]

MS. SOBEL: In this case, this is the Seabrook site which is in New England, and if you squint I think you can see the dash curves are the 1980s Livermore curves, the 85th, the 50th and 15th percentiles, and the solid curves are the 1993 Livermore estimates for the 85th, the 50th and the 15th percentiles.

[Slide.]

MS. SOBEL: I am going to show you and compare the results of three different sites. The first site is the River Bend site, which is in an area of low seismicity in Louisiana, and for the viewgraph I have colored in the SSE as blue. This is a low seismicity site. The three curves below the SSE are from the top the 10,000 year, then the 5,000 and 2,000, and 1,000 spectra. These are spectra that have the same probability of exceedence across their frequency range, and you can see that the SSE spectra falls above the largest one here, the 10,000 year spectra, which is something you would expect because this is an area of relatively low seismicity. Now River Bend is a deep soil site.

The next one I am going to show, Oconee, is a rock site.

[Slide.]

MS. SOBEL: You can see that the spectra are different shapes, the shape of the spectra depends on the site conditions. Also, if you notice, both River Bend and Oconee have the same peak ground acceleration for the SSE, but River Bend is a Reg Guide 1.60 spectral shape, and Oconee is a Housner spectral shape, so this shows you the difference between an older and a new spectral shape for seismic design.

In the case of Oconee, which is in an area of higher seismicity than River Bend. The uniform hazard spectra for the 1,000, 2,000, 5,000 and 10,000 year spectra overlap the safe shutdown earthquake, and at a frequency of 1 hertz, the uniform hazard curve closest to the spectrum is a 10,000 year spectrum. At the higher frequencies, the closest curve is the 1,000 year spectrum, and this is typical of what you would expect based on what we know from Eastern U.S. seismicity that the frequency is going to -- sorry, the probability of exceedence will change with frequency of the safe shutdown earthquake.

[Slide.]

MS. SOBEL: The last example is from Seabrook. Seabrook is a rock site like Oconee in the Northeastern United States. In this case, the safe shutdown earthquake for Seabrook is fairly high for an Eastern U.S. site, it is .25g, Reg Guide 1.60. The hazard curves are slightly higher than at the Oconee site, but here the spectrum is much more conservative.

MR. LEWIS: Just to understand the numbers, these are at a site and, therefore, they include contributions from both small earthquakes nearby and large earthquakes at large distances all put together into an acceleration; is that correct?

MS. SOBEL: That's right.

MR. LEWIS: So in some cases we are talking near motion and in some cases far motion, so in some cases we are talking Rayleigh waves, in other cases we are talking Love waves, is that the kind of thing?

MS. SOBEL: No, these are strong ground motions, and actually most of the contributions come from within about 25 kilometers of the site. That is your primary contribution.

MR. LEWIS: So mostly Rayleigh and Love waves and that kind of thing, probably, put together.

MS. SOBEL: He is saying sheer waves, but these are strong ground motions.

[Slide.]

MS. SOBEL: This figure suggest several of the uses for these probablistic seismic hazard curves. We are reconsidering the approach that was used in the IPEEE plant binning, and we may be doing a reanalysis of that binning. Of course, these curves could be used in probablistic risk assessments and in any safety evaluation reports for any future sites.

Do you have any questions?

MR. LINDBLAD: Yes. As I understand, you consider this new study to have replaced the earlier study; is that right?

MS. SOBEL: Yes. We found the experts. We are more comfortable with their inputs, and we still have a number of sensitivity studies that we plan in the next year because we have only discovered -- we have only analyzed five or six sites, so we would like to do more sensitivity studies. We know that updating the seismicity parameters has decreased the seismic hazard at a peak ground acceleration of .2g by about a factor of five.

MR. LINDBLAD: And as I understand, neither of your public comments cast any suspicion on the credibility of the results; is that right?

MS. SOBEL: One public comment agreed with us that we needed more sensitivity studies.

MR. LINDBLAD: But there is an engineering geologist in the Army engineers who does not feel very strongly about your method, is that right?

MS. SOBEL: Yes.

MR. LINDBLAD: Can you comment on what Dr. Krinitsky has said?

MS. SOBEL: I wasn't prepared to talk about Dr. Krinitsky's comments. He is one of those who is not in favor of using probablistic seismic hazard analysis because he believes it is only as good as the experts who are providing the input.

MR. LINDBLAD: I would observe that he is an engineering geologist, and he observes that you had very few geologists in your seismicity panel.

MS. SOBEL: Some of the experts had a geological background.

MR. LINDBLAD: Thank you.

MR. SEALE: Could I ask, among the experts in the second most recent study was the individual sometimes identified as Expert Number 5, was he also in that group?

MS. SOBEL: Definitely, yes. He was included in the second set.

MR. SEALE: Okay, I was just curious.

MR. DAVIS: I understand that there is still another effort going on sponsored by Research to try to reconcile these curves.

MS. SOBEL: There is an effort funded by Research, EPRI, and DOE which in its inception talked about reconciling these curves but is now more interested in determining a procedure for probablistic seismic hazard analysis in the future.

MR. DAVIS: So they will not try to redraw these curves; is that correct?

MS. SOBEL: To my knowledge, there will be no recalculation of these curves.

MR. DAVIS: Okay. That was not my understanding.

MR. MURPHY: This is Andrew Murphy of the Research staff. After the resolution program, which is what you are referring to, is done, it is our intention that if that program has produced reasonable looking results to go ahead with some recalculations.

MR. DAVIS: How do you know if they will be reasonably looking results, if they agree with yours, you mean?

MR. MURPHY: Expert judgment.

MR. CARROLL: So there.

[Laughter.]

MR. SEALE: We know all about that, don't we, Bill.

MR. LINDBLAD: We expect to have some comments from industry and perhaps if industry provides some food for thought, perhaps Dr. Sobel or Gutam or B.D. will want to respond to it.

MR. WILKINS: May I ask, Dr. Sobel, you had two different classes of experts. You had experts in geology, seismicity and the like, and you had experts in elicitation, ground motion. No, you had experts in elicitation. There were three classes, but I want to lump those two. You had experts who knew something about the subject matter, and you had experts in elicitation, and I am just wondering whether any of your elicitation experts knew anything at all about geology or seismicity or ground motion, or anything of the sort?

MS. SOBEL: They had known something about it, but they were not experts. Part of the purpose of the workshop was to give them a background in the procedures.

MR. WILKINS: To give them a background in the geology and the seismicity, or to give the technical experts a background in expert elicitation, which way did it go?

MS. SOBEL: We wanted to give the experts on expert elicitation a background in how a probablistic seismic hazard estimate is calculated. We wanted them to know how the experts choose their inputs and how the computer code uses those inputs.

MR. WILKINS: But you didn't want necessarily the experts in elicitation to learn anything about geology?

MS. SOBEL: No.

MR. LINDBLAD: Mr. Chairman, I have had the same thought myself, and so I have read the references, and it appears that the journal that reports on expert elicitations, called the Journal of Management Science, and you will remember that Dr. Lewis identified a year ago that this actually was a science.

MR. LEWIS: There is even an institute for mathematical sciences. That's right.

MR. LINDBLAD: Thank you, Dr. Sobel. If you could stay with us a few minutes, we will see what NUMARC would like.

Is David Modeen going to be the opener?

Mr. Modeen, if you would take a minute to introduce yourself and where you learned everything you know.

MR. WILKINS: Mr. Modeen, it is a simple question, what did you know and when did you know it?

[Slide.]

MR. MODEEN: I am Dave Modeen with NUMARC, and I might point out that as of Monday it is Nuclear Energy Institute instead of NUMARC. I forgot about that. In fact, just before coming up here, I had an E-Mail that told me that my new phone number effective Monday is 739-8000, so should you need to get in contact with us, the other one won't work.

MR. WILKINS: Will you repeat that new organization's name again?

MR. MODEEN: Nuclear Energy Institute. I didn't mean to get of the subject, but basically that is an integration of the four industry organizations supporting the nuclear industry in Washington.

MR. LINDBLAD: You had better watch out, the next step is downsizing.

MR. MODEEN: I think that is part of it, no doubt about it.

I hope to make my remarks brief this afternoon and be followed by Tom O'Hara from Yankee Atomic and John Reed of Jack Benjamin Associates.

Let's see, where did I learn everything, I know very little about this subject, and that is why my remarks should be brief.

Basically, I think, as Dr. Sobel had indicated, the purpose of our meeting is to follow-up on a couple of the comment letters as the industry viewed the revised Lawrence Livermore hazard estimates as it relates to the IPEEE. There is one more letter that I know has been faxed to the staff dated March 3rd that I believe she has not had the opportunity to see, but it is NUMARC's remarks in relation to this, and that I think kind of sets the stage for our presentation.

MR. WILKINS: That is the letter, by the way, members, that is included in this Handout 14.

[Slide.]

MR. MODEEN: Just by way of background, I know this committee was very interested in the IPE and IPEEE process over the years, and I would just remind you the types of comments that the industry provided on that program was, one, we recognize that a generic letter allowed much flexibility for licensees and that it was really up to the licensee to consider its specific plant situation, location, design, vintage, et cetera, in proposing how it would respond to that generic letter, as well as suggesting alternatives, if appropriate.

Another point in our comments is that at least as compared to the internal events IP in which the industry was very positive on the value of that program, there were certain aspects, especially in the area of the seismic part of the program, where certain analytical calculations and things seem to have a less practical value from the standpoint that once you learned some information, would you really do anything with that information, or would it make your plant ultimately any safer.

Then, of course, the fact that we had more confidence, I think, in the EPRI hazard estimates, at least as compared to the Livermore '89 results. Consequently the recommendations in the industry was to customize their examination plans to their particular site and plant vintage, as well as, I think, a recognition that the walkdowns was going to be the most beneficial aspect of the seismic portion of the IPEEE. I think this last bullet here, the gentleman that follows me will spend a little bit more time on that, developing that thought.

[Slide.]

MR. MODEEN: Looking at least from NUMARC's perspective, what has occurred since 1991, an issuance of the generic letter, there are several things that I think bear on the letter that we provided to the staff of March 3rd. The first is, the NRC's what was previously termed the Program for Elimination of Requirements Marginal to Safety -- I understand that has a new title of Regulatory Improvement Program -- the intent of that, and there was a comment period, I think, approximately two years ago that said there was a recognition on the part of staff that some regulations weren't optimized, some other requests out there weren't necessarily -- the benefit wasn't commensurate with the cost. I know at least from the industry point of view, we got many requests from people to reconsider generically addressing the IPEEE with the NRC staff, but we didn't feel like we had anything more to say than what we had already said in the '88, '89, '91 timeframe, so we hadn't done anything.

The second point is, when I look at what is going on with trying to, I think in a practical way, implement the safety goal policy, when we look at some of the insights that have been derived in the Part 100 rulemaking process, and here I am also referring to some work that was performed on behalf of NUMARC on the non-seismic criteria that the staff had, as well as the draft revision that was out for public comment last fall in trying to take risk measures and values indices into, I think, the normal practice in looking at generic letter requests as well as forward-looking rulemaking packages.

Then probably the most recent one is the report sponsored by Frank Gillespie which I know this committee got several briefings on, which was the Regulatory Review Group, that indicated that there were many things in which the cost beneficial licensing actions of individual licensees should be able to one by one go into the staff and get relief from things that just seem to be a good idea or a good commitment at the time, but based on new information or otherwise doesn't, again, really provide the commensurate safety benefit.

Then finally I think specifically more related to the actual engineering aspects of the seismic program is the experience gained to date in the industry, although not many IPEEEs have been submitted, there has been quite a bit of work on them. There has been work previously, and then the draft NUREG 1488 which you just received a briefing on.

[Slide.]

MR. MODEEN: That consequently led to two letters, one to the industry also that was sent last week, as well as the one to the NRC staff that we said, all these things taken together indicate to us that licensees may want to consider the IPEEE as a candidate for a cost beneficial licensing action and yet at the same time we recognize the difficulty in trying to address IPEEE on a generic basis for all sites, either for us or the staff, and suggested that we did not think it was an appropriate use of our resources or the staff's to try to alter the guidance that exists out there on the IPEEE. We don't see a need for that from the standpoint of the licensees and didn't really want to get into some protracted dialogue interactions and the necessary chain of events that would follow.

Alternatively, we informed the staff as well as the industry that we are documenting the rationale for this CBLA in a white paper that we would provide to the staff and the industry in the very near-term. I expect that to be by the end of this month, and that it would then be up to the licensees to consider that information, consider the 1488, et cetera, and to make their case on a case-by-case basis.

The presentation that will follow first with Tom O'Hara, the essence is to give you really the basis of what is in that white paper that we have as a draft.

With that, I will turn it over to Tom.

MR. LINDBLAD: I don't know why Mr. Modeen wouldn't say it, but before he came to Washington, he got his industry experience in Portland, Oregon, at the knee of the masters.

MR. WILKINS: You have just explained why he didn't say it.

[Laughter.]

MR. MODEEN: No comment.

MR. CARROLL: I did notice he was a good talker.

[Laughter.]

MR. CARROLL: I didn't say anything about the substance, just that he is a good talker.

[Slide.]

MR. O'HARA: My name is Tom O'Hara. I am from Yankee Atomic. My background is that I did calculate all of the EPRI seismic hazard calculations for all the Eastern U.S. sites. My background is in statistics. I have been down here before. I think that is enough.

MR. CARROLL: What kind of statistics, are you a basion or are you a classicist?

MR. O'HARA: No comment.

What I want to do is go over the progression of the NRC Livermore seismic hazard analyses that we have had to live with over the years, then John Reed is going to come up here and discuss the lessons learned from walkdowns. He is also going to discuss some conservative bounding methods to estimate core damage frequencies that we are going to be using. Then I am going to discuss some quantitative acceptance criteria, and I will have some conclusions.

I appreciate that what we are going to be saying here, we are going to be using words like "binning" and "reduced scope" and "focus scope" and "full scope," and these are associated with the IPEEE process here. Just bear with us.

When I was at church this last weekend, the minister had a long, long spiel, about a half an hour, and after it was all over my son said, what did he say, and I will tell you right now what I am going to say, which is that based upon our review of this new significant information that Livermore has put out, we believe that only about a handful of plants should be doing a full scope or focused scope type of analysis, the rest should be reduced scope.

[Slide.]

MR. O'HARA: This is the history. These are the studies that we have to deal with here, 1582 basically documented the SEP, the Systematic Evaluation Program results. After that, there were four studies from '84 to '93. I will discuss those, but the first one I want to discuss in detail is the 1981 study.

[Slide.]

MR. O'HARA: Before I go into that, I just want to show you one slide that I think you have seen before, many of you may have. I am sorry for the low ones, but basically what you can see here is that over time -- this is courtesy of Paul Smith. This is way back in 1984. As you go to 993, the hazard has reduced. There is no question about it. These are Livermore results, not EPRI's.

MR. WILKINS: I think you don't want to say what you said.

MR. O'HARA: The hazard hasn't changed. I agree with you. It is a good point, but the problem with that is that the perceived hazard was high and, therefore, you had to find margin, et cetera. But the perceived hazard has been reduced significant y over time.

[Slide.]

MR. O'HARA: I want to discuss this NUREG 1582. This 1582 basically had its genesis back in 1978, that is when the site-specific spectrum program was initiated, and TERA Corporation, that is T-E-R-A not t-e-r-r-o-r, but as far as we were concerned it was terror, they began these analyses. The purpose of the analyses was to sort of evaluate seismic hazard parameters, develop a methodology and test it out.

In December of '78 the program was expanded, all the SEP programs were brought in, and they also brought in ten seismic experts.

In August of 1979, they published some results, the results were very high. Alan Cornell, he commented on this and he said, this doesn't agree with anything I have seen in the past. These are very high results. Larry White from TERA Corporation -- I say this because I have a letter from Larry White -- Larry White said, these results are interesting, but it is somewhat of an academic study. If we used the parameters that we think are appropriate, you would get much lower results.

Nevertheless, there were sensitivity studies done beyond that, and basically we got a letter back in 1980, we were an SEP plant, and it said, here is your spectrum, this is your 1,000 year spectrum, go forth with it. There wasn't that much difference between the 1979 results, the August '79 results and the '80 results.

After that, there was a transition whereby Livermore took over from TERA Corporation.

[Slide.]

MR. O'HARA: What I want to do is show you, there were four studies from 1984 to 1993, and there were ten test sites that were used in these studies that are common to the four studies. You can read them up top here, Braidwood through Maine, two of those are not Appendix A, in other words licensed to current criteria, they are Millstone and Maine Yankee. The remaining ones are Appendix A plants.

What you can see here is that the perceived hazard has clearly been reduced over time, yet the trend from site to site is about the same. Why do I bring this up? The reason I bring it up is because the way that you did the binning for IPEEE were these relative comparisons, and guys that are at the top are always going to be at the top, and guys at the bottom are always going to be at the bottom.

In a relative context, that just doesn't help you. At some point, you have to go on and make decisions based upon some absolute or quantitative measure.

This red dot right here, that -- by the way, if you go down these dots right here, that reflects that original figure that I showed up there. That is the Millstone site. The red dot represents the 1,000-year spectrum that was in the 1980 letter from the staff to Millstone, and the hazard is on the order of about three times ten to the minus five, 1993.

MR. LEWIS: What are the lines for? What is at Site 4.37?

MR. O'HARA: Tell me where it is?

MR. LEWIS: There is no site 4.37. Why are the lines connecting?

MR. O'HARA: That's right. These dots represent these sites. I am just trying to show the trend. It is easier when there is a line in there.

MR. LEWIS: But there is no trend because there is no connection between the sites.

MR. O'HARA: When you go across this way, when you go across, I am just trying to show the trend in the sites, and then you look below it. I am just trying to show a trend, nothing more than that.

MR. LEWIS: But there is no trend.

MR. WILKINS: Some of those lines look like they are roughly parallel, and that says that no matter how you measure, no matter what you do, Site A relative to Site B is --

MR. O'HARA: I contend this site here is always lower than that.

MR. WILKINS: And by about the same fraction except that those lines are parallel, and your eye can assess that more readily if you draw the lines in than it can if you don't, and that is all that represents.

MR. LEWIS: We will discuss this.

MR. O'HARA: Thank you very much, I appreciate that.

MR. SHACK: I noticed that the EPRI and the 1488 results seem close for every plant except Maine, but the EPRI Maine is way up at the top there?

MR. O'HARA: I am sorry, I blundered there. You put all these sites together, that dot, that X for Maine should be right about there. Thank you for bringing it up, I forgot to point out that these little, little specs down here are the EPRI results.

MR. DAVIS: I may have missed it, but what is the probability of for each point?

MR. O'HARA: It is the probability of exceeding the SSE.

MR. DAVIS: And the SSE is not the same?

MR. O'HARA: That's right, it is not the same for all sites. Two other points I want to bring up here. These are based on medium hazard results to be consistent with what was put forth in the SEP program. Also when I say probability of exceeding the SSE, what I am saying is this, the SSE I am defining it by the 5 and 10 hertz spectral ordinates. I am calculating the probability of exceeding 4 hertz, or 10 hertz, and then taking the average. I don't think the staff has any problem with this process.

Anyway, I find this comparison to be relatively interesting because it shows how the trend in the perceived hazard has certainly decreased over time, but the bottom line is how do you use hazard in a relative sense, and that is a problem we have had, how we use this to make decisions.

MR. DAVIS: It shows me something else, and that is that the selection of the SSE was not based on the seismic hazard.

[Slide.]

MR. O'HARA: You just said something that I find -- I appreciate what you just said. This here is, I have the 1993 results on this solid line here. This dashed line represents those nine sites I showed on the previous slide. These are the 1984 results, these are the 1993 results, and what you just said was, what we don't have is a consistent probability of exceeding the SSE from site to site to site, and I agree with you totally.

In my opinion, and I was here a couple of years ago, the problem with this is the deterministic process. I believe that is a root cause of many of our problems, but that is another issue.

MR. LEWIS: Let me just say that a while back, one of the people we had here, Shiv Seth and I published a complete list of the SSEs and the historical seismicity at the sites to just test that issue, and he is absolutely right, it is just not rationally chosen.

MR. O'HARA: Thank you.

What I am showing here, these are the Livermore results, the median results, this is the '84, and I have no reason to believe that if they did the hazard for all sites back in 1984 it would look something like this, only about a factor of 10 to 100 higher across the top.

MR. LEWIS: So then for this one you don't have the excuse for drawing the lines between the sites.

MR. O'HARA: Okay.

[Slide.]

MR. O'HARA: Somebody asked the question of Phyllis, how do the results compare with EPRI? These are the median hazard results. These are all the sites, and I have the site numbers, if you want to know who they are, and your probability. The dashed line is the medians for EPRI, and the solid line is for Livermore. What you find is that there is excellent agreement between Livermore and EPRI.

What NUMARC would say is that this certainly confirms our belief in EPRI.

The point is, the Livermore results are in real good agreement in terms of the medians, and I will show you the means in a minute. The question you have to ask yourself is, what do you do with this kind of stuff, how do you make decisions? What you can see here is that -- you know, I missed an important slide here on this thing. Just a second.

[Slide.]

MR. O'HARA: I want to back up just for one minute, if you would just bear with me. Remember that study we talked about, the 1982 SEP study, in that study we got a letter from the staff, and it was to the SEP owners. In there it said, these return periods of the SEP spectra will still be able to be described of as of the order of 1,000 to 10,000 years, which is the present description of the spectra and the level implicitly accepted by the staff by NRC in recent licensing decisions.

I also want to bring up that it was way back in this SEP this whole notion of relative ranking was brought into the picture, and I will just give you an example. We wrote a letter -- I wrote a report, Alan Cornell and myself, critiquing the Livermore results, and we said that these results, we believed, were probably conservative for a lot of different reasons, and the response was, is it consistently conservative from site to site? The answer was, yes, we believe it is. Their response was, as long as the net doesn't affect the hazard, the relative hazard from site to site will be the same, and that concept has carried through from way back when in the SEP to the present. We use these results in a relative fashion.

[Slide.]

MR. O'HARA: So what I was going say here is, here I have these median hazard results for all the sites, and how do you make a decision. If you talk about this 1,000 to 10,000 year return periods, there is only a handful of plants that have the probability of exceeding the SSE above that.

How do you make decisions using medians, and you can't. You have to go on. If you want to get core damage estimates, we need some quantitative measure to make decisions. We have to be talking about means. What I want do is just show you how the means between Livermore and EPRI have come together over time and then we are going to recommend an approach to make decisions based upon some quantitative measure.

MR. LEWIS: But to relate the median to the mean, you will then have to provide a distribution?

MR. O'HARA: I am not going to relate the median to the mean, I am going to use means.

MR. LEWIS: I thought you said you were.

MR. O'HARA: No, I am not. I am going to use means.

[Slide.]

MR. O'HARA: Why didn't we use means before? Here you have your 1989, the top solid line is the 1989 values using the Livermore mean hazard curves. These are the EPRI hazard curves. What you can see is that the agreement between Livermore and EPRI is not good.

Furthermore, if we did some kind of core damage calculation and we have a Livermore number of, say, two times ten to the minus three, and we have an EPRI of two times ten to the minus five, the answer is going to be ten to the minus three when you average the two.

MR. LEWIS: Tell me that what I am about to say is nonsense, I hope. It looks to me that the way you went from the median to the mean is that last time you used to ask people about the median and now you ask them to estimate the mean.

MR. O'HARA: No, I didn't. This here, the mean, is a mean hazard curve.

MR. LEWIS: Mean of what?

MR. O'HARA: You have a distribution of hazard curves. When you have a site, say we are talking about the peak ground acceleration, you have a distribution of hazard curves, and out of that distribution you have the mean, the median, the 85th, the 15th.

MR. LEWIS: That is a distribution -- I am now really lost. You have a distribution because different people are estimating the hazard?

MR. O'HARA: Absolutely.

MR. LEWIS: Okay, so you are taking a mean of experts weighting each expert equally.

MR. O'HARA: Yes, that is correct. No, I am sorry. The way Livermore did it was self-weighting, I do believe.

MR. LEWIS: Was what?

MR. O'HARA: Self-weighting. They were given I want to say an attenuation. Are you an expert, yes or no. I can't answer this question, Jean could, as to how the weight was done with Livermore.

MR. LEWIS: But it is very important on how you do the weighting, and weighting experts equally is one way. The other way is to ask the experts to rate each other for ability, and you get different answers with a wide distribution like this.

MR. O'HARA: I do agree with you. But given the way they did it, you end up with a distribution, and the distribution comes from not just attenuation but there is uncertainty in terms of --

MR. LEWIS: But the weight function that goes into the distribution plays an important role in the result, so after a while you start giving talks like this, and people begin to believe that the distribution represents something.

MR. O'HARA: I don't disagree with you. The point is, there is a methodology. They came up with some way to facilitate an expert's weight on a particular topic and you have to use it. We can debate how people develop weights.

MR. LEWIS: Forgive me, there is another step, which is, if I am trying to protect the health and safety of the public, it takes more than agreement between us about how to do these calculations to do that, we have to relate to reality somehow.

MR. O'HARA: I agree with you.

MR. LINDBLAD: It seems that Mr. O'Hara doesn't know how Livermore did it. How did EPRI do it?

MR. O'HARA: I don't think it is worth getting into because every one of these parameters has a weight associated with it, and that is how you end up getting your distribution based upon the weights, and it is a whole other topic.

MR. LEWIS: But it is an important one because you don't want to get into the Emperor or China, you know the way to estimate the height of the Emperor of China within a tenth of an inch is to ask enough experts, and you don't want to do that, and you would be suckered into it by going through this and skipping the fundamentals every time by saying, we don't have time to get into the, but let's skip them.

MR. O'HARA: The point I would like to make here is that this is your '89 mean hazard results at each of the different sites. These are the '89 EPRI results. The reason you couldn't come up with some sort of quantitative measure of core damages, there is a huge difference between Livermore and EPRI. How do you handle this, and I believe you handle it like they handled it. You do relative ranking, you do the best you can.

Let me show you what 1993 Livermore looks like relative to the '89 EPRI.

[Slide.]

MR. O'HARA: I think there is a little better agreement here.

MR. LEWIS: Is that good or bad?

MR. SHAO: Good for him.

MR. O'HARA: Yes, that is a good point, it is good for me.

MR. LEWIS: No, seriously, have you managed to obscure a genuine uncertainty through the mob instinct, is that what has gone on here?

MR. O'HARA: No, I do not think that is the case. What I said to you before, and I still believe it to this day, is that -- I don't want to say they did it wrong, but they did it wrong in my opinion, and I think that these are valid numbers.

MR. LEWIS: I have no problem with saying that somebody did something wrong. I say it to students all the time. The difference between you and me is that I know the answer.

MR. CATTON: Sometimes you even say we do it wrong.

MR. O'HARA: Livermore, they didn't make these changes because -- and they don't help.

MR. LINDBLAD: I think, Mr. O'Hara, that you are trying to explain that if accepting the results, if you will accept the results, what do we do with it, and I think that Dr. Lewis is rightly saying he still has some questions about the credibility of the results regardless of what year they were done, or what organization did them, and that is fair, but you are not there to explain that.

MR. O'HARA: That is exactly right.

MR. LEWIS: But I am also making a point I made at the very, very beginning, people tend to dance with joy if two experts agree with each other. That doesn't mean they are right.

MR. LINDBLAD: That's right.

MR. O'HARA: I agree with you. This is far from two experts, of course, these are large, large studies.

MR. LINDBLAD: If you are not going to defend the studies, I suggest you really go on.

MR. O'HARA: No, I am not going to, not at this point. I am just going to show two more slides and let John get up here.

[Slide.]

MR. O'HARA: This I find to be an interesting slide, so bear with me. These solid dots, they represent the probability of exceeding a .3g NUREG 0098 spectrum. I am using the 1989 mean Livermore results. The .3g spectrum is the review level earthquake of IPEEE. These open circles represent the probability of exceeding the SSE at existing sites, and this is based upon using the 1993 Livermore results. In almost all cases, you will find our, as you can see, that the probability of exceeding the SSE is less than this higher spectrum.

MR. CARROLL: Why is it higher for Site Number 66?

MR. O'HARA: I can't answer that question, I haven't looked that closely. That is just a comparison I made. What it says to me is that the review level earthquake ought to be the SSE, not .3g.

[Slide.]

MR. O'HARA: What we are arguing for, basically, is to go on and come up with some quantitative measure. This means actually sort of believing the results. Mean core damage estimates, what we are saying is the detail walkdown ensures the SSE. John is going to discuss that. Conservative plant fragility parameters, they are based on the SSE. We are going to use Livermore and EPRI, that is what the staff has said we have to use, and these more refined core damage estimates, we believe, if you did more refined analyses we would get lower numbers than what we are going to show you after John gives his presentation.

MR. LEWIS: John, are you going to explain means and medians to us?

MR. REED: No.

MR. LEWIS: Then I won't ask you to.

MR. REED: I am John Reed. I am with Jack Benjamin and Associates. I am a structural engineer, and I have been involved in the last 10 or 15 years with seismic probablistic risk assessment and seismic margin assessment.

Where this talk is headed is, what we want to do here is take these new Livermore results and we want to make an estimate at every one of these sites of what the mean core damage frequency is. We are not going to look at SSEs, people say that is a point estimate. What really matters is what is going to happen to the plant.

So to be able to do this, we need to talk about the capacity of the plancs. We have been talking about the hazard, let's talk about the capacity of the plants.

[Slide.]

MR. REED: First, I want to make a point that is extremely important, and one that sometimes gets missed, and that is when you do a review of a nuclear power plant for the effects of seismic events, the most important aspect of that review is the plant walkdown.

This opinion, this position, was first expressed by the NRC expert panel back in the early 1980s, which I was a member of, that was charged with the responsibility of asking a question that you people put forth, how much margin exists above the SSE? Is there a cliff there? So we developed this methodology that we call seismic margin assessment. The core of that methodology was the plant walkdown.

Since then, lots of additional seismic PRAs have been done, there has been additional seismic margin assessments. A lot of people have gotten into the IPE, seismic IPE work, and they are doing similar studies. It is still the opinion of the engineers today that the most important aspect is the walkdown.

Now what has happened over the years is, we have done a lot of studies. We have done a lot of SMAs and PRAs, but there really hasn't been that many hardware changes that have taken place. There have been very few, relatively speaking. But in every case, when there has been a hardware change made, that problem has been discovered during the walkdown. Now, true, after it has been discovered there has been analysis performed, HCLPFs have been calculated, median capacities if it is a PRA, but there have been no surprises.

No guy has come out of his office and said, by gosh, I just did an analysis and I have discovered that this thing needs to be repaired immediately. If he has come out of his office with that, the walkdown team has already made that conclusion. So the walkdown discovers these things that are really important.

Now going on to the seismic IPE program, I am not sure how familiar you are with this program, but there are basically three levels of review, a full scope, a focused scope and a reduced scope. As the words suggest, as you go from full to reduced, the level of effort changes.

But in all cases, in all three types of reviews, the selection of the components that are reviewed is exactly the same. You either do a seismic margin assessment or a seismic PRA. If you do a seismic margin assessment, you use a success path approach to select the components. If you use the fault tree or event tree approach, you select the components that way. It is the same.

Once you have selected the components, the actual walkdown is the same for all three levels of review. Where the difference comes in is when you discover an outlier, a suspicious component. If you do a full scope or a focused scope review, you go calculate. You calculate a HCLPF if you are doing a seismic assessment, you calculate a median and a logarithmic standard division if it is a seismic PRA. If it a reduced scope plant, you go and check it against your SSE, your requirements for your licensing basis. In that, usually you have documentation in your files. You can go pull the documentation out. You can check to make sure that the calculations were done properly. That is considerably less effort than calculating HCLPFs or median capacities.

So this whole talk, this whole presentation today is coming to the conclusion that because the seismic hazard has been reduced significantly, we should not make plants that are in low seismic environments do more than the most cost-effective steps, those being selection of the components and walking down the plants.

MR. DAVIS: John, how important is the quality of the team that does the walkdown?

MR. REED: Very important. I have some words to say to that.

[Slide.]

MR. REED: First of all, in this walkdown the team, first of all, has to be competent. There is no question about that at all. In my second bullet I will say something about where we are in competence these days. But the point is, the team, whether they are doing a full scope, a focused scope or a reduced scope, it doesn't matter, their job is going to be the same. They need to get out there. They need to get down and get their knees dirty. They need to open cabinets and look inside.

The issue is anchorage, is seismic spacial interactions, it is things that you can only really properly evaluate by getting in the field and getting yourself well involved with the plant.

We have come a long way since 10-12 years ago. We have a lot of information today. I didn't want to spend a lot of time on this, but I will just say, there have been a lot of reports that have been prepared. There is NUREG 4334, there is EPRI Seismic Margin Report, there is the GIP. There are training programs that are going on as part of the A-46 program. I have been participating in training programs for seismic margin assessment that are follow-on to the A-46 programs. I would guess today the people that have gone through these programs number in the two to three hundred type.

So I really feel that today there is the capability out there to do this competent type of review, but whether you do full scope or reduced scope, it doesn't matter. You still have the same issue which you have to address.

My thesis here is the following, that once we complete the walkdown process, and we will do one of two things at that point, either we will have confirmed that the component in a reduced scope event is qualified for the SSE or, if we find a problem, and this has been the history, utilities just go out and fix it. If you find a cabinet that has an anchor that is not tight, if you have on that is broken, if you have a burn-through on a weld, they don't go calculate for it, they just go fix it.

At that point, we can confidently say, for those components that are in the success path, we can say that they qualify for the SSE, and that, to me, and I know to the members of the NRC panel that developed the seismic margin methodology, is one of the most important things that we hoped would take place for all of the plants.

MR. WILKINS: Bill, we are getting close to 4:30.

MR. LINDBLAD: How close are you to finishing?

MR. REED: It is going to take me about six more minutes, and then Tom has to come back and talk about how we use the capacity of the plant to make core damage estimates, and that will be another ten minutes. So we are probably talking 16 or 17 minutes.

MR. LINDBLAD: Why don't you try to get finished in five minutes.

And while you have this time, Tom, would you try to shorten your presentation to about five minutes.

MR. REED: We are at the point now, we have walked down the plant and we are confident that the plant satisfies the SSE. What I want to do now is, I want to use that as a basis to make an estimate of what the fragility curve looks like for the plant, and I want to make a very conservative estimate. We can allow ourselves this luxury because the EPRI and Livermore hazard curves are low enough that we can be very conservative and we can still demonstrate that the risk of many of the plants, not all of them, but many of the plants are low enough that it is reasonable for them to do this reduced scope program and not spend the extra money doing calculations that are not needed.

[Slide.]

MR. REED: So I will move a little quicker than I would have normally and say to you that there is margin. There is no cliff right at the SSE. There is capacity above the SSE. What we have found from past studies that for individual components, structures and equipment, and we know the SSE, we know that the median capacity or the median factor of safety, if you will, is on the order of 4 to 12 times for structures and something like 4 to 20 for equipment. This is what we have observed from past seismic PRAs and SMAs. If we don't look at that, if we just go to our code requirements, the ACI Code for concrete, the AISC Code for steel and we look at the margins that are built into the code requirements, we find that there are minimum capacities, two-and-a-half to five times the design level, in this case the SSE. Things don't get built according to minimum capacities because of construction constraints, because of other loadings and so forth. That is why when we really go and look, we find these higher values in most cases.

However, when you look at core damage, it is the weakest components that control the core damage fragility curve. So we find there that the median capacity is roughly three to six times the SSE. It is the lower components, the weaker ones that propagate to the surface and control.

[Slide.]

MR. REED: Now I could quit at that point and just say, well, we got the job done. We know we have a median capacity here that we will say is three times the SSE, and go do our analysis, okay. But another approach at this is to go back and look at areas that are more familiar with the structural engineer. We talk about this HCLPF, this high confidence of a low probability of failure. This is a capacity that is higher than the SSE but it is not a huge capacity. It is within the experience of structural engineers. What we have found there is that for these weaker components, and we are looking here now at the core damage fragility curve that is controlled by these weaker components, we find that our HCLPF capacity for our core damage fragility curve is 1.2 to 2.5 times the SSE. That is just based on past studies.

For the purposes of this study, we are going to pick the HCLPF as being 1.25 times the SSE. We are going to pick a value down at the lower end. I feel fairly comfortable in being able to defend after I have completed my walkdown of this level.

[Slide.]

MR. REED: Now, if we go look at core damage fragility curves, and I brought one along here that unfortunately was one we put together this morning and is very, very crude, and it is not the way most of you would see these. They couldn't draw a squiggly line for me, so they put in three segments, but this a core damage fragility curve.

If we look at the slope of that curve, we find from past seismic PRAs that this value is like about .3 to .4, and it is very, very tight, and very, very consistent from study to study. So coupling that with our HCLPF being 1.25 times the SSE, we basically come to the conclusion that a very conservative median capacity for the purposes of this study is just to say that our median is 2.67 times our SSE, and we will use a beta C of .33. All again, hinging on our assumption that the SSE has been verified by the walkdown.

With that, we can literally now take the hazard curves from all these plants and we can calculate the core damage frequency. That is what Tom is going to show you the results from and where we are.

MR. LINDBLAD: Thank you, Mr. Reed.

[Slide.]

MR. O'HARA: Based on these generic conservative upper-bound plant fragility curves, we combined those with the mean hazard curves, and the top results are based upon the Livermore '89 and the EPRI '89 results. The solid dots represent the reduced scope plants. The bottom solid line represents the combining of those generic plant fragility curve with the mean results of Livermore '93 and EPRI '89.

What one can see from this slide is that all but one of the reduced scope plants are above five times ten to the minus five. We picked five times ten to the minus five as a cut-off criterion, and let me just go over the reasons why.

I can come back to this slide, if you wish.

MR. LINDBLAD: No.

[Slide.]

MR. O'HARA: Justification and criterion for reduction in IPEEE program. First off, there is no doubt that there has been a significant reduction in the perceived hazard. The walkdown is clearly the most cost effective and beneficial aspect of the IPEEE seismic program. Since we are using conservative upper bound core damage calculations, you are only going to but do better than this.

We have conservative input assumptions, mean hazard curves from Livermore and EPRI. As I say, more refined core damage estimates will be lower.

Core damage precedent we looked in NUREG 1407, which is the IPEEE submittal, the average core damage seismic contribution is about five times ten to the minus five. In NUREG 1150, the average seismic contribution is about five times ten to the minus five. We reviewed some 55 IPEEE internal documents, the average core damage contribution is about six times ten to the minus five.

We believe that, five times ten to the minus five, plants that are lower in probability than this value should be reduced scope plants.

[Slide.]

MR. O'HARA: The conclusions, just a regurgitation of what I said, which is that there is no doubt that the hazard is lower in Livermore '93. The walkdown is most effective, it is cost beneficial. We use conservative upper bound core damage -- conservative input parameters to estimate core damage. We believe that more refined analyses would only but result in lower core damage numbers.

[Slide.]

MR. O'HARA: Core damage, there is some precedent for five times ten to the minus five. We believe that it should be reduced scope for all but a handful of plants. The cost savings from focused scope to reduced scope are significant, about $250,000. The benefit is not justified for this expenditure, and we do believe that the reduced scope effort satisfies the generic letter and the request for information.

That is the quick and dirty of it.

MR. LINDBLAD: Thank you very much. Thank you for trying to live up to our time commitments.

Mr. Liaw, is there anything that you wanted to close the sessions with?

MR. LIAW: Not really, but just a couple of observations I would like to make.

First, we are totally agreed that walkdown is extremely beneficial or cost effective, in a sense.

I also want to share something with you. One time Dr. O'Hara kept mentioning about his hazards, he always compared to the SSE, and when he proposed the HCLPF curve of 1.25 SSE, as we know the statistical uncertainty, 1.25 is really not much.

I would like to share with you about what actually happened out there. I recently ran into this situation at Watts Bar. They have these six three-quarter inch undersize weld for socket welds, and he proposed to do a finite elements analysis instead of fixing it. The reason I am sharing that with you is, if you are out there, they are not uniform. I will be glad to entertain all of them. If we find something, we could fix them, and they would all go home free and happy. I hope that is the outcome. But in reality there are 50-60 utilities out there, a couple of hundred plants out there, not every one of them will do the same thing.

In terms of staff response to the industry request, I can assure you we will be reasonable and we would intend the good argument. At Palo Verde I think recently they have successfully made an argument and we have agreed to reduce it to a different lower bin. I don't remember exactly which bin they were. We have been sitting down with Mr. O'Hara and Vermont Yankee, and we are undertaking the review of their data, and certainly hope that we can come to some kind of conclusion as soon as possible, and also we are receiving requests from Commonwealth's plant, I suppose. We will take that kind of review.

Again, I can assure you that staff's mind is open, and we all grant that the perceived hazards is lower. So I guess that is all I want so say.

MR. LINDBLAD: Thank you very much, B.D.

Mr. Chairman, I will return it to you. It was not my intention that we would develop a letter, should any members contemplate that, we could discuss it, but it wasn't my intention.

MR. WILKINS: All right, I would like to --

MR. CARROLL: Would we develop a letter at some time in the future when it becomes a bit more ripe as an issue?

MR. LINDBLAD: My remark only applied to the moment, yes.

MR. CARROLL: All right.

MR. WILKINS: It sounds to me like your answer is, you don't wish to exclude that possibility, but you are not asking it yes either.

MR. LEWIS: Will it be possible to get some of the supporting documentation of the Livermore report, the EPRI reports, because it would help me a great deal to see what the originating people actually say about what they did.

MR. LINDBLAD: Yes. As I understand it, Livermore prepared a report and Dr. Sobel did put a special report in on the elicitation process that I think you are very interested in. Of course, there is this NUREG 1488 that I think you have a copy of, or there is additional copies, but they just show results and do not discuss elicitation.

MR. LEWIS: Well, I am interested in going as far back as I need to to understand the process. The results I have heard many times. So a list of results will not be helpful.

MR. BAGCHI: Dr. Lewis, you probably want to start with EPRI results, EPRI's study. That is an eight volume work. I think it would be a good idea to start with the EPRI studies, though.

MR. LEWIS: I can skim pages as well as anybody.

MR. BAGCHI: We can make some of those exhibits

MR. LEWIS: If there exists no concise statement of the methods, then that means nobody understands the methods, because if you have something clearly in mind, it can be written in fewer volumes than that.

MR. LINDBLAD: The eight volumes he is speaking of are geological descriptions.

MR. LEWIS: Yes, I am not worried about that.

MR. BAGCHI: Everything is in there.

MR. LEWIS: I want to know what is done with the data that are accumulated. When people use the word "mean" but they "mean among people" that worries me.

MR. WILKINS: Let me add my thanks to the staff and to NUMARC for those presentations, and we will now move to the next agenda item.

We are off the record, are we not? Not quite.

MR. MICHELSON: It is my understanding that GE has a commitment that they wish to make, and I would like to keep it on the record just for the record, as to when and what kind of material we will receive relating to Amendment 34, and if GE is prepared at this time, I would like to get that on the record.

Then we will be finished with the record.

MR. WILKINS: Mr. Beard.

MR. BEARD: This is Alan Beard with GE Nuclear Energy.

In light of information that became aware yesterday, I guess that is the best way to put it, we recognize that there is a problem with getting an April letter out. GE definitely is interested in supporting whatever effort is needed to enable the ACRS to issue that letter out in April. To that, we have examined what things we can do to provide you with the information for Amendment 34 to support that.

In side discussions we have had with various members, both the staff and ACRS, what we are proposing, and this is just a slight modification to what I indicated yesterday, is that we will give you the draft markup versions of the technical issues that are going to appear in Amendment 34 that respond to the ACRS concerns we feel have not been responded to in previous amendments.

We are currently undertaking an effort to identify all that stuff, to pull the packages out, Xerox them, and to transmit them back here to the ACRS. Right now we are trying to do that by Wednesday next week. Certainly we expect to ship the package no later than Friday of next week. There would be a slight possibility that additional information may follow part way into the week after that, but we are shooting to get everything out by Friday of next week.

In order to also be able to issue the letter out with not having reviewed Amendment 34 as a formal issue document, what we are proposing is that the markups we sent to the ACRS we will also provide a package to the staff, and the staff has agreed, as I understand it, to take that markup package and to verify that the information we are giving to you as markups shows up in the formal Amendment 24 submittal.

MR. WILKINS: If I look at my calendar and you mail it a week from today, it should be in Bethesda on Monday the 21st of March.

MR. BEARD: That would be correct. We will FEDEX it and we will send the obvious copies to that half.

MR. CARROLL: How big a package do you envision this being?

MR. BEARD: Right now we are talking, we think, five to six inches.

MR. MICHELSON: Just for us?

MR. CATTON: You know what might be better is to send it directly, because by the time it is resent out of here, it is the end of the week.

MR. BEARD: What I was going to say was, we will send one copy to Med, we will send a full copy to Mr. Michelson, and in the copy we send to Med, we will try and identify particular sections we feel respond to any other individual ACRS members' particular concerns.

MR. MICHELSON: Well, other members may wish to see the entire package, I wouldn't want to exclude just myself. Does anybody else want to see the entire package?

MR. WILKINS: Six inches is not 6,000, but I am tempted to say six feet.

MR. MICHELSON: It is still a lot pages, but does anybody else wish to see the entire document?

[No response.]

MR. MICHELSON: I will do the best I can to look at it and see if there are any obvious holes in it. I will do the best I can. Now each individual, though, will receive copies of that portion that they dealt with.

MR. WILKINS: From whom, not from him?

MR. MICHELSON: I thought you said you would package it up for individual members.

MR. WILKINS: I don't know how he can do that.

MR. CARROLL: He would indicate what sections they think individual people have an interest in.

MR. MICHELSON: They kind of know what Ivan has been pursuing, and they kind of know other members.

MR. WILKINS: Let me just ask him directly, are you comfortable with that or not?

MR. BEARD: What I think I was indicating we are doing is, in the package that we send Medhat, we are going to identify those parts of the package that we think go to various individual members to address their specific concerns.

MR. MICHELSON: And Medhat will see to it that it appears to be about right and send it out. That will be a delay.

MR. WILKINS: What Carl was suggesting was that instead of marking them and sending to Medhat, you mark them and send them to the members. If you err conservatively, that is okay.

MR. CARROLL: Most of the members are not even going to be home until the following week, the 21st.

MR. WILKINS: That's all right, it won't get there until the 21st.

MR. MICHELSON: That is about what he is talking about.

MR. WILKINS: That is what he is talking about, yes.

MR. MICHELSON: Why doesn't each member just get the five inches of material and do with it as he sees fit.

MR. KRESS: But it would be nice to have that marked on it.

MR. MICHELSON: You are just asking him to do your work for you. They don't know how to do it because they are really not real well acquainted with your exact interest.

MR. CARROLL: I don't want all that paper, Carl, in fact I don't want any of it.

MR. MICHELSON: Whatever the committee wants, let us get it on the record right now. What does each member want, somebody else to decide what they should see, is that what you want?

MR. CARROLL: If that someone else is going to be GE or it is going to be Med.

MR. MICHELSON: Let me suggest this, GE is going to mark it up as they think. Let's send those packages out directly to the member, and then let Medhat try to verify if there is something else that maybe a member should have seen and GE didn't identify.

MR. CATTON: When in doubt, they can call Med on the phone.

MR. MICHELSON: I think that would be a little more comfortable.

MR. SEALE: But I assume that Med will get a complete set.

MR. WILKINS: He will get a complete set, of course, yes.

MR. MICHELSON: I will get a complete set, and Med has one.

MR. WILKINS: You understand that is not quite the same as what you said?

MR. BEARD: That is not quite what I said, but I will agree to do that.

MR. WILKINS: You can agree to that, all right.

MR. MICHELSON: It is not additional work because he is going to do it anyway.

MR. WILKINS: It is a little bit of additional work, but I think it is clerical work.

MR. MICHELSON: It is not on his part at all, a little additional expense to mail.

MR. WILKINS: That is what I would call clerical work.

MR. MICHELSON: At this stage of the game cost is nothing.

MR. WILKINS: GE is not going to have to skip into the den on account of it.

MR. BEARD: I trust Medhat has FEDEX addresses for all the members.

MR. WILKINS: Med certainly does, yes.

MR. MICHELSON: I think that is a reasonable way of getting it.

MR. WILKINS: That sounds pretty good.

MR. MICHELSON: The committee should keep in mind that they will not get Amendment 34. That means you will not see where things have been changed that do not deal directly with issues that the ACRS brought up. This, of course, puts you in the position of writing off on a project without seeing all the changes.

MR. CARROLL: Which is what the ACRS has traditionally done in the past.

MR. MICHELSON: We have no tradition for this kind of project. On the operating reactors, yes. We did it two years before they ever started the plant up, and they made dozens of changes thereafter, and we issued amendments forever thereafter, but this is a different issue.

MR. CARROLL: The reason we did is because we have some confidence that the NRC regulatory staff is competent to look after our efforts.

MR. MICHELSON: The staff has no control. Once that FDA goes out, the staff has lost their control under Part 52. This is the first project under Part 52.

MR. CARROLL: You are jumping ahead. I am simply saying that the point of --

MR. MICHELSON: What is going to happen next. I hope we are going to --

MR. CARROLL: -- at the point of FDA or up to the point of FDA, I am willing to cut some slack for the NRC staff, if they are going to do the right thing.

MR. MICHELSON: We are talking about one month.

MR. CARROLL: Yes.

MR. MICHELSON: Now you are going to be willing to turn over to the staff whatever changes were made, you don't need to see them. I mean this is on the record now, I want to make sure we are altogether.

MR. CARROLL: Which is what we have traditionally done.

MR. MICHELSON: We have not traditionally done anything. There is no tradition for this. This is a new rule. Part 52 was never before there.

MR. WILKINS: Just change your language to, this is what we have done in the past on previous applications for operating licenses.

MR. MICHELSON: But this is neither a operating license, and it is under a whole new Part. It is under a whole new set of rules.

MR. WILKINS: But the letter that we sent out then needs to have some language which reflects that fact.

MR. CARROLL: It already does, as a matter of fact.

MR. BEARD: Mr. Chairman, I would like to make one other offer beyond what we have indicated, we are also willing for John Power and/or myself, if Mr. Michelson has other questions that need specific attention, we will fly to wherever we need to to bring the supporting material.

MR. WILKINS: I would think that telephone communications would be --

MR. MICHELSON: Telephones work great.

MR. WILKINS: FEDEX or overnight mail, or something will work.

MR. MICHELSON: I think this is invitational, and it should apply to all the members, of course. I am just one member in this case. It is the committee's report.

MR. WILKINS: In that connection, it would be useful if you would, when you send this material out, give your phone number and your fax number. I would hate to fight my way through the General Electric to find any given employee.

MR. BEARD: You will have a San Jose contact and a contact for me back here, and Med knows how to get a hold of both of us.

MR. CATTON: When are you planning to have the memo on the street?

MR. BEARD: To address Dr. Catton's question, yes, we are still looking to put Amendment 34 on the street March 31st.

MR. CATTON: All 6,000 pages.

MR. BEARD: All 6,000 pages.

MR. MICHELSON: We will get a copy on March 31st is that what you are saying?

MR. BEARD: I believe we are committing to shipping it out of San Jose on the 31st.

MR. WILKINS: So you may get it on the second or third of April.

MR. MICHELSON: It is not timely to look at.

MR. POSLUSNY: This is Chet Poslusny from the staff, just verifying that we will get a copy as well, Mr. Beard indicated, and we will put that on the docket.

In addition, the verification we will do will be not technical acceptability. We will verify the changes as in the markup exist in Amendment 34.

MR. MICHELSON: It should be understood that not all problems that were to be fixed appear in our letter, only the more important ones, and some of the others are even quite important but I am absolutely sure they are going to fix them, but I will not know until I see it, and that will be after we have issued our report.

MR. WILKINS: But all of them are listed or identified in this thick package that we got from GE yesterday.

MR. MICHELSON: I know what a checkmark means.

MR. WILKINS: At least the items are listed.

MR. MICHELSON: Yes, because they are very general. I think all the issues are buried in that 50 pages, sure.

MR. LINDBLAD: Mr. Chairman, while I am not one of the major players, I would like Mr. Beard to know that the 21st would be just fine, but I disappear on the evening of the 22nd for two weeks, so unless I see you in Balboa, Panama.

MR. WILKINS: I did hear him offer to fly.

MR. DAVIS: I think Mr. Lindblad was suggesting that he doesn't want to receive it before he leaves, so that he doesn't have to look at it.

MR. WILKINS: This is almost a volunteer committee, and people do go on vacations, and they do have other business to attend to, so we will all do the best we can.

MR. LINDBLAD: I have an outside stateroom with an open porthole, so I can dispose of the material as I go along.

MR. LEWIS: So you are not going to go ashore there?

MR. CARROLL: Not if the Coast Guard gets a hold of you, you can't.

MR. WILKINS: The Coast Guard, I am kind of unhappy about that, as a matter of fact.

Is there anything further on this topic, gentlemen? I think that GE has moved a long way to address some of the concerns that we expressed yesterday.

MR. CATTON: And it is impressive the lengths that they are about to go to to help us.

MR. WILKINS: Yes. I am always reluctant to say thank you until I really see it, but a tentative thank you.

Do we have anything further on this issue on the record?

MR. MICHELSON: Well, I might as well put the rest. We have one more piece. The staff gave us yesterday their revisions to the Safety Evaluation Report. Medhat is handing you a new one. Please dispose of the old one. I understand there are some changes, not to get them mixed up. The one he is handing out now is the only one to be used, if I understand it.

MR. CARROLL: This is the thing from Crutchfield

Larkins dated the 9th?

MR. MICHELSON: They will all be dated the same day and everything. I immediately put little Xs on it so that I didn't get any chance of mixing them.

MR. WILKINS: Dump the punched one.

MR. DAVIS: Are we off the record now?

MR. WILKINS: We will be in just a second.

Let me ask, is there anything further we need to discuss on this matter?

[No response.]

MR. WILKINS: Then I think we will move to the next agenda item, and we can thank our reporter.

[Whereupon, at 4:50 p.m., the meeting was adjourned.]

REPORTER'S CERTIFICATE

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

NAME OF PROCEEDING: 407th ACRS Meeting

DOCKET NUMBER:

PLACE OF PROCEEDING: Bethesda, MD

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

Marlene Estep

Official Reporter
Ann Riley & Associates, Ltd.

EVALUATION OF ISSUES FROM

THE MULTIPLE SYSTEMS RESPONSE PROGRAM

RES STAFF PRESENTATION

TO

THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

MARCH 11, 1994

BY

CHARLES Z. SERPAN & T.Y. CHANG, ENGINEERING ISSUES BRANCH
DIVISION OF SAFETY ISSUE RESOLUTION
OFFICE OF NUCLEAR REGULATORY RESEARCH

OVERVIEW OF

MULTIPLE SYSTEMS RESPONSE PROGRAM

- MSRP REVIEWED EXISTING AND ONGOING NRC PROGRAMS TO AVOID DUPLICATION OF EFFORTS, AND CONSIDERED CREATING NEW GIs IF NEEDED
- MSRP DOES NOT MONITOR NRC ONGOING PROGRAM SCHEDULES
- MSRP IS A ROAD MAP. ACRS WILL BE INVOLVED IN EACH OF THESE PROGRAMS WITH THE RESPONSIBLE BRANCHES
- PRESENTATION WILL BE FOCUSED ON THE FIRST 12 ISSUES. REMAINING ISSUES ARE RELATED TO IPE/IPEEE PROGRAMS
- THE STAFF MSRP REPORT, "EVALUATION OF POTENTIAL SAFETY ISSUES RESULTING FROM THE MSRP," WILL BE UPDATED WITH COMMENTS FROM VARIOUS SOURCES BEFORE FINAL ISSUANCE

BACKGROUND

- o MSRP CONDUCTED BY ORNL RESULTED IN NUREG/CR-5420 (10/89)
  - IDENTIFIED ACRS CONCERNS ON SOME POTENTIAL SAFETY ISSUES NOT BEING ADDRESSED BY GIs, USIs AND TMI TASK FORCE FINDINGS
  - GROUPED CONCERNS INTO 21 POTENTIAL SAFETY ISSUES
- o PRELIMINARY BRIEFING TO ACRS ON 2/12/93
- o THIS BRIEFING PRESENTS FINAL STAFF EVALUATION OF THE 21 POTENTIAL SAFETY ISSUES
  - NO NEW GIs
  - 3 ISSUES SHOULD BE DROPPED
  - REMAINING ISSUES SHOULD BE INCLUDED WITHIN SCOPE OF EXISTING GIs OR OTHER ONGOING NRC OR INDUSTRY PROGRAMS

STAFF EVALUATION OF 21 POTENTIAL SAFETY ISSUES

7.4.1 COMMON CAUSE FAILURES RELATED TO HUMAN ERRORS

CONCERNS

- CCFs FROM HUMAN ERRORS (ERRORS IN OPERATION, COMPONENT MANUFACTURING, INSTALLATION, MAINTENANCE, OR TESTING) CAN CAUSE UNPLANNED EVENTS AND/OR AFFECT REDUNDANT TRAINS

CONCLUSION

- EXISTING PRAs ADDRESS ERROR OF OMISSION BUT NOT THOSE OF COMMISSION. COMMISSION ERRORS REMAIN A PRIORITY RESEARCH ITEM UNDER STUDY

- PRESENT STAFF APPROACH IS TO APPLY HUMAN ENGINEERING PRINCIPLES TO REDUCE HUMAN ERROR THROUGH REGULATORY REVIEW, INSPECTION, RESEARCH AND DEVELOPMENT OF REGULATORY GUIDANCE

- IPE COVERS CCFs FROM ERRORS OF OMISSION IN OPERATION, MAINTENANCE, OR TESTING

- ONGOING PROGRAMS ADEQUATE TO ADDRESS THIS ISSUE

7.4.2 NON-SAFETY-RELATED CONTROL SYSTEM/SAFETY-RELATED PROTECTION SYSTEM DEPENDENCIES

CONCERNS

- FAILURES OF NON-SAFETY-RELATED CONTROL SYSTEMS MAY ADVERSELY IMPACT SAFETY-RELATED PROTECTION SYSTEMS DUE TO POTENTIALLY UNRECOGNIZED DEPENDENCIES BETWEEN THEM
- PLANT-SPECIFIC IMPLEMENTATION OF REGULATIONS FOR SEPARATION & INDEPENDENCE OF CONTROL AND PROTECTION SYSTEMS MAY BE INADEQUATE

CONCLUSION

- RESULTS OF STUDY FROM USI A-17 CONCLUDED THAT A FULL SCOPE PLANT SEARCH OF SYSTEMS INTERACTIONS IS COSTLY AND INEFFECTIVE
- IPE PROCESS SHOULD IDENTIFY PLANT-SPECIFIC POTENTIAL SOURCES OF VULNERABILITIES
- CONTINUED NOTICES, LETTERS, AND BULLETINS ADDRESSING IDENTIFIED PROBLEMS FROM OPERATIONAL EXPERIENCE SHOULD BE ENOUGH

7.4.3 FAILURE MODES OF DIGITAL COMPUTER CONTROL SYSTEMS

CONCERNS

- COMPUTERIZED CONTROL SYSTEMS PRESENTS THE POTENTIAL FOR COMPLEX OR UNEXPECTED FAILURE MODES THAT MIGHT IMPACT PROTECTION SYSTEMS

- THE USE OF DIGITAL CONTROL SYSTEMS FOR SAFETY-RELATED PURPOSES MAY RAISE NEW QUESTIONS

STATUS

- POTENTIAL FAILURE MODES/INTERACTIONS IN COMPUTER SYSTEMS ARE CONSIDERED IN NRR REVIEWS OF DIGITAL SYSTEMS IN OPERATING PLANTS AND ADVANCED REACTORS

- CURRENT RESEARCH AND DIGITAL SYSTEM CRITERIA DEVELOPMENT IS ADDRESSING THIS ISSUE. THIS ISSUE WILL BE PART OF THE NAS/NAE STUDY TITLED "STUDY AND WORKSHOP ON APPLICATION OF DIGITAL INSTRUMENTATION AND CONTROL SYSTEMS TO NUCLEAR POWER PLANTS"

- NO NEW ACTIVITY NEEDED

7.4.4 SPECIFIC SCENARIOS NOT CONSIDERED IN USI A-47

CONCERNS

- TWO SCENARIOS NOT EVALUATED DURING REVIEW OF USI A-47
  - SCRAM WITHOUT A TURBINE TRIP (SWATT) RESULTING IN OVERCOOLING OF PRIMARY SYSTEM AND RECRITICALITY
  - STEAM GENERATOR OVERFILL (RESULTING FROM SGTR) LEADING TO AN MSLB AND MORE SGTRs, THAT WOULD INVOLVE THE BLOWDOWN OF MORE THAN ONE STEAM GENERATOR

CONCLUSION

- FIRST SCENARIO WAS ADDRESSED IN GI-144, "SCRAM WITHOUT A TURBINE/GENERATOR TRIP" (EVALUATED AS A LOW PRIORITY)

- SECOND SCENARIO WAS ADDRESSED IN GI-135, "STEAM GENERATOR AND STEAM LINE OVERFILL" (RESOLVED IN 1991)

- TWO CONCERNS HAVE BEEN EVALUATED THROUGH THE GI PROCESS, AND RESOLVED WITH NO ACTION NEEDED

7.4.5 EFFECTS OF DEGRADATION OF HVAC EQUIPMENT ON CONTROL AND PROTECTION SYSTEMS

CONCERNS

- SAFETY-RELATED EQUIPMENT COULD BE IMPACTED DIRECTLY BY LOSS OR DEGRADATION OF HVAC SYSTEMS, OR INDIRECTLY THROUGH INTERACTIONS WITH NON-SAFETY-RELATED COMPONENTS

CONCLUSION

- DIRECT IMPACT OF LOSS OF HVAC SYSTEMS ON SAFETY-RELATED SYSTEMS AND COMPONENTS WAS ADDRESSED IN GI-143, "AVAILABILITY OF CHILLED WATER SYSTEMS AND ROOM COOLING"

- ACRS REVIEWED RESOLUTION OF GI-143 IN AUGUST 1993. RESOLUTION INDICATED THAT PROPOSED RESOLUTION DOES NOT PASS COST/BENEFIT TEST

- NO FURTHER ACTION NEEDED

7.4.6 FAILURE MODES RESULTING FROM DEGRADED ELECTRIC POWER SOURCES

CONCERNS

- USI A-47 ADDRESSED EFFECTS ON SAFETY RELATED EQUIPMENT DUE TO SUDDEN COMPLETE LOSS OF ELECTRICAL POWER SOURCES BUT NOT DEGRADATION

CONCLUSION

- GI A-35, "ADEQUACY OF OFFSITE POWER SYSTEM," DID ADDRESS IMPACT ON SAFETY-RELATED EQUIPMENT TO SUSTAINED DEGRADED VOLTAGE FROM OFFSITE POWER SOURCES

- ONGOING NRC AGING RESEARCH INCLUDES A PROGRAM ON THE 1E POWER SYSTEMS (AC,DC & VITAL I&C SYSTEMS)

  - INVESTIGATES (1) AGING-RELATED DEGRADATION MECHANISMS & FAILURE MODES; (2) INSPECTION, SURVEILLANCE, AND MONITORING METHODS (IS&MM) ON 1E POWER SYSTEMS
  - EXPLORES APPLICABILITY OF ADVANCED IS&MM TO SUPPLEMENT & ENHANCE CURRENT PRACTICES

- NO NEW ACTIVITY NEEDED

7.4.7 FAILURE MODES RESULTING FROM DEGRADED COMPRESSED AIR SYSTEMS

CONCERNS

- DEGRADATION OF COMPRESSED AIR SYSTEMS HAS THE POTENTIAL TO AFFECT MULTIPLE TRAINS OF SAFETY-RELATED EQUIPMENT
- USI A-47 ADDRESSED EFFECTS OF SUDDEN COMPLETE LOSS OF AIR PRESSURE, BUT NOT OF DEGRADATION OF AIR SYSTEMS

CONCLUSION

- RESOLUTION OF GI-43, "AIR SYSTEM RELIABILITY," RESULTED IN ISSUANCE OF GL 88-14
- ISSUANCE OF GL 88-14 RESULTED IN (1) MAJOR UTILITY EFFORTS WHERE AIR SYSTEM PROBLEMS WERE FOUND AND CORRECTED, & (2) AGGRESSIVE INDUSTRY ACTIVITIES TO IMPROVE RELIABILITY OF AIR-OPERATED EQUIPMENT
- ALTHOUGH SLOW BLEEDDOWN TEST AS ORIGINALLY RECOMMENDED BY AEOD IS DESIRABLE, STAFF BELIEVES THAT CONTINUING MONITORING LICENSEE ACTIONS UNDER GL 88-14 WILL BE SUFFICIENT FOR NOW

7.4.8 POTENTIAL EFFECTS OF UNTIMELY COMPONENT OPERATION

CONCERNS

- EFFECTS OF COMPONENTS CHANGING STATE OR ACTUATING IN AN UNANTICIPATED SEQUENCE FROM SPURIOUS SIGNALS CAN POTENTIALLY CAUSE DAMAGE TO SAFETY-RELATED EQUIPMENT

CONCLUSION

- RECENT STAFF EVALUATION OF OPERATIONAL EVENTS (1984-1991) IN ACCIDENT SEQUENCE PRECURSORS PROGRAM INDICATED

  - MAJOR CAUSE OF UNTIMELY EQUIPMENT OPERATION IS HUMAN ERROR
  - EFFECTS IN MOST CASES ARE REACTOR, GENERATOR, OR TURBINE TRIPS
  - REMAINING EVENTS INVOLVED SEQUENCES WITHIN THE PLANT DESIGN BASIS OR WITHIN SCOPE OF EXISTING GIs

- STAFF BELIEVES THIS ISSUE HAS BEEN ADEQUATELY ADDRESSED BY EXISTING GIs AND OTHER NRC PROGRAMS. APPLICATION OF HUMAN ENGINEERING PRINCIPLES (ISSUE 7.4.1) SHOULD REDUCE HUMAN ERROR CONTRIBUTION

7.4.9 PROPAGATION OF ENVIRONMENTS ASSOCIATED WITH DBEs

CONCERNS

- IF HARSH ENVIRONMENT PROPAGATES BY SOME UNKNOWN OR UNRECOGNIZED PATH FROM ONE ZONE INTO ANOTHER ZONE, EQUIPMENT REQUIRED FOR SAFE SHUTDOWN IN THIS NEW ZONE MAY NOT BE QUALIFIED FOR SUCH HARSH ENVIRONMENT

CONCLUSION

- 10 CFR 50.49 REQUIRES DBE ENVIRONMENTAL CONDITIONS BE SPECIFIED IN THE QUALIFICATION FILE AT LOCATIONS WHERE EQUIPMENT IMPORTANT TO SAFETY MUST PERFORM, & THE EQUIPMENT IN TURN BE QUALIFIED TO THESE DBE CONDITIONS

- STAFF CONSIDERS THIS ISSUE TO BE AN ISSUE OF COMPLIANCE FOR 10 CFR 50.49 AND SHOULD BE TREATED AS SUCH INSTEAD OF AS AN GI

7.4.10 EVALUATION OF HEAT, SMOKE AND WATER PROPAGATION EFFECTS RESULTING FROM FIRES

CONCERNS

- FIRE CAN POTENTIALLY DAMAGE ONE TRAIN OF EQUIPMENT IN ONE FIRE ZONE AND DAMAGE A REDUNDANT TRAIN IN ANOTHER FIRE ZONE DUE TO PROPAGATION OF HEAT, SMOKE AND WATER

CONCLUSION

- WATER PROPAGATION EFFECTS RESULTING FROM FIRE WAS PARTIALLY ADDRESSED IN THE RESOLUTION OF GI-57, "EFFECTS OF FIRE PROTECTION SYSTEM ACTUATION ON SAFETY-RELATED EQUIPMENT"

- ONGOING RES PROGRAM LOOKS INTO EFFECTS OF SMOKE (TOGETHER WITH SYNERGISTIC EFFECTS FROM TEMPERATURE, MOISTURE/HUMIDITY, ETC.) ON DIGITAL I&C SYSTEMS

- RES PLANS TO WORK WITH NRR TO ASSURE THIS ISSUE IS CONSIDERED IN THE ONGOING NRR FIRE PROTECTION TASK ACTION PLAN (FP-TAP)

7.4.11 SYNERGISTIC EFFECTS OF HARSH ENVIRONMENTAL CONDITIONS

CONCERNS

- A LACK OF REGULATORY GUIDANCE FOR ANALYZING SYNERGISTIC EFFECTS MAKES IT DIFFICULT TO ASSESS WHAT LICENSEES HAVE DONE IN THIS AREA, AND THEREFORE SOME EQUIPMENT IMPORTANT TO SAFETY MAY NOT BE ADEQUATELY QUALIFIED FOR THE ACTUAL ENVIRONMENTS

CONCLUSION

- RES IS WORKING WITH NRR ON THE PLANNED ACTIONS OF EQ 10 CFR 50.49 TASK ACTION PLAN (EQ-TAP) WHERE THE ADEQUACY OF EXISTING EQ STANDARDS AND REGULATIONS FOR OPERATING REACTORS IS GOING TO BE EVALUATED

- RES PROGRAM PLAN WILL INCLUDE SYNERGISTIC EFFECTS

- THE CONCERNS OF THIS ISSUE WILL BE INCLUDED IN THE EQ-TAP

7.4.12 ENVIRONMENTAL QUALIFICATION OF SEALS, GASKETS, PACKING, AND LUBRICATING FLUIDS ASSOCIATED WITH MECHANICAL EQUIPMENT

CONCERNS

- SUBCOMPONENTS (SEALS, GASKETS, PACKING MATERIALS, LUB. FLUIDS) IN SOME MECHANICAL EQUIPMENT (ME) MAY NOT BE ADEQUATELY QUALIFIED TO NORMAL HARSH ENVIRONMENTS DUE TO LACK OF CONCERTED INDUSTRY EQ PROGRAM ON ME & NRC REVIEW

CONCLUSION

- EXISTING & ONGOING GIs ADDRESS OPERABILITY/RELIABILITY OF PORV, MOV AND OTHER POWER OPERATED VALVES

- PERIODIC IN-SERVICE TESTING (ASME OM CODE) ON PUMPS/VALVES, AND IMPLEMENTATION OF MAINTENANCE RULE SHOULD HELP TO IDENTIFY AND REPLACE DEGRADED SUBCOMPONENTS

- RELIABILITY-CENTERED MAINTENANCE PROGRAM (RCM) AND THE USERS GROUP SPONSORED BY EPRI SHOULD HELP TO IDENTIFY DEGRADED SUBCOMPONENTS FOR REPLACEMENT

7.4.12 (CONTINUE)

- FOR FUTURE PLANTS AND REPLACEMENTS, FORTHCOMING ASME STANDARD ON EQ OF ME (QME) SHOULD ADDRESS THIS CONCERN
- NO FURTHER ACTION NEEDED

7.4.13 EFFECTS OF FIRE SUPPRESSION ACTUATION ON NON-SAFETY-RELATED AND SAFETY-RELATED EQUIPMENT

CONCERNS

- FIRE SUPPRESSION SYSTEM ACTUATION EVENTS CAN HAVE AN ADVERSE EFFECT ON SAFETY-RELATED COMPONENTS EITHER THROUGH DIRECT CONTACT WITH SUPPRESSION AGENT OR THROUGH INDIRECT INTERACTIONS WITH NON-SAFETY-RELATED COMPONENTS

CONCLUSION

- THIS CONCERN WAS ADDRESSED IN GI-57

- THIS CONCERN WILL BE CONSIDERED BY LICENSEES DURING THEIR IMPLEMENTATION OF THE IPEEE PROCESS ON A PLANT-SPECIFIC BASIS

7.4.14 EFFECTS OF FLOODING AND/OR MOISTURE INTRUSION ON NON-SAFETY RELATED AND SAFETY-RELATED EQUIPMENT

CONCERNS

- FLOODING AND/OR MOISTURE INTRUSION COULD DIRECTLY OR INDIRECTLY AFFECT SAFETY-RELATED EQUIPMENT

CONCLUSION

- IPE SUBMITTAL GUIDANCE DOES INCLUDE AREAS SUCH AS MOISTURE INTRUSION AND INTERNAL FLOODING

- IPEEE PROCESS WILL ADDRESS EXTERNAL FLOODING AND/OR MOISTURE INTRUSION RESULTING FROM EXTERNAL EVENTS

- IPE/IPEEE PROCESS SHOULD DETECT PLANT-SPECIFIC VULNERABILITIES FOR THIS ISSUE

7.4.15 SEISMICALLY-INDUCED SPATIAL AND FUNCTIONAL INTERACTIONS

CONCERNS

- SEISMIC EVENTS HAVE THE POTENTIAL TO CAUSE MULTIPLE FAILURES OF SAFETY-RELATED SYSTEMS THROUGH SPATIAL AND/OR FUNCTIONAL INTERACTIONS

CONCLUSION

- THE LICENSEES' EVALUATION OF THEIR PLANTS FOR VULNERABILITIES TO SEISMIC EVENTS AS PART OF THE IPEEE IS SUFFICIENT TO ADDRESS THIS CONCERN

7.4.16 SEISMICALLY-INDUCED FIRES

CONCERNS

- SEISMICALLY-INDUCED FIRES HAVE THE POTENTIAL TO CAUSE MULTIPLE FAILURES OF SAFETY-RELATED SYSTEMS

CONCLUSION

- THIS CONCERN WAS CONSIDERED IN THE RESOLUTION OF GI-57

- THIS CONCERN WILL BE ADDRESSED BY LICENSEES DURING THEIR IMPLEMENTATION OF THE IPEEE PROCESS ON A PLANT-SPECIFIC BASIS

7.4.17 SEISMICALLY-INDUCED FIRE SUPPRESSION SYSTEM ACTUATIONS

CONCERNS

- SEISMIC EVENTS CAN POTENTIALLY CAUSE MULTIPLE FIRE SUPPRESSION SYSTEM ACTUATIONS, THEREBY RESULT IN FAILURES OF REDUNDANT TRAINS OF SAFETY-RELATED SYSTEMS

CONCLUSION

- THIS CONCERN WAS CONSIDERED IN THE RESOLUTION OF GI-57
- THIS CONCERN WILL BE ADDRESSED BY LICENSEES DURING THEIR IMPLEMENTATION OF THE IPEEE PROCESS ON A PLANT-SPECIFIC BASIS

7.4.18 SEISMICALLY-INDUCED FLOODING

CONCERNS

- SEISMICALLY-INDUCED FLOODING EVENTS CAN POTENTIALLY CAUSE MULTIPLE FAILURES OF SAFETY-RELATED SYSTEMS

CONCLUSION

- THE LICENSEES' EVALUATION OF THEIR PLANTS FOR VULNERABILITIES TO SEISMIC EVENTS AS PART OF THE IPEEE IS SUFFICIENT TO ADDRESS THIS CONCERN

7.4.19 SEISMICALLY-INDUCED RELAY CHATTER

CONCERNS

- CONTACT CHATTER OF RELAYS NOT REQUIRED TO OPERATE DURING SEISMIC EVENTS MAY PRODUCE UNANALYZED FAULTING MODES THAT MAY IMPACT THE OPERABILITY OF EQUIPMENT REQUIRED TO MITIGATE THE EVENT

CONCLUSION

- THE LICENSEES' EVALUATION OF THEIR PLANTS FOR VULNERABILITIES TO SEISMIC EVENTS AS PART OF THE IPEEE IS SUFFICIENT TO ADDRESS THIS CONCERN

7.4.20 EVALUATION OF EARTHQUAKE MAGNITUDES GREATER THAN THE SAFE SHUTDOWN EARTHQUAKE

CONCERNS

- SEISMIC MARGINS FOR EARTHQUAKE LARGER THAN PLANT SSE MAY NOT HAVE BEEN INCLUDED IN THE DESIGN OF SOME SAFETY-RELATED EQUIPMENT

CONCLUSION

- THE LICENSEES' EVALUATION OF THEIR PLANTS FOR VULNERABILITIES TO SEISMIC EVENTS AS PART OF THE IPEEE IS SUFFICIENT TO ADDRESS THIS CONCERN

7.4.21 EFFECTS OF HYDROGEN LINE RUPTURES

CONCERNS

- THE POTENTIAL FOR HYDROGEN LINE RUPTURES COULD RESULT IN FIRES AND/OR EXPLOSIONS DAMAGING VITAL SAFETY-RELATED SYSTEMS OF THE PLANT

CONCLUSION

- GL 93-06 WAS ISSUED TO ALL LICENSEES AS RESULT OF RESOLUTION OF GI-106, "PIPING AND USE OF HIGHLY COMBUSTIBLE GASES IN VITAL AREAS"

  - IT INCLUDES NEW INFORMATION DEVELOPED UNDER GI-106 WHICH IS EXPECTED TO BE USEFUL TO LICENSEES IN PERFORMING THEIR IPEEEs

- NO FURTHER ACTION NEEDED

NRC STAFF PRESENTATION TO THE ACRS

SUBJECT: FERMI 2 CATASTROPHIC TURBINE-GENERATOR FAILURE

DATE: MARCH 11, 1994

PRESENTER: RONALD N. GARDNER, CHIEF
PLANT SYSTEMS SECTION
ENGINEERING BRANCH
DIVISION OF REACTOR SAFETY
REGION III

TELEPHONE NO.: (708) 829-9751

PROBLEM

1. CATASTROPHIC TURBINE FAILURE
2. HYDROGEN/LUBE OIL FIRE
3. RADWASTE BASEMENT FLOODING
4. REACTOR COOLANT SYSTEM (RCS) CHEMISTRY

CAUSE

1. TURBINE

   A. LICENSEE INVESTIGATING

   B. POTENTIAL HIGH CYCLE FATIGUE

2. FIRE

   A. HYDROGEN LEAKAGE

   B. SIGNIFICANT GENERATOR SHAFT/INTERNALS DISPLACEMENT

3. FLOODING

   A. FIRE PROTECTION SYSTEM ACTUATION/DAMAGE

   B. GENERAL SERVICE WATER PIPE TO HYDROGEN COOLERS

   C. TURBINE BUILDING CLOSED COOLING WATER LINE

   D. LUBE OIL LINE

4. CHEMISTRY

   A. CONDENSER TUBES RUPTURED

   B. HOTWELL REJECT TO CONDENSATE STORAGE TANK

   C. STANDBY FEEDWATER SUCTION FROM CONDENSATE STORAGE TANK

SAFETY SIGNIFICANCE

1. SAFETY RELATED/SAFE SHUTDOWN PERFORMANCE NOT AFFECTED

2. GASEOUS RELEASES WITHIN NORMAL RANGE

3. LIQUID RELEASES CONTAINED NO DETECTABLE CONTAMINATION

NRC ACTION

1. SENIOR RESIDENT INSPECTOR RESPONDED IMMEDIATELY

2. AUGMENTED INSPECTION TEAM (AIT)

3. EXPANDED AIT TO PROVIDE WATER MANAGEMENT OVERSIGHT

DISCUSSION

* DECEMBER 25, 1993 - TURBINE FAILURE
* REACTOR SCRAMMED - ALL SAFETY SYSTEMS FUNCTIONED AS EXPECTED
* MAIN STEAM ISOLATION VALVES CLOSED
* REACTOR PRESSURE CONTROLLED VIA SAFETY RELIEF VALVES AND REACTOR CORE ISOLATION COOLING (RCIC)
* OPERATOR ERROR CAUSED DELAY IN PLACING RCIC IN SERVICE
* ALERT DECLARED
* LOCAL FIRE DEPARTMENT SUMMONED TO SITE
* APPROXIMATELY 500,000 GALLONS OF WATER AND 17,000 OF OIL RELEASED TO TURBINE BUILDING FLOORS
* WATER AND OIL OVERFLOWED TO RADWASTE BASEMENT
* RCS CONDUCTIVITY INCREASED DUE TO SEVERED CONDENSER TUBES

DISCUSSION (CONT'D)

* OPERATORS SLOW TO RECOGNIZE SIGNIFICANCE OF HIGH HOTWELL LEVEL

* WHEN ATTEMPTING TO PLACE DIVISION II SHUTDOWN COOLING IN SERVICE, THE "B" RECIRCULATION PUMP DISCHARGE VALVE WOULD NOT CLOSE.

* RESIDUAL HEAT REMOVAL (RHR) WARMUP VALVE FAILED TO CLOSE WHEN PLANT WAS BEING PLACED IN RHR SHUTDOWN COOLING MODE

* ON DECEMBER 26, 1993, THE PLANT ENTERED COLD SHUTDOWN

INSPECTION RESULTS

TURBINE FAILURE

* NO INDICATION OF PENDING TURBINE-GENERATOR FAILURE

* ROOT CAUSE BEING INVESTIGATED BY LICENSEE

* NO INDICATION FAILURE WAS DUE TO TURBINE OVERSPEED OR ELECTRICAL GRID DISTURBANCES

* FERMI PRECURSOR EVENTS:

  SEPTEMBER 1989 - REFUELING OUTAGE (RFO) 1

  * FAILED BLADES FOUND IN 5TH STAGE OF LOW PRESSURE (LP) 2

  * ALL LP TURBINE EIGHTH STAGE BLADES SUSTAINED EXCESSIVE WEAR OF LACING RODS AND LACING HOLES DUE TO TIP ROCK

  DECEMBER 1990

  * FIVE STAGE 4 BLADES OF LP3 EXPERIENCED FATIGUE FAILURE

APRIL 1991 - RF02

* ALL LP TURBINE STAGE 4 BLADES REPLACED

* ALL LP 5TH STAGE BLADES REINSTALLED

* REFURBISHED EIGHTH STAGE LP1 BLADES INSTALLED IN LP2

SEPTEMBER 1992 - RF03

* BASED ON VISUAL INSPECTION, LICENSEE DID NOT REPLACE EIGHTH STAGE BLADES IN LP3

INSPECTION RESULTS

RCS CHEMISTRY

* HIGH CONDUCTIVITY
  - PRIOR 0.08 uMHOS
  - AFTER 185.0 uMHOS (MAX)

* HIGH CHLORIDES
  - PRIOR < 2 PPB
  - AFTER 10 PPM (MAX)

* CONCERNS
  1. CONTROL ROD DRIVE (CRD) SEALS
  2. REACTOR INTERNALS

* TEMPORARY MODIFICATIONS
  1. CONDENSATE RETURN TANK (CRT) TO CRD FOR CRD SEALS BACK TO CRT VIA REACTOR WATER CLEANUP (RWCU) AND PORTABLE DEMINERALIZERS
  2. RWCU TO PORTABLE DEMINERALIZERS (HIGHER FLOWS)

INSPECTION RESULTS

FIRE PROTECTION SYSTEM

* AUTOMATIC SUPPRESSION AND FIRE ALARM SYSTEMS OPERATED AS DESIGNED

* FULL FIRE BRIGADE RESPONDED AS A TEAM APPROXIMATELY 37 MINUTES AFTER THE EVENT

* COMMUNICATIONS PROBLEMS CAUSED DELAYS IN ASSESSING FIRE'S EXTENT

PLANT FLOODING

* NO ABNORMAL PROCEDURE FOR TURBINE BUILDING FLOODING

* DIFFICULTY IN SECURING SYSTEMS CAUSING FLOODING

INSPECTION RESULTS

WATER MANAGEMENT

1. RADWASTE BUILDING

   * 500,000 GALLONS OF WATER AND 17,000 GALLONS OF OIL FLOODED RADWASTE BUILDING BASEMENT

   * WATER BECAME CONTAMINATED AFTER MIXING WITH CONTENTS OF TANKS AND SUMPS

   * NORMAL RADWASTE PROCESSING EQUIPMENT INOPERABLE

   * PRESENT DESIGN INADEQUATE TO PREVENT FUTURE FLOODING

   * TEMPORARY MODIFICATION TRANSFERRED WATER TO HOTWELL

2. REACTOR BUILDING

* CORNER ROOMS 40 FT. BELOW RADWASTE BUILDING BASEMENT

* NO TESTING OR PREVENTIVE MAINTENANCE ON CHECK VALVES DESIGNED TO PREVENT CORNER ROOM FLOODING

3. CONDENSATE STORAGE TANK

* DAMAGE TO MAIN CONDENSER RESULTED IN LAKE WATER ENTERING CONDENSER HOTWELL AND BEING PUMPED TO CONDENSATE STORAGE TANK

* TEMPORARY MODIFICATION INSTALLED TEMPORARY DEMINERALIZER SYSTEM TO RECIRCULATE AND TREAT WATER PRIOR TO DISCHARGE

LOSS OF OFFSITE POWER WITH COMPLICATIONS AT

MCGUIRE, UNIT 2

UNITED STATES NUCLEAR REGULATORY COMMISSION

MARCH 11, 1994

NRC STAFF PRESENTATION TO THE ACRS

SUBJECT:	LOSS OF OFFSITE POWER AT MCGUIRE, UNIT 2
DATE:	MARCH 11, 1994
PRESENTER:	ERIC J. BENNER
PRESENTER'S TITLE:	REACTOR SYSTEMS ENGINEER EVENTS ASSESSMENT BRANCH DIVISION OF OPERATING REACTOR SUPPORT
PRESENTER'S NRC PHONE NUMBER	(301) 504-1171

OUTLINE

SEQUENCE OF EVENTS

DECEMBER 27, 1993

22:06:31	525 kV "2B" BUS LOST DUE TO PHASE DIFFERENTIAL FAULT CAUSED BY FAILED INSULATOR. TURBINE RUNBACK FAILS TO INITIATE.
22:07:00	525 kV "2A" FEEDER LOST WHEN PCB 58 & 59 OPEN ON OVERCURRENT RESULTING IN LOSS OF OFFSITE POWER (LOOP). TURBINE GENERATOR FREQUENCY INCREASES DUE TO LOSS OF LOAD.
22:07:03	REACTOR POWER PEAKED AT 103%.
22:07:07	REACTOR TRIP ON "POWER RANGE HIGH FLUX RATE."
22:07:08	BLACKOUT LOGIC INITIATES CAUSING DIESEL GENERATORS (DGs) START.
22:07:20	REACTOR COOLANT PUMPS (RCPs) TRIP ON LOSS OF POWER, NATURAL CIRCULATION ENTERED.

22:07:50	AUXILIARY FEEDWATER (AFW) PUMPS BEGIN INJECTING INTO ALL FOUR STEAM GENERATORS (SGs).
22:14:04	SAFETY INJECTION (SI) ON "PRESSURIZER LOW PRESSURE" WHEN PRESSURIZER PRESSURE FELL TO 1845 PSIG.
22:15	"B" STEAM LINE PRESSURE REACHES 775 PSIG RESULTING IN MAIN STEAM ISOLATION VALVE (MSIV) CLOSURE SIGNAL. MSIV "B" FAILS TO CLOSE. ATTEMPTS TO MANUALLY CLOSE THE VALVE UNSUCCESSFUL.
22:20	OPERATORS TRANSITION TO EP03, "STEAM LINE BREAK OUTSIDE CONTAINMENT," DUE TO STEAM HEADER PRESSURE DECREASING IN UNCONTROLLED MANNER.
22:22	UNUSUAL EVENT (UE) DECLARED DUE TO LOOP.
22:23	OPERATORS THROTTLE AFW.

22:36	OPERATORS ISOLATED AFW TO SG "B" IN ACCORDANCE WITH EP03.
22:45:49	SG "B" REACHES LO LO LEVEL SETPOINT.
22:48	REACTOR COOLANT SYSTEM (RCS) PRESSURE DECREASED USING PRESSURIZER POWER OPERATED RELIEF VALVES (PORVs) TO MAINTAIN DIFFERENTIAL PRESSURE BETWEEN RCS AND SG "B" LESS THAN 1600 PSID, PER WESTINGHOUSE GUIDELINES. [PEAK WAS 1981 PSID]
23:26	PRESSURIZER RELIEF TANK RUPTURE DISK RUPTURES DUE TO MASS ADDITION FROM CYCLING OF PORVs. STEAM RELEASE CAUSES ICE CONDENSER DOORS TO OPEN.
23:42	OFFSITE POWER BUS "2A" RESTORED.
23:45	WIDE RANGE LEVEL INDICATES SG "B" IS DRY.

DECEMBER 28, 1993

00:00	PERSONNEL INCORRECTLY JUMPER OPEN DRAIN VALVES UPSTREAM OF MSIVs.
00:32	EMERGENCY BUSES REALIGNED TO OFFSITE POWER. DGs SECURED.
01:37	RCP "A" STARTED TO RESTORE FORCED CIRCULATION.
02:00	CONTAINMENT PRESSURE PEAKS AT 0.57 PSIG.
06:22	SECOND OFFSITE POWER SOURCE ESTABLISHED.
12:55	UE TERMINATED WHEN SI LOGIC REINSTATED. SG "B" LO LO LEVEL TRIP JUMPERED TO ALLOW CLOSING OF REACTOR TRIP BREAKERS TO REINSTATE SI LOGIC.

ISSUES

1. ELECTRICAL SYSTEM DESIGN

2. MAIN STEAM ISOLATION VALVE OPERABILITY

3. PROCEDURAL ADHERENCE

4. DOCUMENT CONTROL

5. CORRECTIVE ACTIONS FROM PREVIOUS EVENT

6. PROBABILISTIC RISK ASSESSMENT INSIGHTS

1. ELECTRICAL SYSTEM DESIGN

- BUS "2B" INSULATOR FAILURE CAUSED BY DETERIORATION OF CEMENT IN INSULATOR.

- BUS "2A" LOST DUE TO FAILED TURBINE RUNBACK IN CONJUNCTION WITH INADEQUATE RELAY COORDINATION.

  - TURBINE RUNBACK FAILED DUE TO A FAILED RESISTOR ON THE DIGITAL ELECTRO-HYDRAULIC SYSTEM INPUT SLAVE CIRCUIT BOARD.

  - IN 1989, RUNBACK CIRCUIT WAS CHANGED FROM 15 SECONDS TO 3 MINUTES. AT 3 MINUTES, 51L COULD POTENTIALLY ACTUATE EVEN HAD THE RUNBACK FUNCTIONED AS DESIGNED.

  - DESIGN RELIED ON TURBINE GENERATOR RUNBACK IN THE EVENT OF A LOSS OF ONE OFFSITE LINE TO PREVENT OVERLOAD OF LINE MAIN TRANSFORMERS. INADEQUATELY COORDINATED PROTECTIVE RELAYS (BACKUP NON-DIRECTIONAL RELAY 51L) TRIPPED OTHER OFFSITE SOURCE INSTEAD OF MAIN GENERATOR OUTPUT CIRCUIT BREAKER.

2. MAIN STEAM ISOLATION VALVE OPERABILITY

- MSIV FAILURE TO CLOSE WAS CAUSED BY MECHANICAL BINDING.

  - CLEARANCE TOLERANCES BETWEEN VALVE YOKE RODS AND SPRING PLATE GUIDES ESTABLISHED AND CHECKED COLD, NOT AT NORMAL OPERATING TEMPERATURE AS RECOMMENDED BY THE VALVE VENDOR.

  - SURVEILLANCE TESTS DID NOT REQUIRE THE VALVE TO FUNCTION AT OPERATING TEMPERATURE.

3. PROCEDURAL ADHERENCE

- OPERATORS PERFORMED ACTIONS OUTSIDE EMERGENCY OPERATING PROCEDURES WITHOUT USING APPROPRIATE REFERENCES.

  - I&C PERSONNEL JUMPERED OPEN FOUR CLOSED STEAM DRAIN VALVES UPSTREAM OF THE MSIVs BELIEVING INCORRECTLY THAT THESE VALVES FAILED OPEN AND NEEDED TO BE JUMPERED SHUT.

  - VALVES HAD BEEN MODIFIED TO FAIL-CLOSE, HOWEVER OPERATORS BELIEVED THEM TO BE FAIL-OPEN AND DID NOT REFER TO DRAWINGS TO VERIFY.

- REPORTING PROCEDURE WAS NOT IMPLEMENTED. AS A RESULT, EVENT REPORTING TO NRC WAS CONFUSED.

  - MISCOMMUNICATION BETWEEN SHIFT AND SUPPLEMENTAL PERSONNEL CONCERNING REPORTING OF EVENT RESULTED IN INCORRECT INFORMATION BEING REPORTED.

4. DOCUMENT CONTROL

- LICENSEE MODIFIED DRAIN VALVES UPSTREAM OF MSIVs TO FAIL CLOSED ON LOSS OF POWER DUE TO CONTAINMENT ISOLATION FUNCTION.

- LICENSEE'S PROGRAM REQUIRES MODIFICATIONS TO BE REFLECTED IN DRAWINGS.

  - DRAWINGS ARE EVENTUALLY PERMANENTLY UPDATED TO REFLECT MODIFICATIONS

    DRAWING FOR THESE VALVES WAS NOT UPDATED IN A TIMELY MANNER (MODIFICATION COMPLETED IN AUGUST, 1993).

DOCUMENT CONTROL (CONTINUED)

- IN INTERIM, PROGRAM DICTATES THAT SIGNIFICANT CHANGES SHOULD BE RED-MARKED ON DRAWINGS.

  ALL CHANGES ARE NOT CLEARLY IDENTIFIED. FOR VALVE MODIFICATION, DRAWINGS INDICATED VALVES WERE STILL FAIL-OPEN, BUT REFERRED TO FOUR SEPARATE MODIFICATION PACKAGES.

  MODIFICATION PACKAGES LOCATED IN A FILING CABINET IN BACK OF CONTROL ROOM.

- PROGRAM HAS NO GUIDANCE ON WHAT CONSTITUTES A SIGNIFICANT CHANGE.

- DECISION MADE BY OPERATIONS MODIFICATION COORDINATOR.

5. CORRECTIVE ACTIONS FROM PREVIOUS EVENT

- IN 1991, UNIT 1 EXPERIENCED A SIMILAR EVENT INVOLVING A LOOP AND SI ACTUATION DUE TO VALVE 1SM-15 PROVIDING AN UNISOLATED STEAM PATH FROM THE SECONDARY.

- CONTRIBUTORS TO COOLDOWN FOR DECEMBER 27, 1993 EVENT:

  - POST-TRIP STEAM LOADS:

    14" VALVE 2SM-15, STEAM SUPPLY TO MOISTURE SEPARATOR REHEATERS, REMAINED OPEN.

    SEVERAL DRAIN LINES FAILED OPEN.

  - AFW FLOW NOT THROTTLED.

- LICENSEE IMPLEMENTED STEP TO CLOSE MSIVs ON RAPID DEPRESSURIZATION.

  - LICENSEE CLAIMED STEP COULD BE REACHED TWO MINUTES FROM INITIATION OF EVENT. STEP WAS NOT REACHED PRIOR TO SI FOR THIS EVENT (7 MINUTES INTO EVENT).

CORRECTIVE ACTIONS FROM PREVIOUS EVENT (CONTINUED)

- WITHOUT FURTHER ACTIONS TO ADDRESS CONTRIBUTORS, AN SI CAN BE EXPECTED FOLLOWING A LOOP.
  - THE RELATIVE CONTRIBUTIONS OF THE COOLDOWN FROM STEAM LOADS AND AUXILIARY FEEDWATER FLOW ARE BEING DETERMINED BY THE LICENSEE AT THIS DATE.
- ACTUAL DESIGN OF THE PLANT IS SUCH THAT A LOOP WILL RESULT IN AN RCS COOLDOWN AND RESULTANT DEPRESSURIZATION.
  - SI FOLLOWING LOOP WAS NOT INCLUDED IN LICENSEE'S FINAL SAFETY ANALYSIS REPORT (FSAR) ANALYSIS.
  - LICENSEE'S FSAR AND INDIVIDUAL PLANT EXAMINATION (IPE) INDICATE THAT A LOOP WILL RESULT IN RCS HEATUP AND RESULTANT PRESSURIZATION.

6. PROBABILISTIC RISK ASSESSMENT INSIGHTS

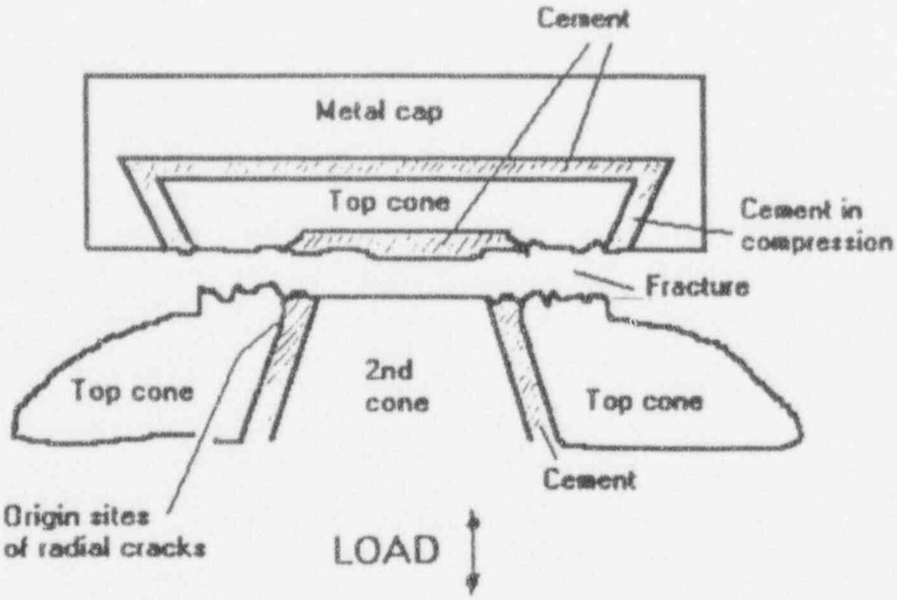
- PRELIMINARY STAFF ANALYSIS OF EVENT ESTIMATES A CONDITIONAL CORE DAMAGE PROBABILITY (CCDP) OF 2×10^{-4}.
  - LOOP SEQUENCES ACCOUNT FOR 1.1×10^{-4} OF TOTAL CCDP.
  - TRANSIENT INDUCED SG TUBE RUPTURE (SGTR) SEQUENCES ACCOUNT FOR 8.3×10^{-5} OF TOTAL CCDP.

    ANALYSIS CONSIDERED PROBABILITY OF EVENT INDUCED SGTR DUE TO DIFFERENTIAL PRESSURE ACROSS SG "B" TUBES OF 1981 PSID.

  - ANALYSIS ACCOUNTED FOR THE MCGUIRE STANDBY SHUTDOWN FACILITY (SSF).

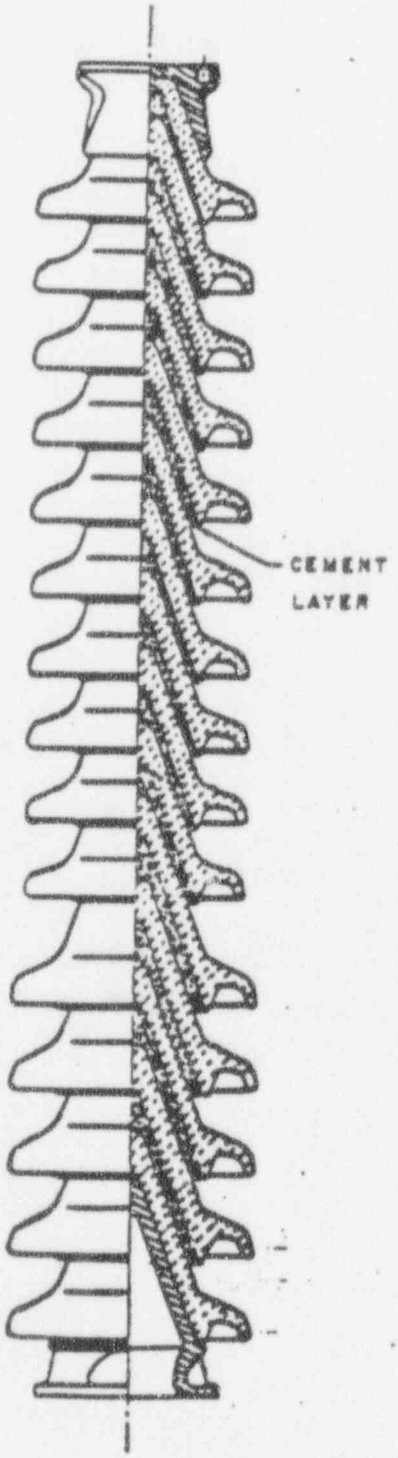
NRC ACTIONS

- AN AUGMENTED INSPECTION TEAM WAS SENT TO SITE TO EVALUATE EVENT.
- AN INFORMATION NOTICE IS BEING DRAFTED TO INFORM LICENSEES OF MSIV BINDING ISSUES.
- ENFORCEMENT ACTION IS BEING CONSIDERED FOR SEVERAL ISSUES.
- AN ANALYSIS OF RELATIVE CONTRIBUTIONS OF STEAM LOADS AND AFW FLOW TO RCS COOLDOWN AND DEPRESSURIZATION, AND A PLAN OF CORRECTIVE ACTIONS HAS BEEN REQUESTED.

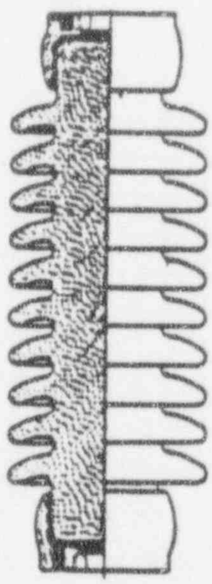


Schematic showing construction of top of insulator. Fracture occurred flush with the top of the second cone.

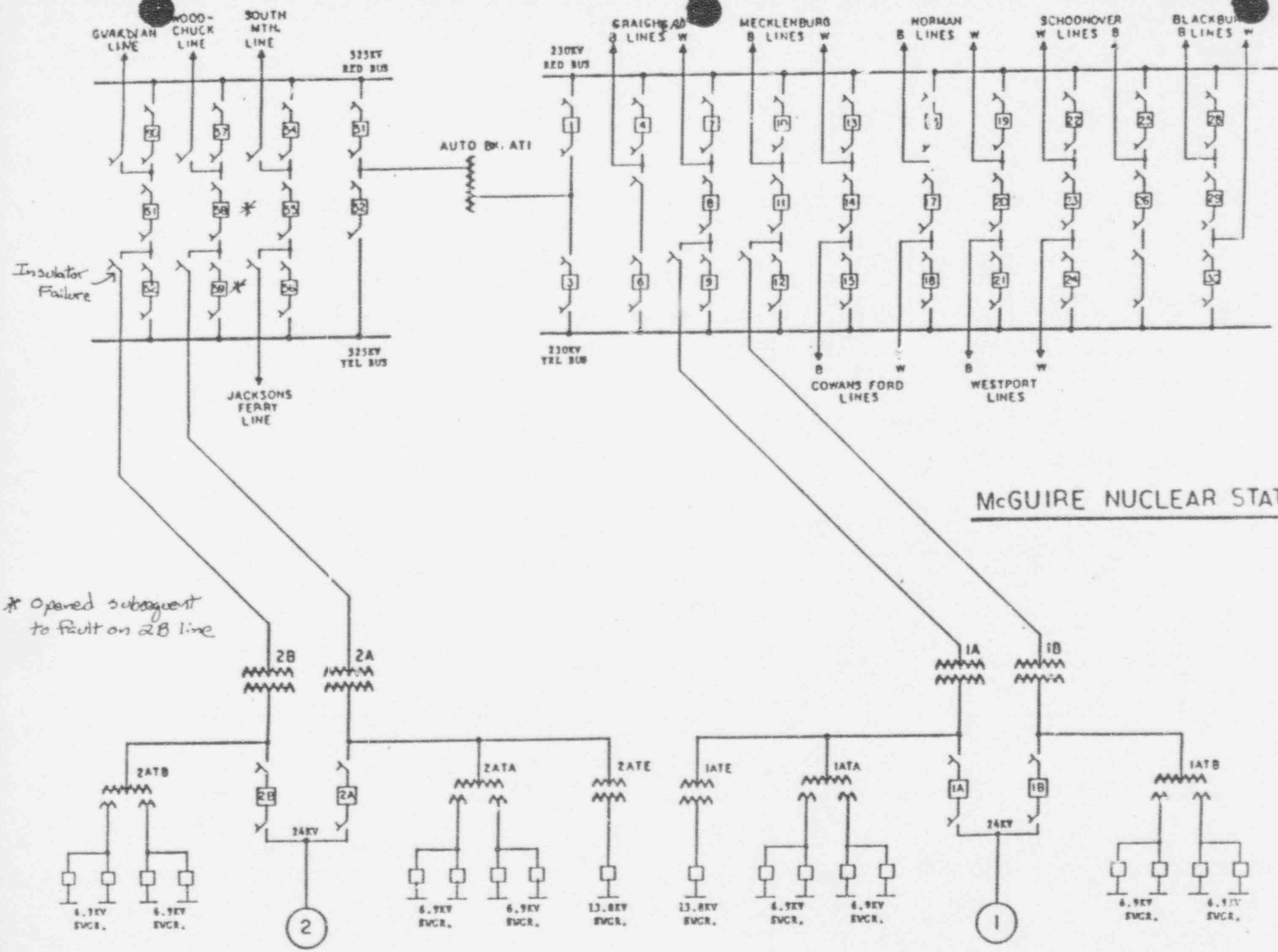
MULTICONE AND SOLID CORE TYPE INSULATOR



MULTICONE TYPE INSULATOR



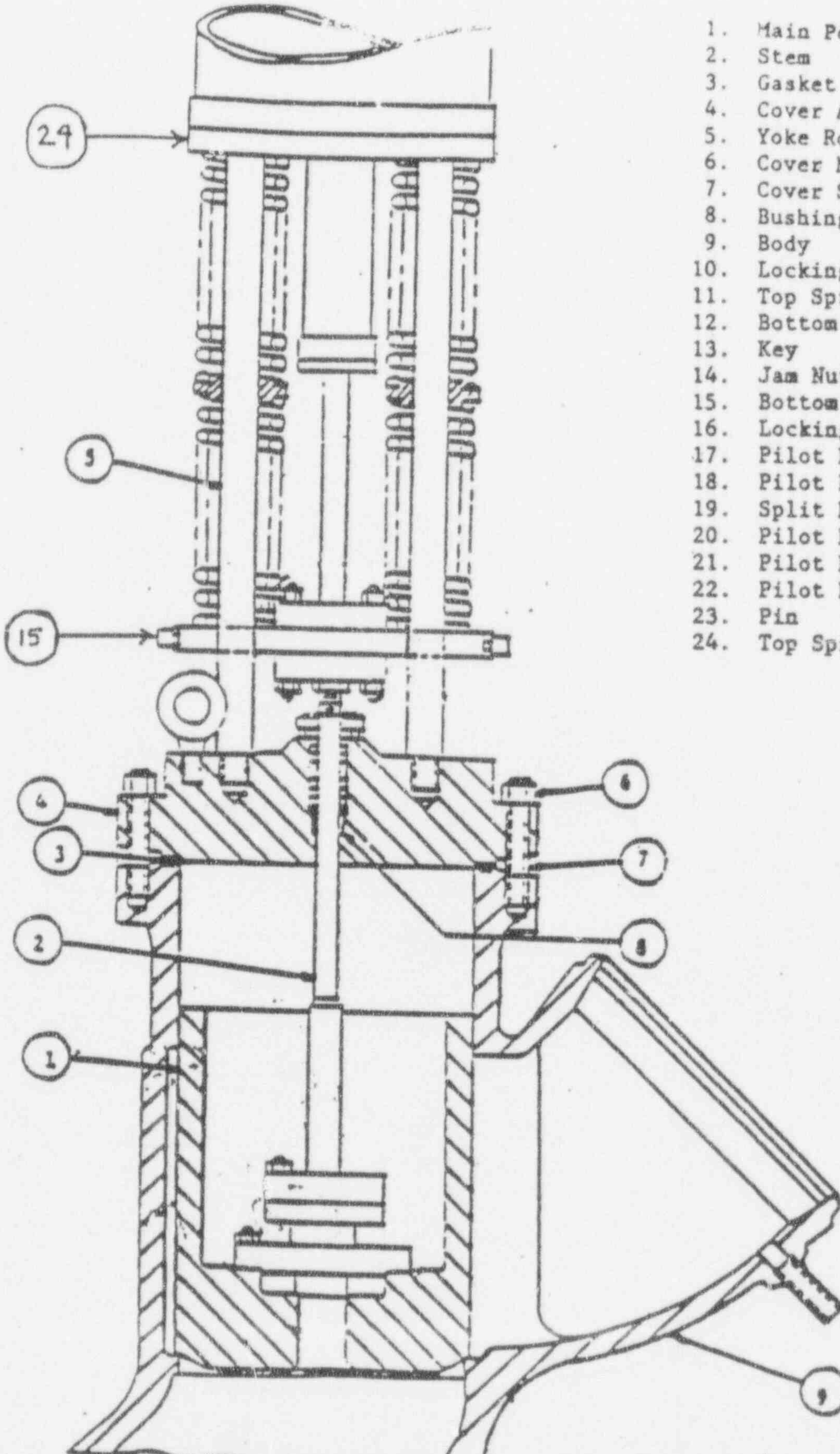
SOLID CORE TYPE INSULATOR



McGUIRE NUCLEAR STATION

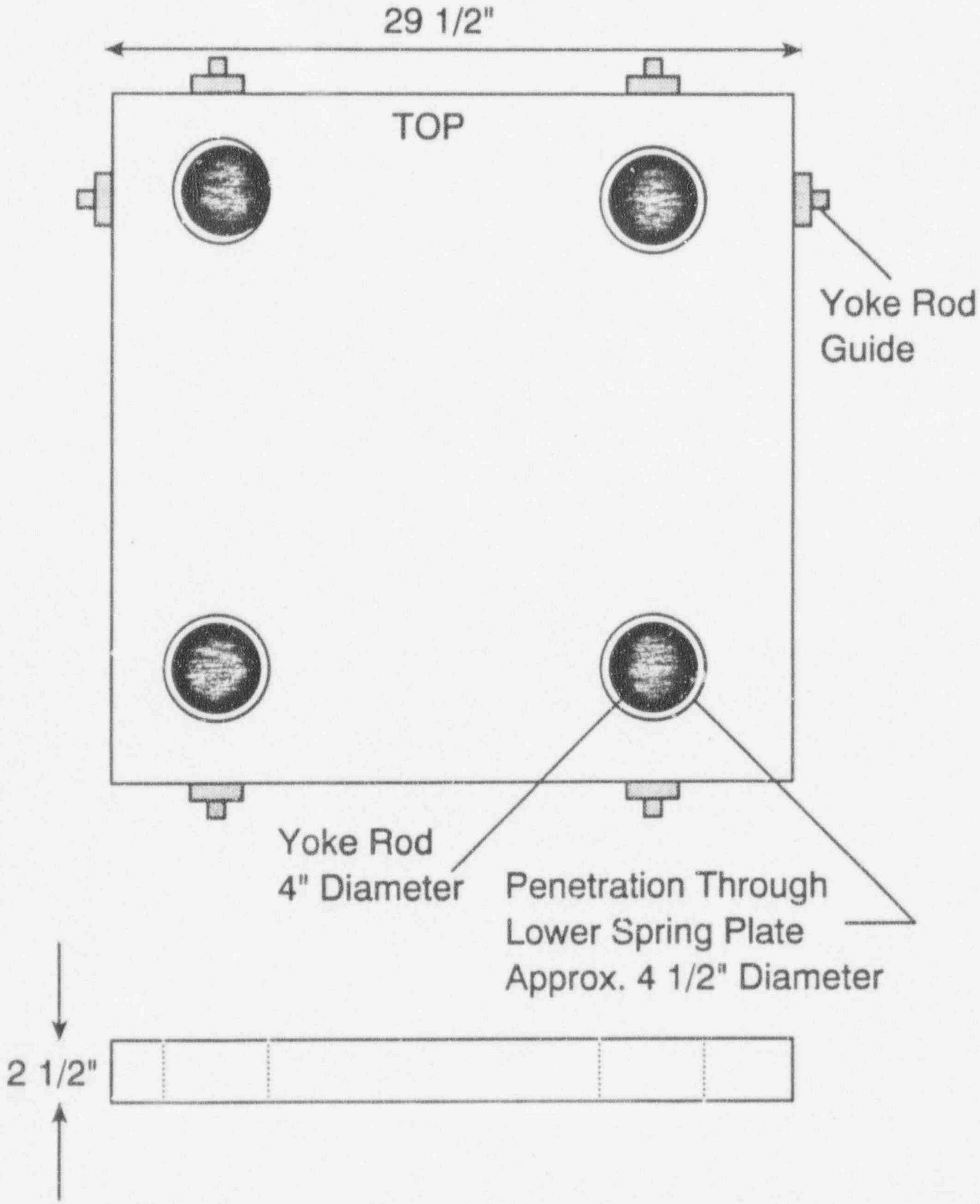
* Opened subsequent to fault on 2B line

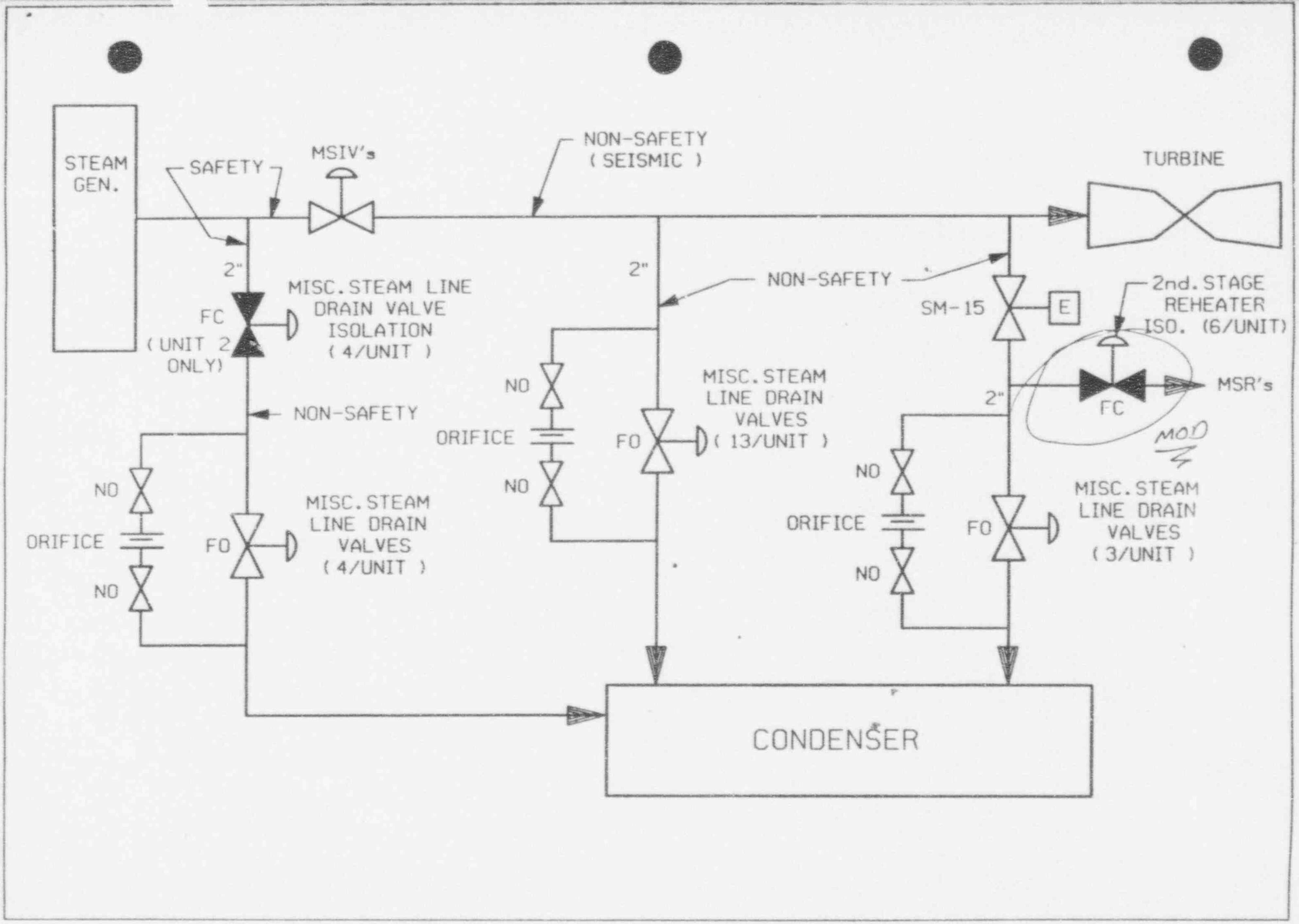
Atwood and Morrill
34 Inch "Wye" Type
Main Steam Isolation Valve
(Valve Body)



1. Main Poppet
2. Stem
3. Gasket
4. Cover Assembly
5. Yoke Rod
6. Cover Nuts
7. Cover Stud
8. Bushing
9. Body
10. Locking Plate
11. Top Spring Seat Cap
12. Bottom Spring Seat Cap
13. Key
14. Jam Nut
15. Bottom Spring Seat
16. Locking Plate
17. Pilot Poppet Cap
18. Pilot Poppet Guide
19. Split Ring
20. Pilot Poppet
21. Pilot Poppet Spring
22. Pilot Poppet Nut
23. Pin
24. Top Spring Seat

Atwood and Morrill
34 Inch "Wye" Type
Main Steam Isolation Valve
(Bottom Spring Seat)




STEAM GEN.
SAFETY
MSIV's
NON-SAFETY (SEISMIC)
TURBINE
2"
FC
(UNIT 2 ONLY)
MISC. STEAM LINE DRAIN VALVE ISOLATION (4/UNIT)
NON-SAFETY
NO
ORIFICE
NO
FO
MISC. STEAM LINE DRAIN VALVES (4/UNIT)
2"
NON-SAFETY
NO
ORIFICE
NO
FO
MISC. STEAM LINE DRAIN VALVES (13/UNIT)
SM-15
E
2nd. STAGE REHEATER ISO. (6/UNIT)
MSR's
FC
2"
MOD
NO
ORIFICE
NO
FO
MISC. STEAM LINE DRAIN VALVES (3/UNIT)
CONDENSER

POTENTIAL USES OF NEW LLNL RESULTS

- IPEEE plant binning.
- Back-fit decisions.
- Cost beneficial licensing actions.
- Probabilistic Risk Assessments.
- Safety Evaluation Reports for future sites.

IMPLICATIONS OF REVISED LLNL SEISMIC HAZARD ESTIMATES ON THE INDIVIDUAL PLANT EXAMINATION OF EXTERNAL EVENTS (IPEEE)

by

Dave Modeen, NUMARC
202-872-1280
Tom O'Hara, YAEC
508-779-6711
John Reed, JBA
415-969-8212

to

Advisory Committee on Reactor Safeguards

March 11, 1994

INDUSTRY COMMENTS (1990/1991) ON IPEEE

- Generic letter request only requires a response; flexibility exists in how to respond
- Analytical calculations appeared to have less practical value than those of the internal events IPE
- More confidence in EPRI hazard estimates as compared to LLNL (1989 version)
- Licensees should customize their examination plans to each site
- Walkdown most beneficial aspect of seismic portion of IPEEE

INDUSTRY AND NRC STAFF ACTIVITIES SUBSEQUENT TO 1991

- NRC Regulatory Improvement Program
- Reflect Safety Goal Policy in NRC staff practices
  - Proposed rule on Reactor Siting
  - Revision to Regulatory Analysis Guideline
- NRC Regulatory Review Group Report
  - Cost beneficial licensing actions (CBLAs)
  - Make more use of risk insights
- Experience gained in seismic reviews to date
- Draft NUREG-1488 (revised LLNL seismic hazard estimates)

NUMARC ACTIONS AND RECOMMENDATIONS

- Inform licensees and NRC staff that change in scope of seismic IPEEE may be warranted as a CBLA
- No need for NRC staff to supplement Generic Letter 88-20
- Document rationale in a "white paper" for industry and NRC staff use
- Licensees inform NRC staff of any change in seismic plans

ACRS PRESENTATION

MARCH 11, 1994 -- BETHESDA, MARYLAND

Revised Livermore Seismic Hazard Estimates for 69 Nuclear Power Plant Sites East of the Rocky Mountains NUREG-1488

- Progression of NRC/LLNL seismic analyses
- Lessons learned from margins studies - the value of the plant walkdown
- Conservative bounding method to estimate core damage frequency
- Quantitative acceptance criterion for reduced level of effort for Seismic IPEEE
- Conclusions

Revised Livermore Seismic Hazard Estimates for 69 Nuclear Power Plant Sites East of the Rocky Mountains
NUREG-1488

- Progression of NRC/LLNL probabilistic seismic hazard analyses (PSHA)

  - NUREG/CR-1582 (1981)
  - NUREG/CR-3756 (1984)
  - UCID - 20421 (1985)
  - NUREG/CR-5250 (1989)
  - NUREG-1488 (1993)

Evolution of the perceived LLNL Probability of Exceeding the SSE at an Eastern U.S. Site

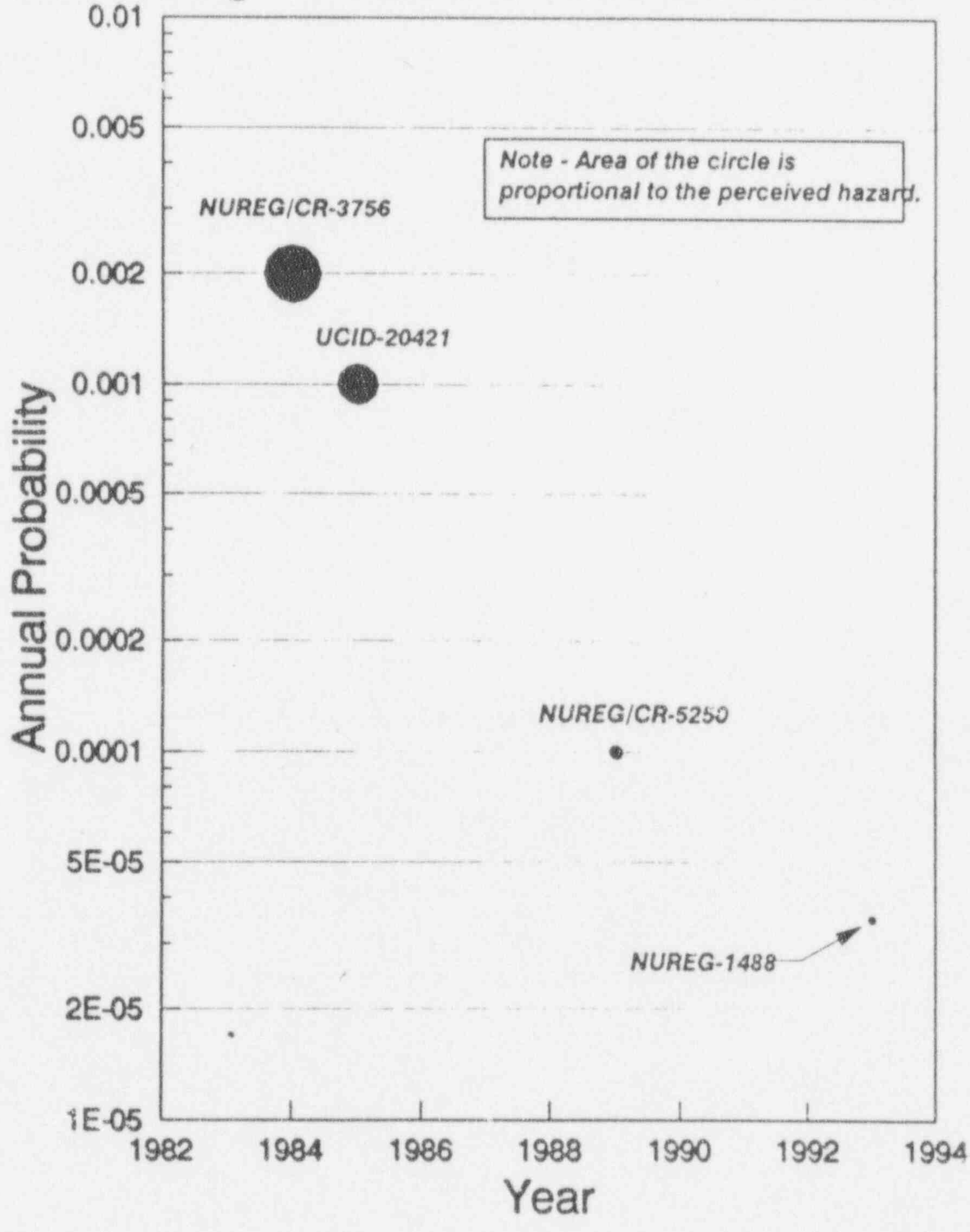


Figure 1

NUREG/CR-1582 (1981) Seismic Hazard Analysis, Application of Methodology, Results, and Sensitivity Studies

- Genesis - Site-Specific Spectrum Program (SSSP), July, 1978
- Program Expanded (December, 1978) to include all SEP sites
- August 1979 - Draft results published for SEP sites
- Letter to SEP plants - August, 1980
- Transition - LLNL takes over, publishes NUREG/CR-1582

Significant By-Products of SEP Probabilistic Analyses

- "These return periods (of the SEP spectra) will still be able to be described as 'of the order of 1,000 or 10,000 years', which is the present description of the spectra and the <u>level implicitly accepted by NRC in recent licensing decisions</u>." NRC Memo, Jackson to Crutchfield (6/23/80)

- Return period <u>perception</u> for the Safe Shutdown Earthquake (SSE) at pre-Appendix A plants was high (100 to 1000 years)

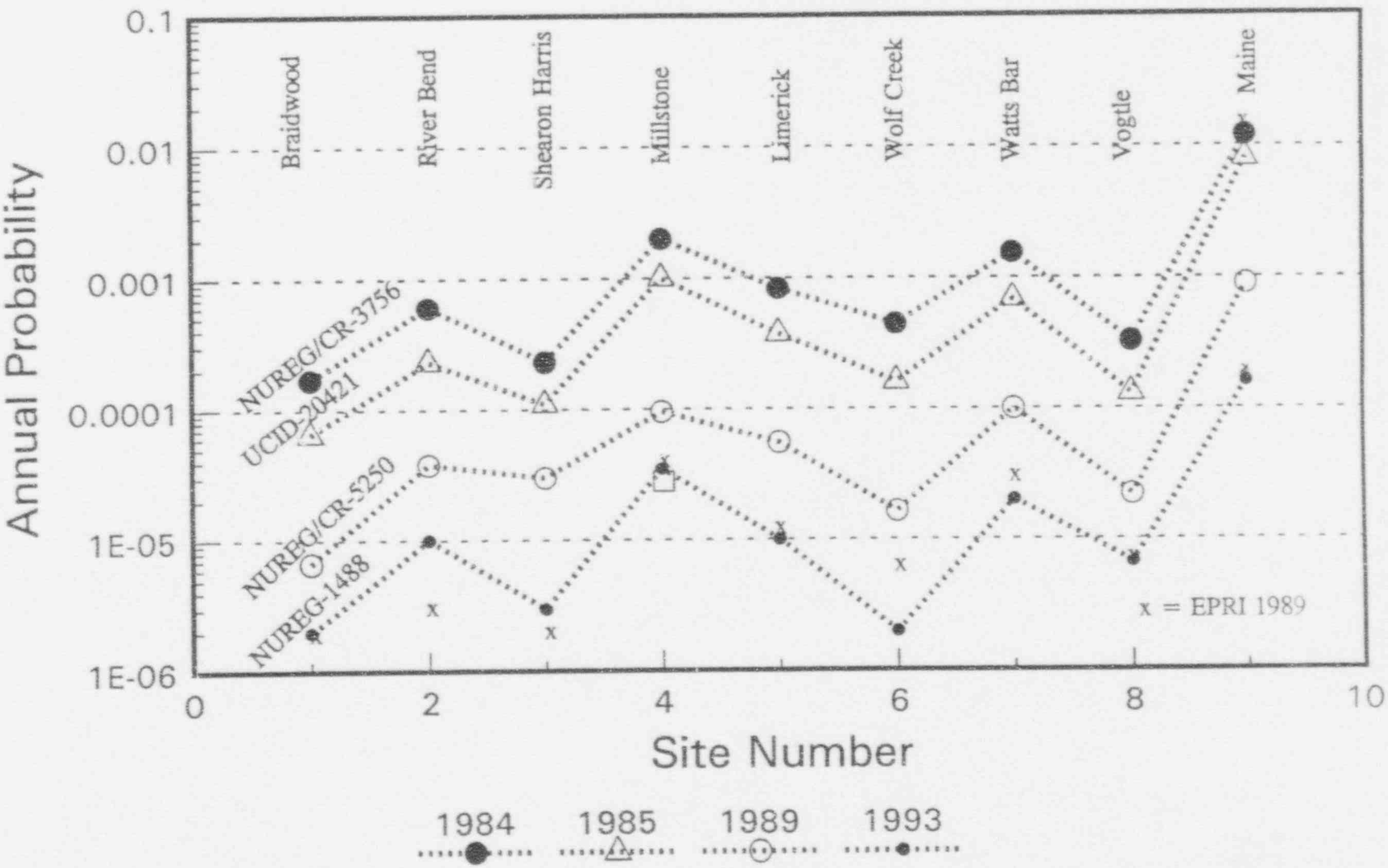
- Post-Appendix A return period <u>perception</u> for SSE about 1,000 to 4,000 years (Seabrook and Wolf Creek)

- Concept of 'relative use of probabilities'

- LLNL results plus 'Charleston Issue' spawned years of heightened NRC sensitivity about seismic issues

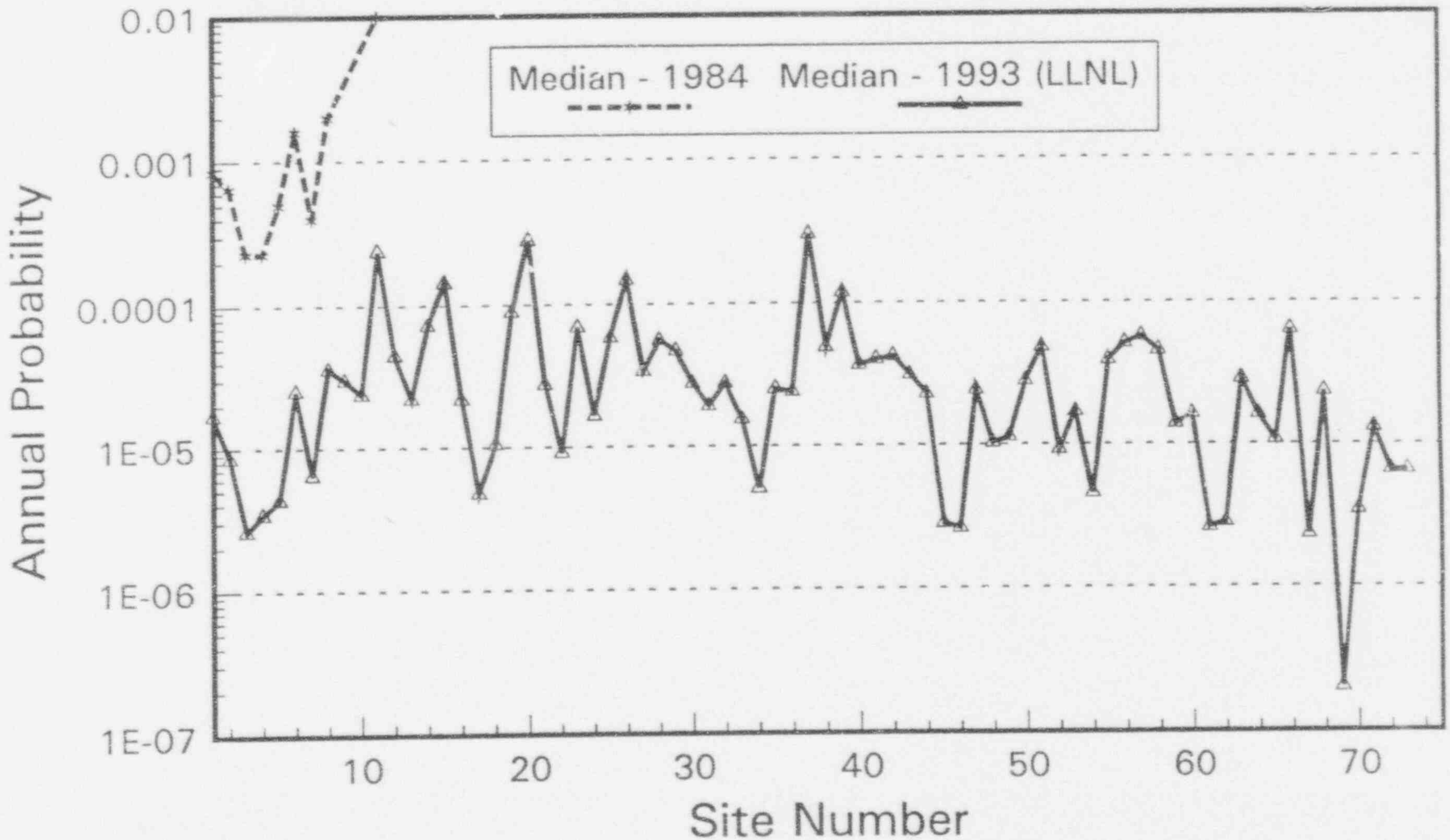
Progression of the LLNL Seismic Hazard Estimates

at 9 Eastern U.S. Sites



Probability of Exceeding the 5 & 10 hz Spectral

Ordinates at EUS NPPs. Comparisons Based on LLNL 1984 & 1993 Results. NUREG-1488 Spectra.



Probability of Exceeding the 5 & 10 hz Spectral

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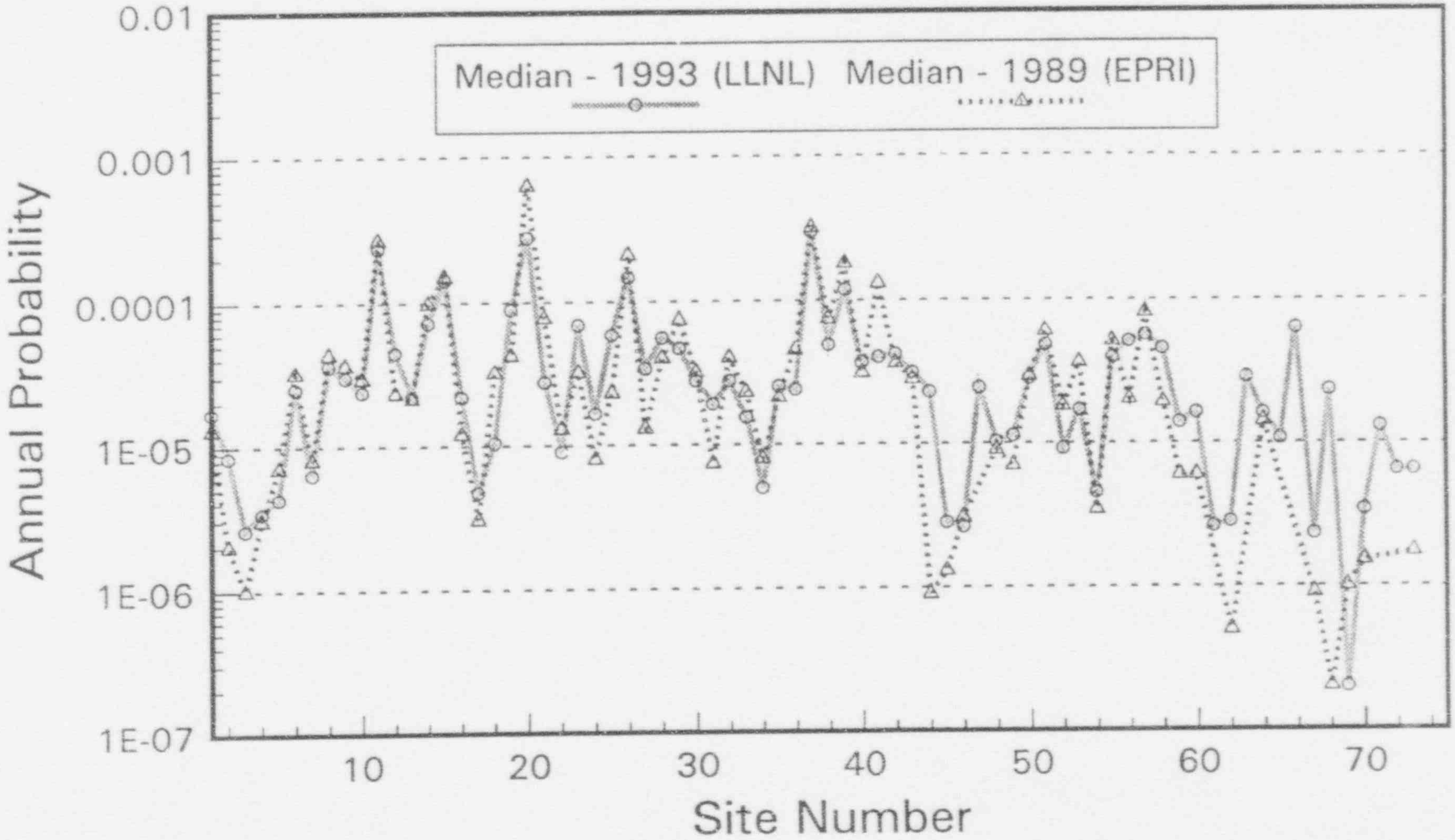

Probability of Exceeding the 5 & 10 hz Spectral

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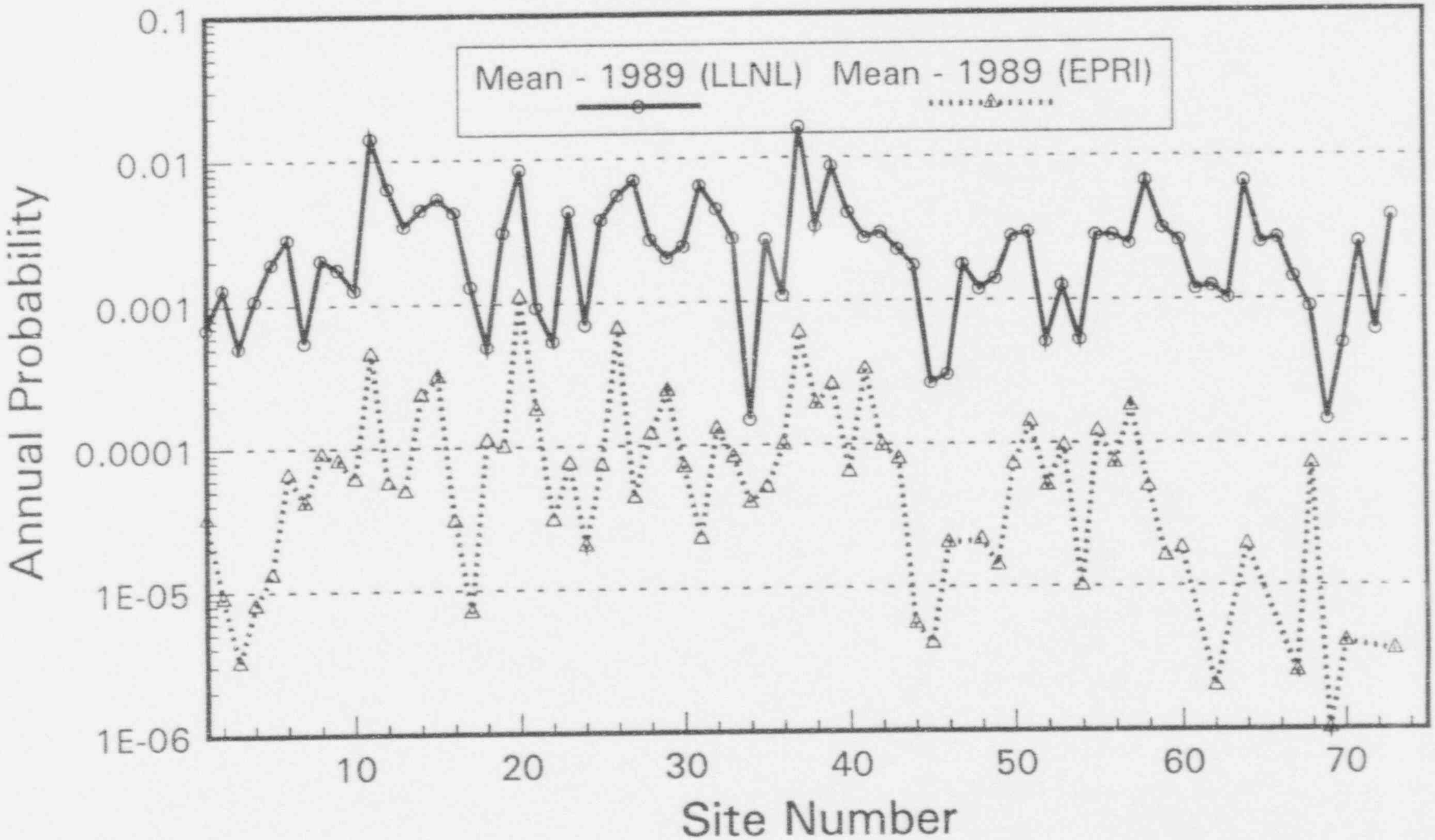
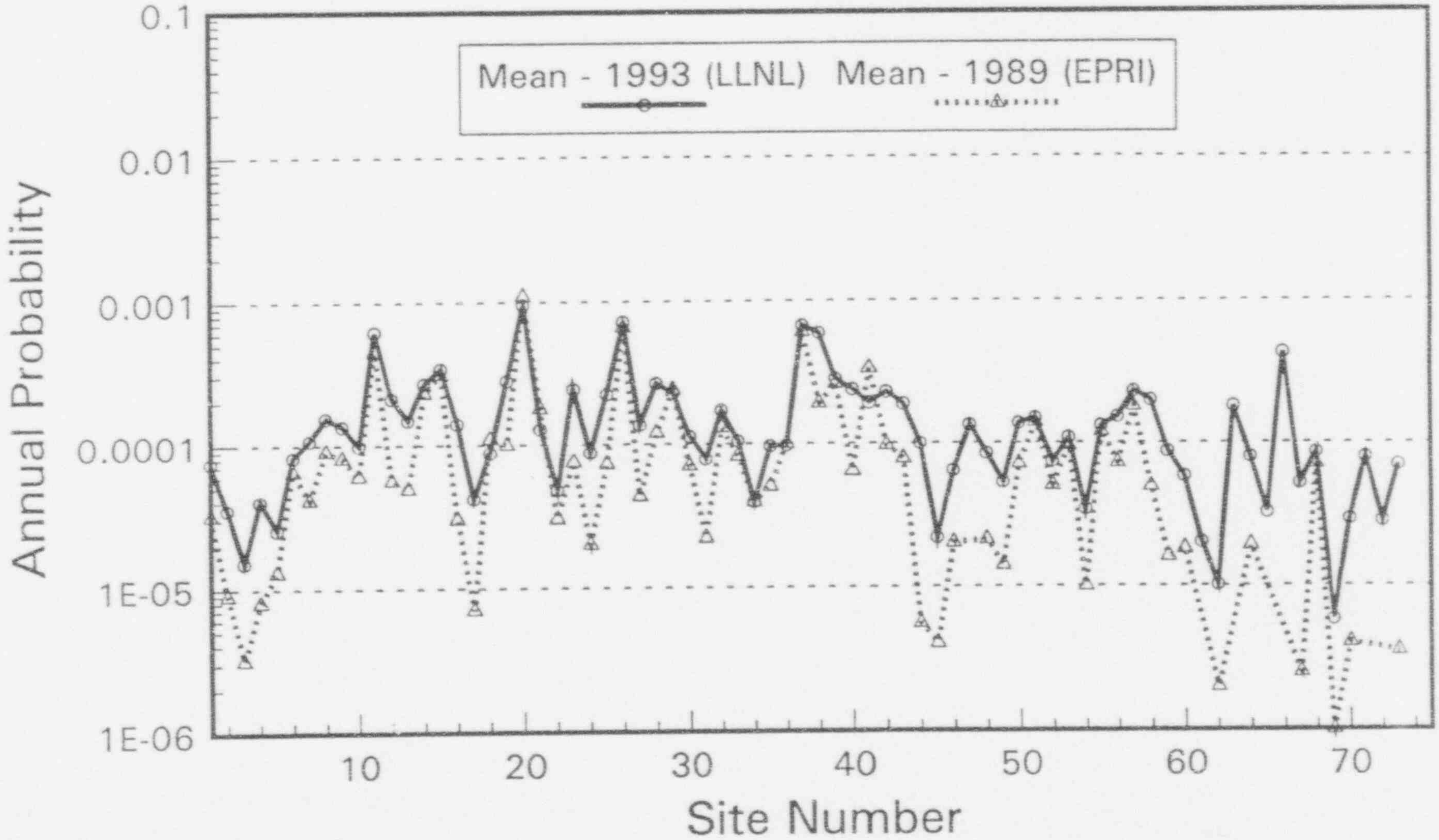


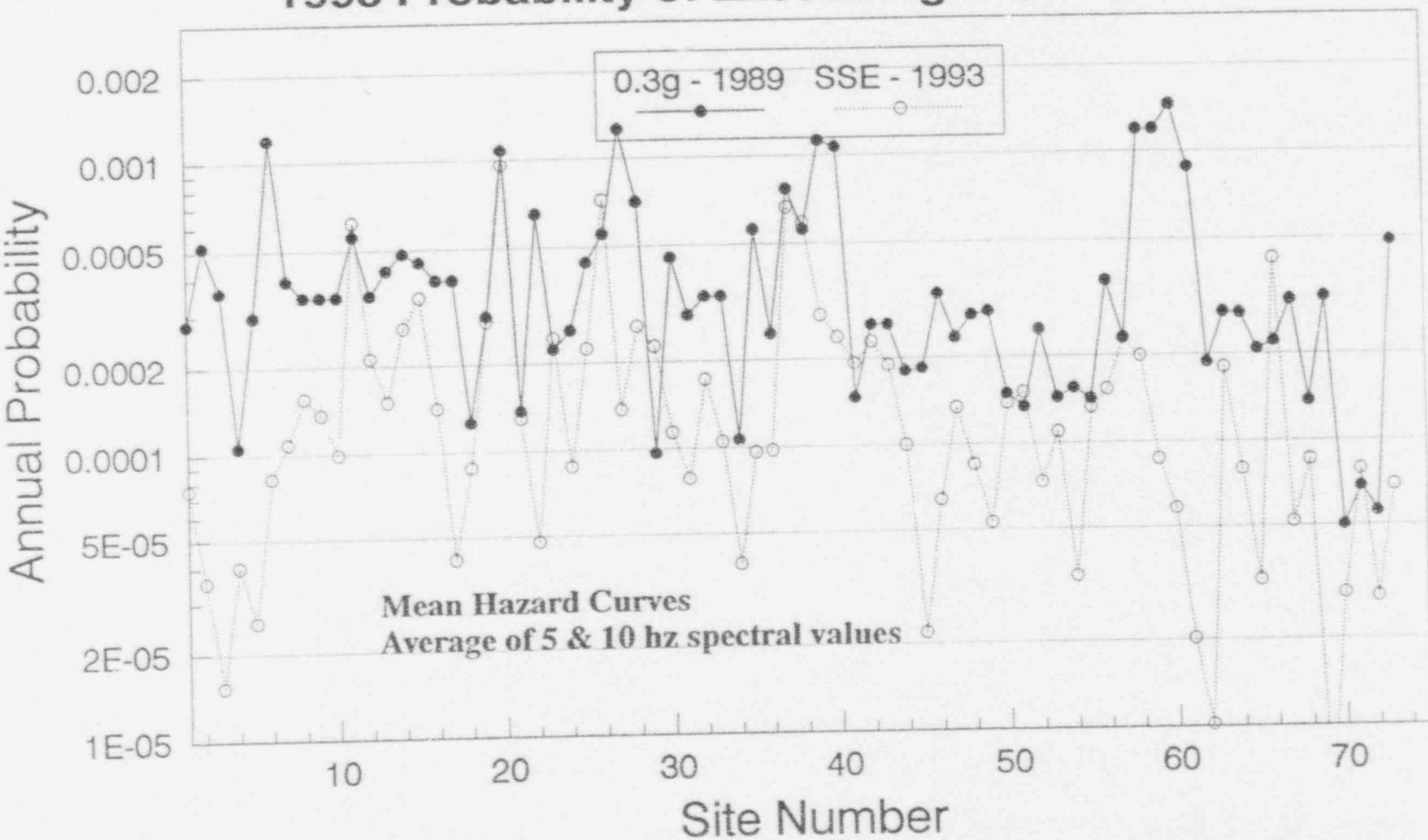
Probability of Exceeding the 5 & 10 hz Spectral

Ordinates at EUS NPPs. Comparisons Based on LLNL and EPRI Results. NUREG-1488 Spectra.



Comparison of LLNL 1989 Probability of

Exceeding a 0.3g NUREG/CR-0098 Spectrum vs the 1993 Probability of Exceeding the SSE



MEAN CORE DAMAGE ESTIMATE

- Detailed walkdown - insures SSE
- Conservative plant fragility parameters based on the SSE
- Mean hazard curves (LLNL & EPRI)
- More refined core damage estimates will be less

REDUCED-SCOPE WALKDOWN

- Plant walkdown is the most important task in a seismic review
- Walkdown process has identified all components that were ultimately modified
- Reduced-scope walkdown requirements are the same as for full or focused-scope reviews

REDUCED-SCOPE WALKDOWN (Cont.)

- Competent review team will identify the same potentially weak elements, independent of the type of seismic review
- Seismic engineers have extensive experience with the limited number of classes of components and issues that are potential weaknesses
- Upon completion of reduced-scope walkdown and modifications, if required, success path components can be assured of achieving SSE

NUCLEAR PLANT SEISMIC MARGIN BEYOND SSE

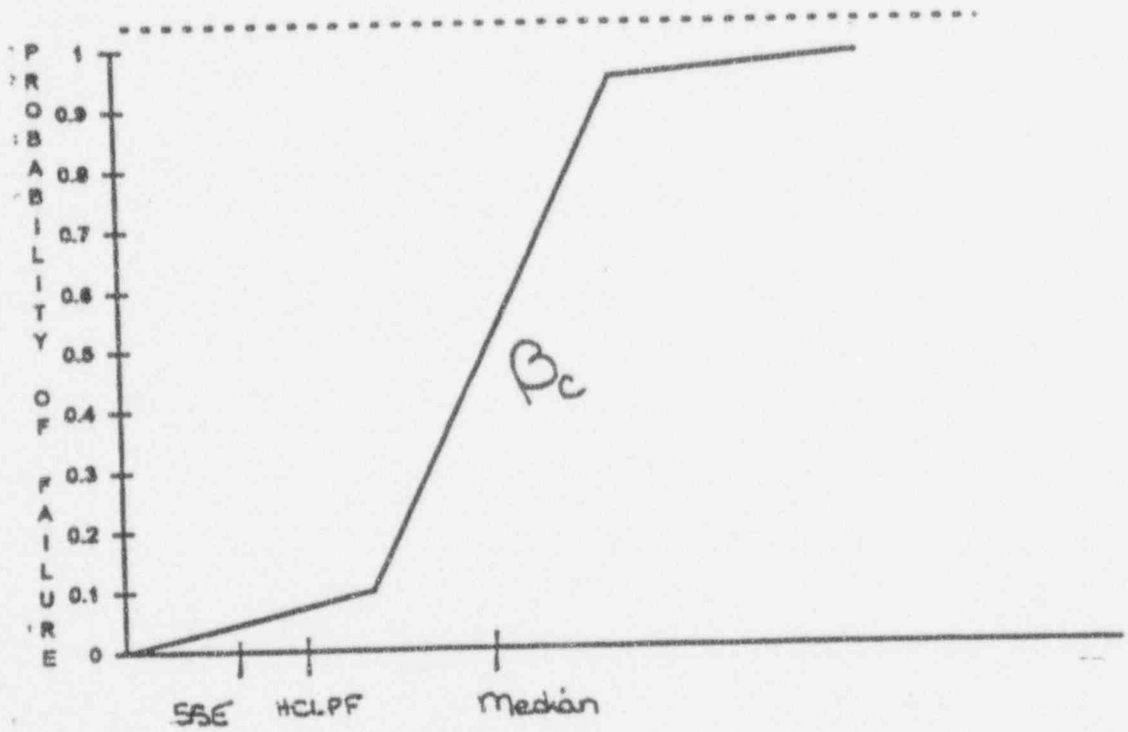
- Past SPRA and SMA studies indicate median factor of safety:

  Structures: 4 to 12 SSE
  Equipment: 3.5 to 20 SSE

- Code requirements lead to <u>minimum</u> seismic capacity of 2.5 to 5 times SSE

- Median capacity for core damage is typically 3 to 6 times SSE

FRAGILITY CURVE



CONSERVATIVE CORE DAMAGE FRAGILITY CURVE

- High Confidence of Low Probability of Failure (HCLPF) capacities typically range from 1.2 to 2.5 SSE

  HCLPF = 1.25 SSE is conservative

- Past mean core damage fragility curves β_c values range from 0.3 to 0.4

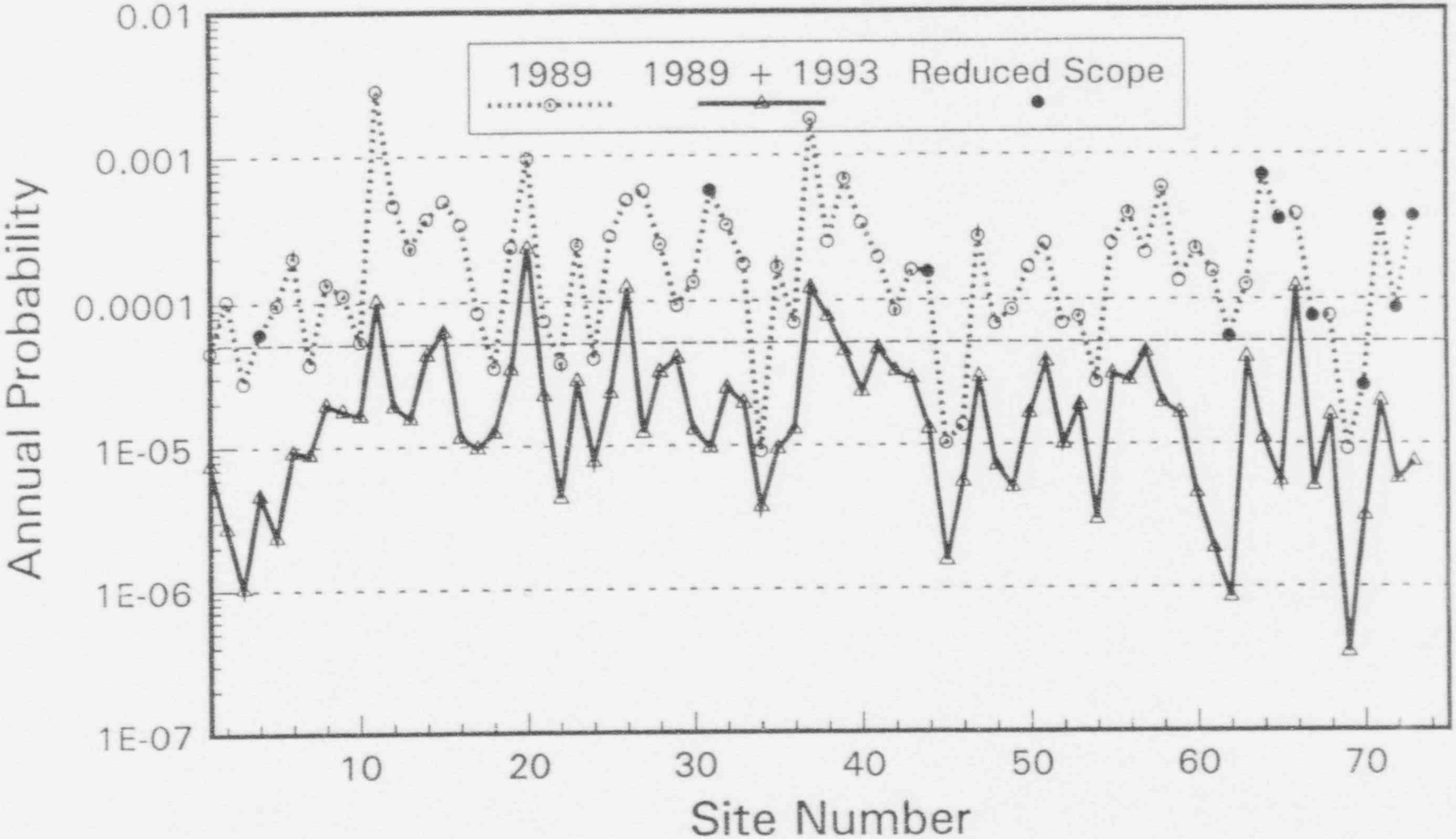
  $\beta_c = 0.33$ is conservative

- Conservative estimate of mean core damage frequency can be made with fragility curve:

  Median = 2.67 SSE
  β_c = 0.33

Comparison of Estimated Mean Core Damage

Frequencies - 1989 LLNL + 1989 EPRI vs. 1993 LLNL + 1989 EPRI



JUSTIFICATION AND CRITERION FOR REDUCTION IN IPEEE PROGRAM

- Significant reduction in seismic hazard
- Walkdown most cost-effective and beneficial aspect of IPEEE seismic program
- Conservative upper bound core damage calculation
  - Conservative input assumptions
  - Mean Hazard curves (LLNL & EPRI)
  - More refined core damage estimates will be lower
- Core damage precedent
  - NUREG-1407 average seismic contribution about 5×10^{-5}
  - NUREG-1150 average seismic contribution about 5×10^{-5}
  - Internal IPE average about 6×10^{-5}
- 5×10^{-5} is lower in probability than all but one of the original reduced scope plants

CONCLUSIONS

- Significant reduction in seismic hazard
- Walkdown most cost-effective and beneficial aspect of IPEEE seismic program
- Conservative upper bound core damage calculation
  - Conservative input assumptions
  - Mean Hazard curves (LLNL & EPRI)
  - More refined core damage estimates will be lower

CONCLUSIONS (Cont'd)

- Core damage precedent - 5×10^{-5}
- Reduced scope for all but a handful of plants
- Cost savings from focused scope to reduced scope - $250,000
- The benefit is not justified for this expenditure
- Reduced scope effort satisfies the Generic Letter 88-20, Supplement 4, "Request for Information"

NRR STAFF PRESENTATION
TO THE ACRS

SUBJECT: LLNL Eastern United States
Seismic Hazard Program

DATE: March 11, 1994

PRESENTER: Phyllis Sobel

TITLE/BRANCH/DIVISION: Project Manager
LLDR/LLWM/NMSS

TELEPHONE NO: 504-2738

BACKGROUND

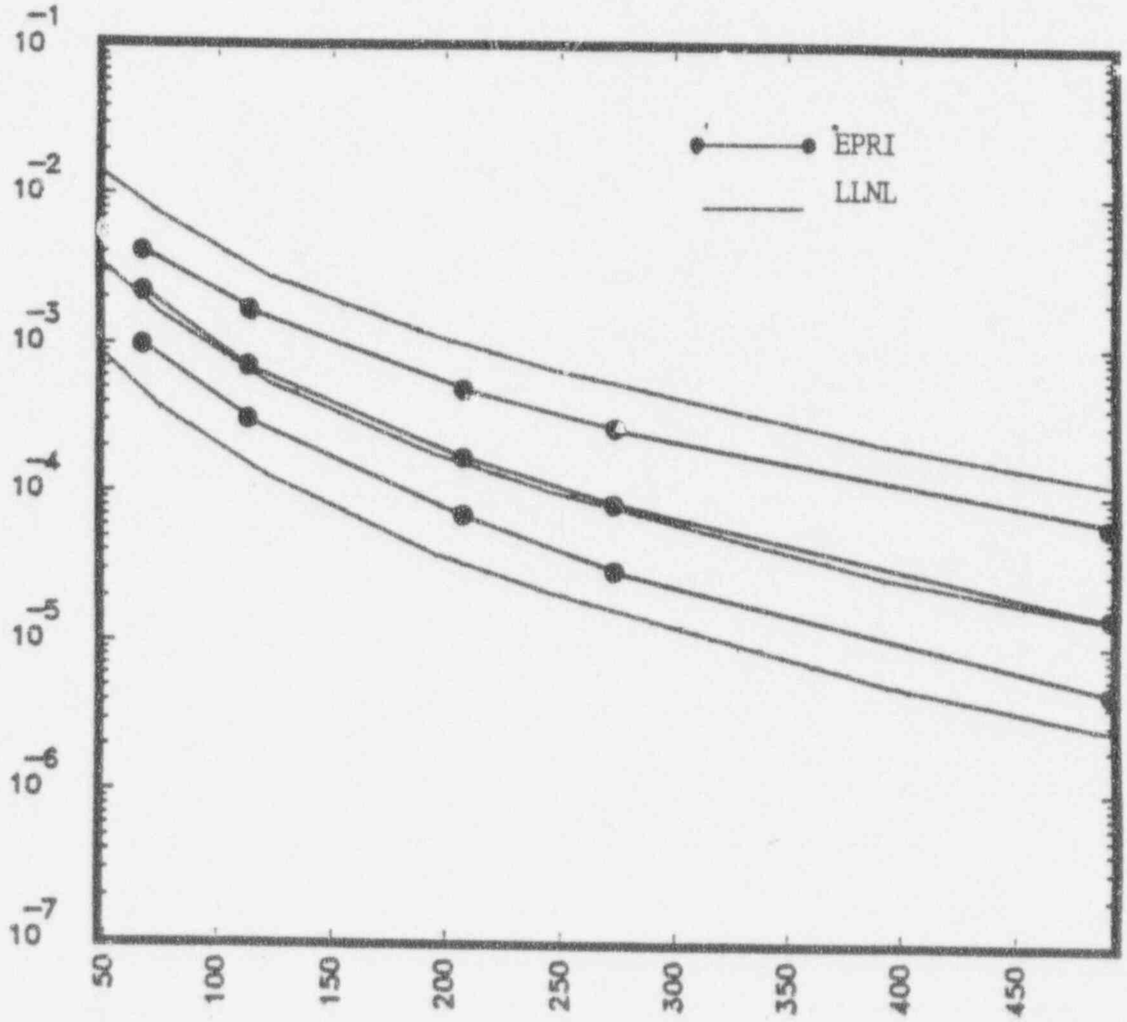
- LLNL developed probabilistic seismic hazard estimates at all operating plant sites east of the Rocky Mountains for the NRC (NUREG/CR-5250).

- EPRI developed seismic hazard estimates at 57 of the Eastern U.S. sites.

- The differences between the LLNL and EPRI seismic hazard estimates were addressed in NUREG/CR-4885.

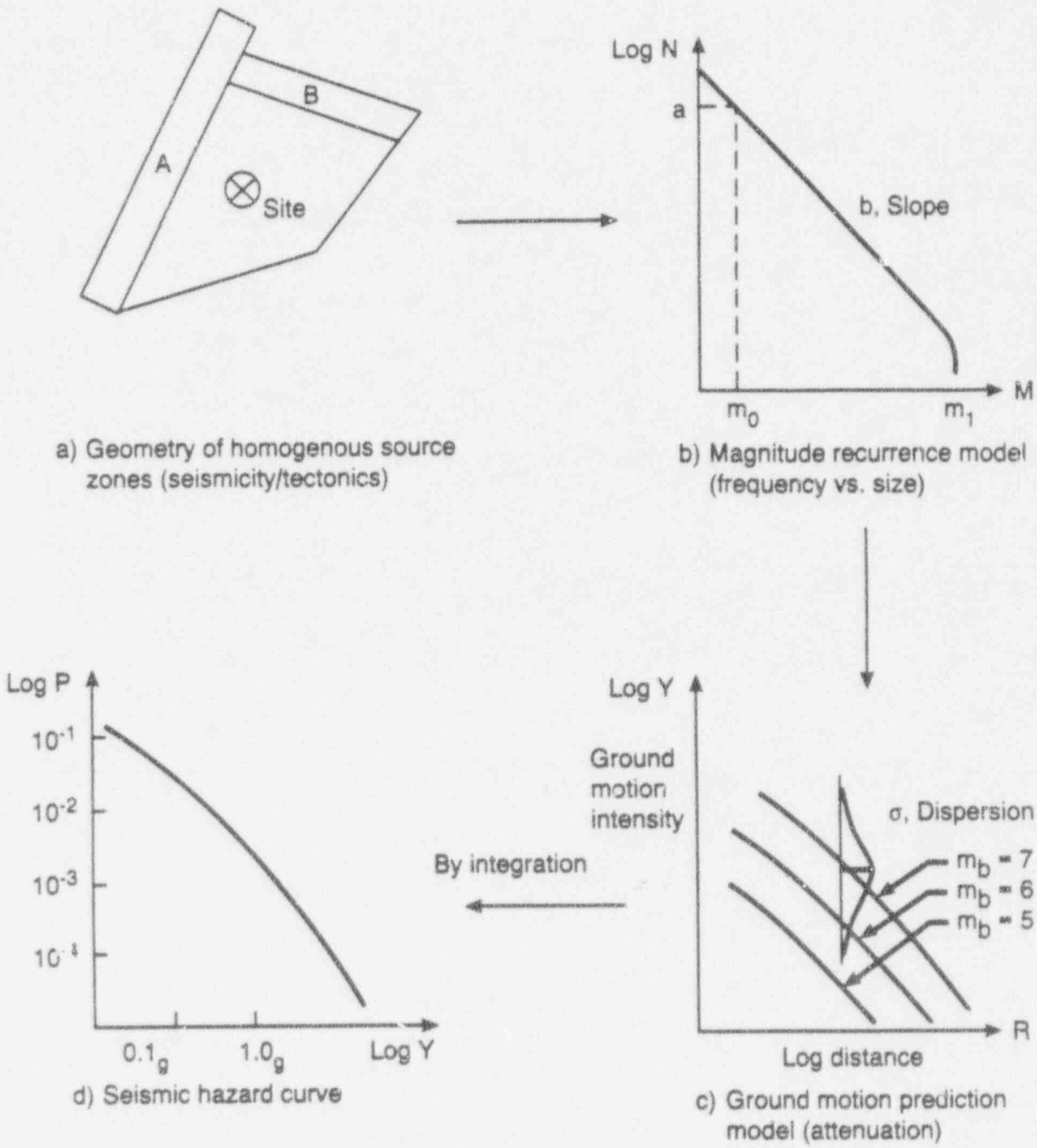
- Based on LLNL work done for DOE in the last few years, NRC sponsored LLNL to conduct a limited reelicitation of the seismicity and ground motion experts to refine estimates of uncertainty.

HAZARD CURVE USING ALL EXPERTS

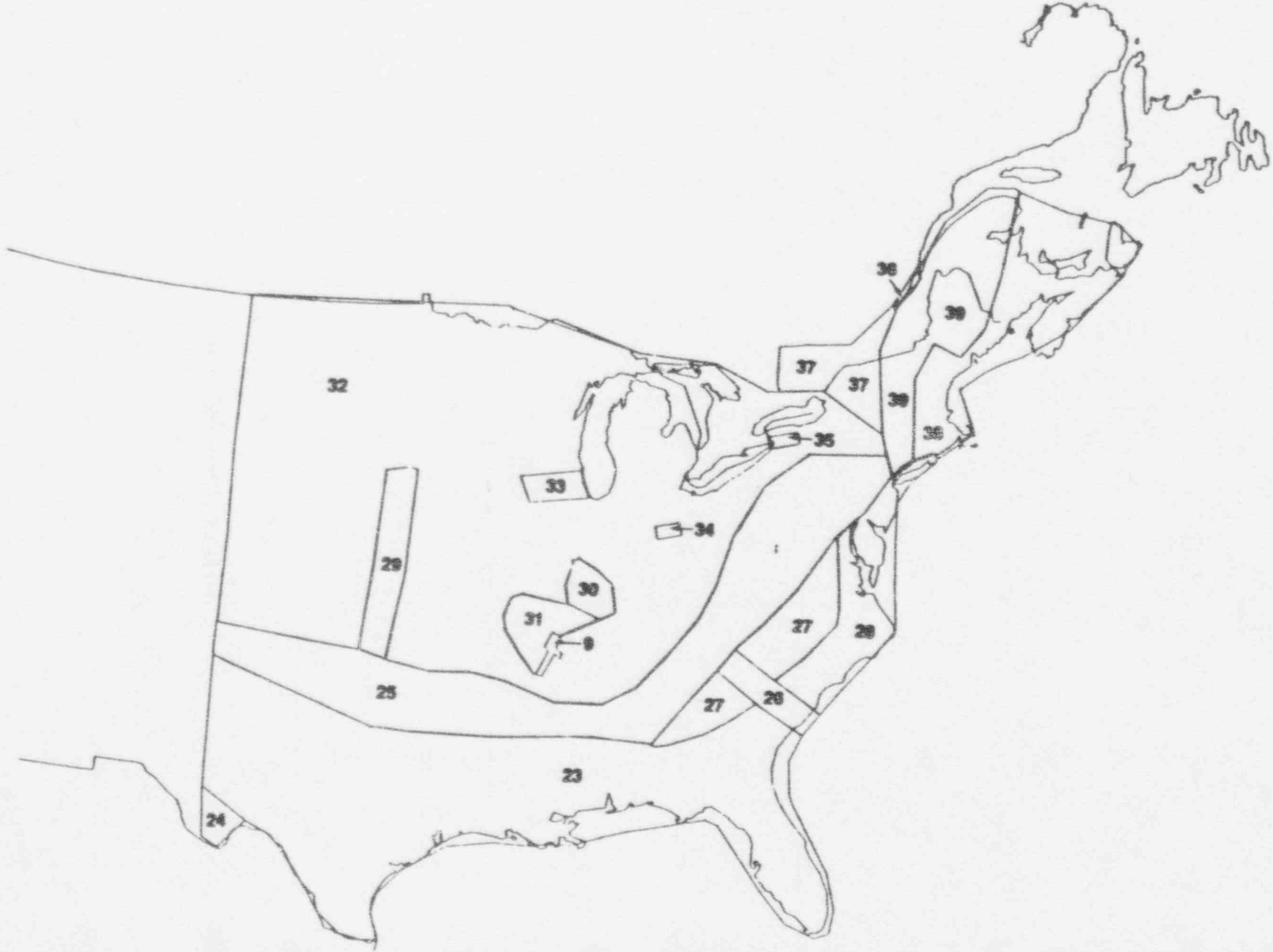


LIMERICK

Median, 15th and 85th hazard curves for the Limerick site using the Nuttli (1984) ground motion model, no site correction and considering only the contribution of earthquakes greater than magnitude 5.



Four steps involved in a probabilistic seismic hazard analysis.



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1992 ELICITATION OF SEISMICITY EXPERTS

- In NUREG/CR-5250, higher uncertainties associated with seismic recurrence rates at larger magnitudes due to 1980's elicitation process (elicitation of a and b values (intercept on the y-axis and slope) and their uncertainties).

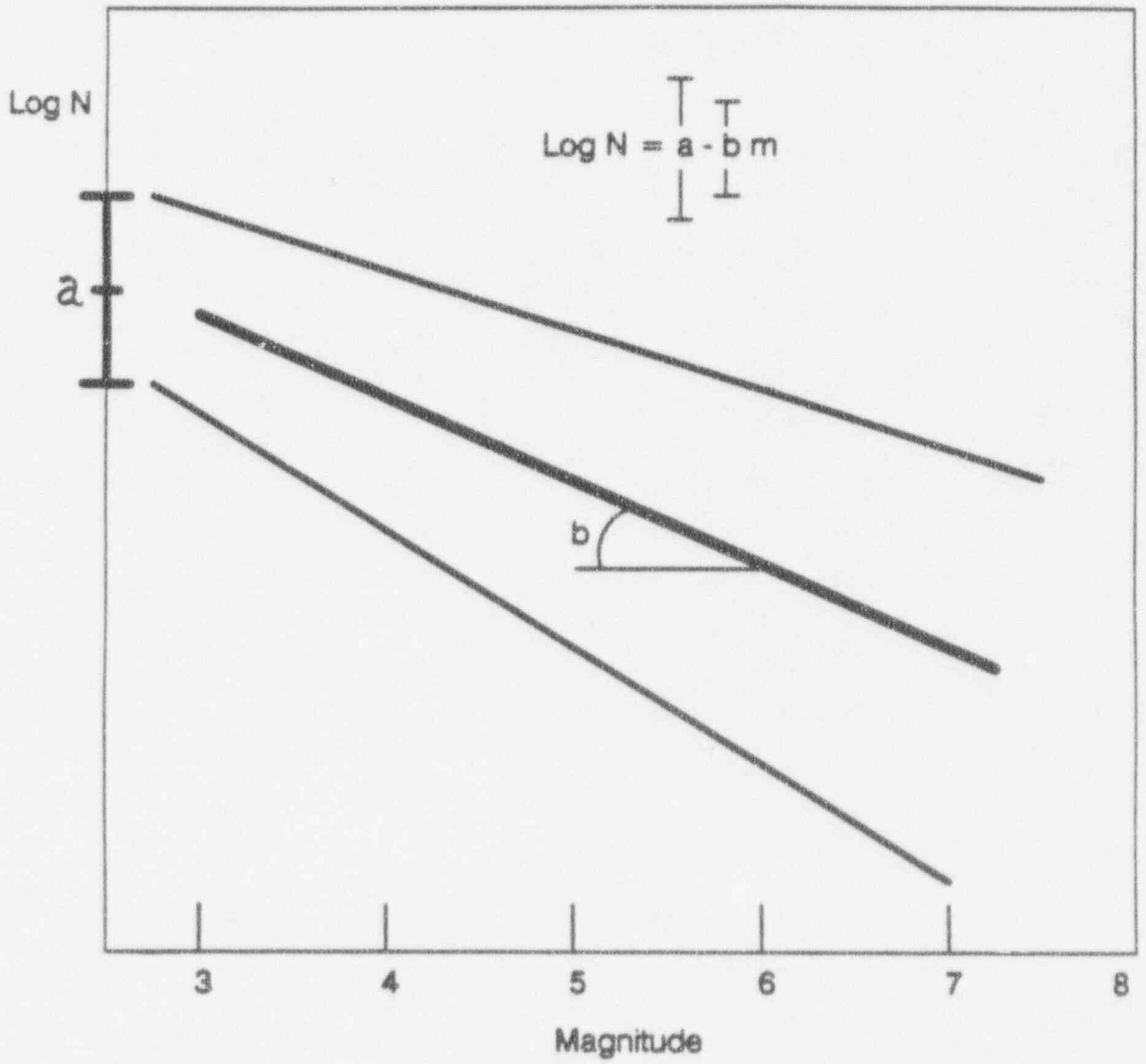
- In 1992, to improve the modeling of uncertainty, seismicity recurrence rates (including uncertainty) were elicited by frequency of occurrence at specific magnitudes.

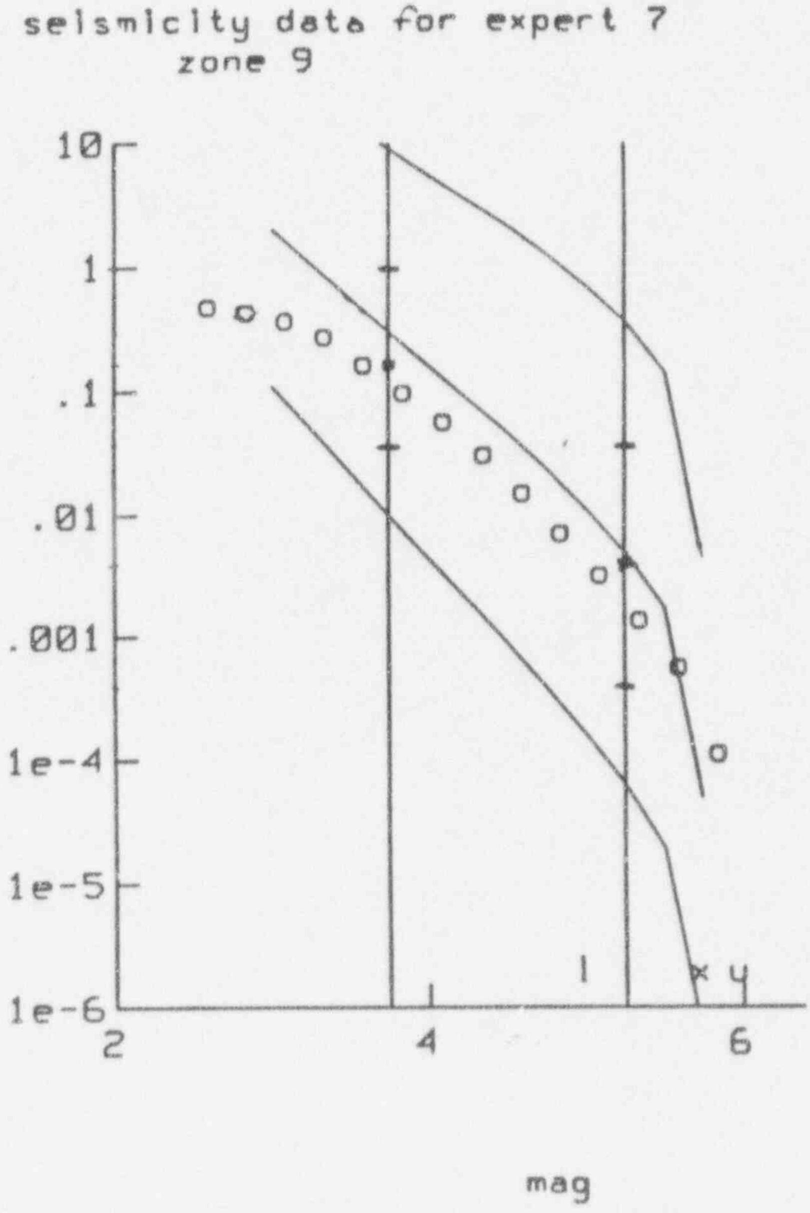
- Seismicity experts were more comfortable with 1992 approach.

- Uncertainty in seismicity recurrence curves reduced.

- Zonation was not re-elicited.

Figure 1 - Earthquake recurrence rates - number of earthquakes versus magnitude. Uncertainties in estimates of a (y-intercept) and b (slope) can lead to unrealistically large estimates of recurrence rates at larger magnitudes.





o - Data from historical and instrumental seismicity catalogs

ELICITATION OF GROUND MOTION EXPERTS

- Workshop with experts on expert elicitation considered type of information to be elicited, the format of the elicitation, and the aggregation of expert opinion. Recommendations used in ground motion elicitation.

- Updated ground motion estimates based on current state of knowledge.

- Peak ground acceleration and spectral acceleration estimates were made for specific magnitudes and distances (i.e. magnitude 6.0 at 25 km).

- Greater emphasis placed on uncertainty.

- LLNL aggregated experts' ground motion inputs into a composite ground motion model.

ELICITATION OF GROUND MOTION EXPERTS

1980's	1992/1993
Five ground motion experts.	Seven ground motion experts.
Questionnaires.	Experts interviewed individually.
Experts provided models that estimated ground motion as a function of earthquake magnitude and distance from the site.	Experts provided estimates of ground motion for selected earthquakes magnitudes and distances from the site.
LLNL combined the inputs from all pairs of seismicity and ground motion experts individually to develop an uncertainty distribution estimate of hazard for each pair of experts.	LLNL aggregated* the ground motion inputs to derive a composite ground motion distribution to be used as input for the hazard calculations.

* The ground motion inputs were combined to form an empirical uncertainty distribution for median estimates of ground motion. Then an empirical conditional uncertainty distribution was developed for the standard deviation of ground motion.

RESULTS

- The 1993 updated LLNL hazard estimates are lower than the 1980's results.

- The differences between the LLNL and EPRI hazard estimates have been reduced.

- The largest differences between the 1993 LLNL and EPRI hazard estimates are at low seismicity and soil sites.

- The differences between the 1993 LLNL and EPRI hazard estimates are greatest for accelerations above the level of the Safe Shutdown Earthquake. Potential for significant influence on PRA results.

- Updating the seismicity inputs reduced the mean hazard estimates by a factor of 5 at 0.2g.

- Updating the ground motion inputs reduced the mean hazard estimates by a factor of 1 to 10 at 0.2g.

- Further sensitivity results are needed.

Figure 2 - Comparison of 1989 LLNL, 1992 LLNL and EPRI estimates of probability of exceeding peak ground acceleration per year versus acceleration - Pilgrim site.

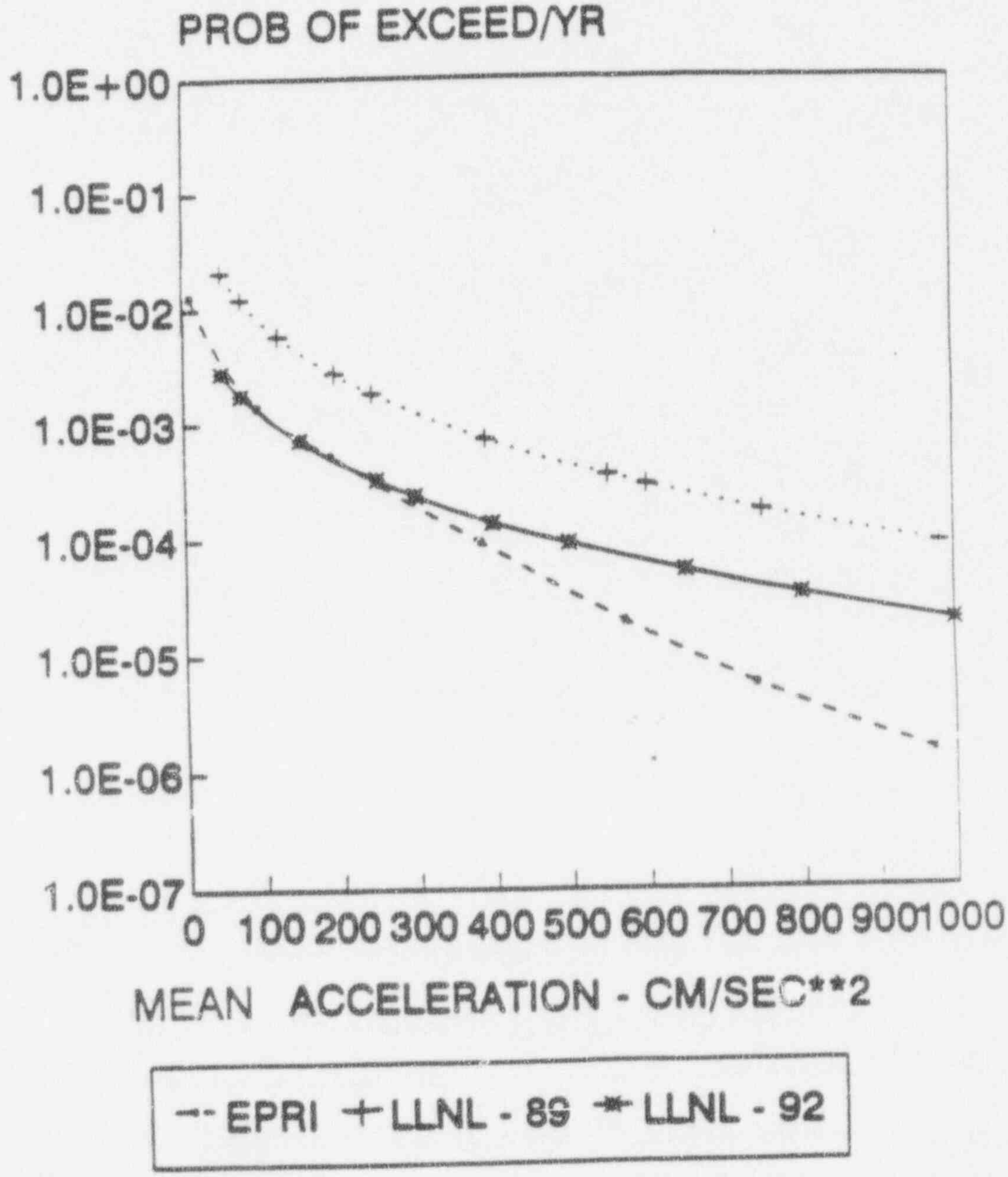


Figure 3 - Comparison of 1989 LLNL, 1992 LLNL and EPRI estimates of probability of exceeding peak ground acceleration per year versus acceleration - Shearon Harris site.

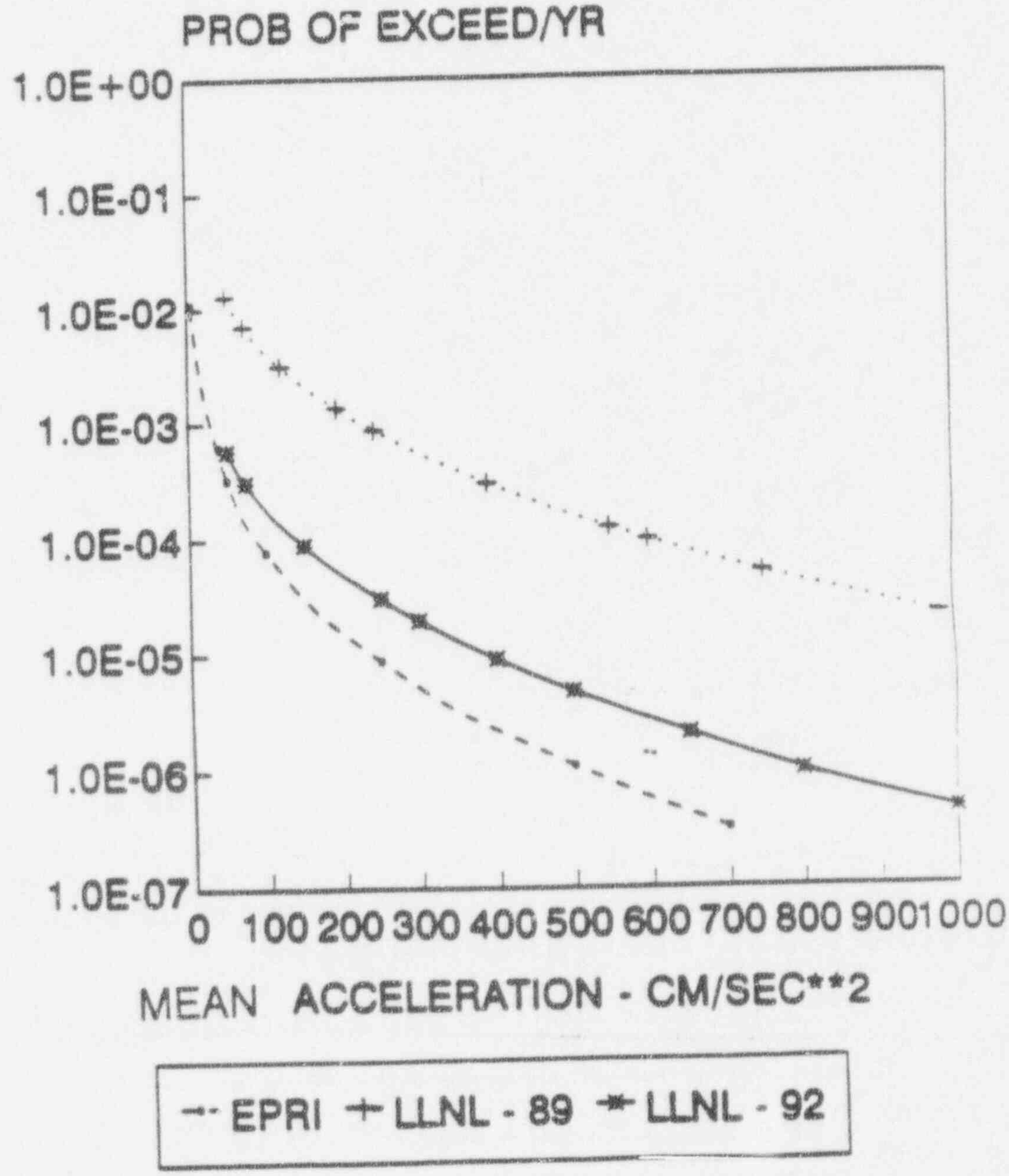
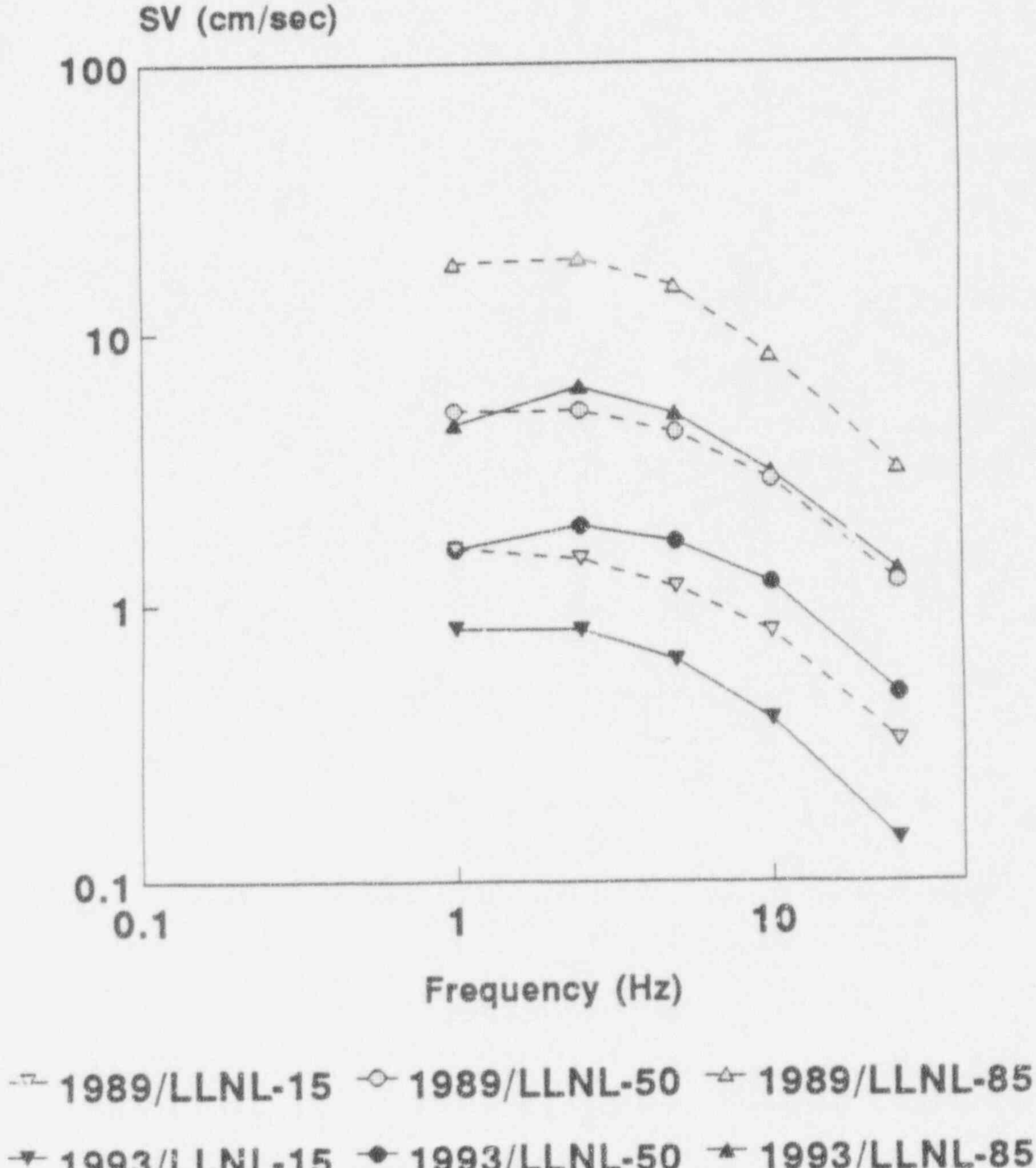


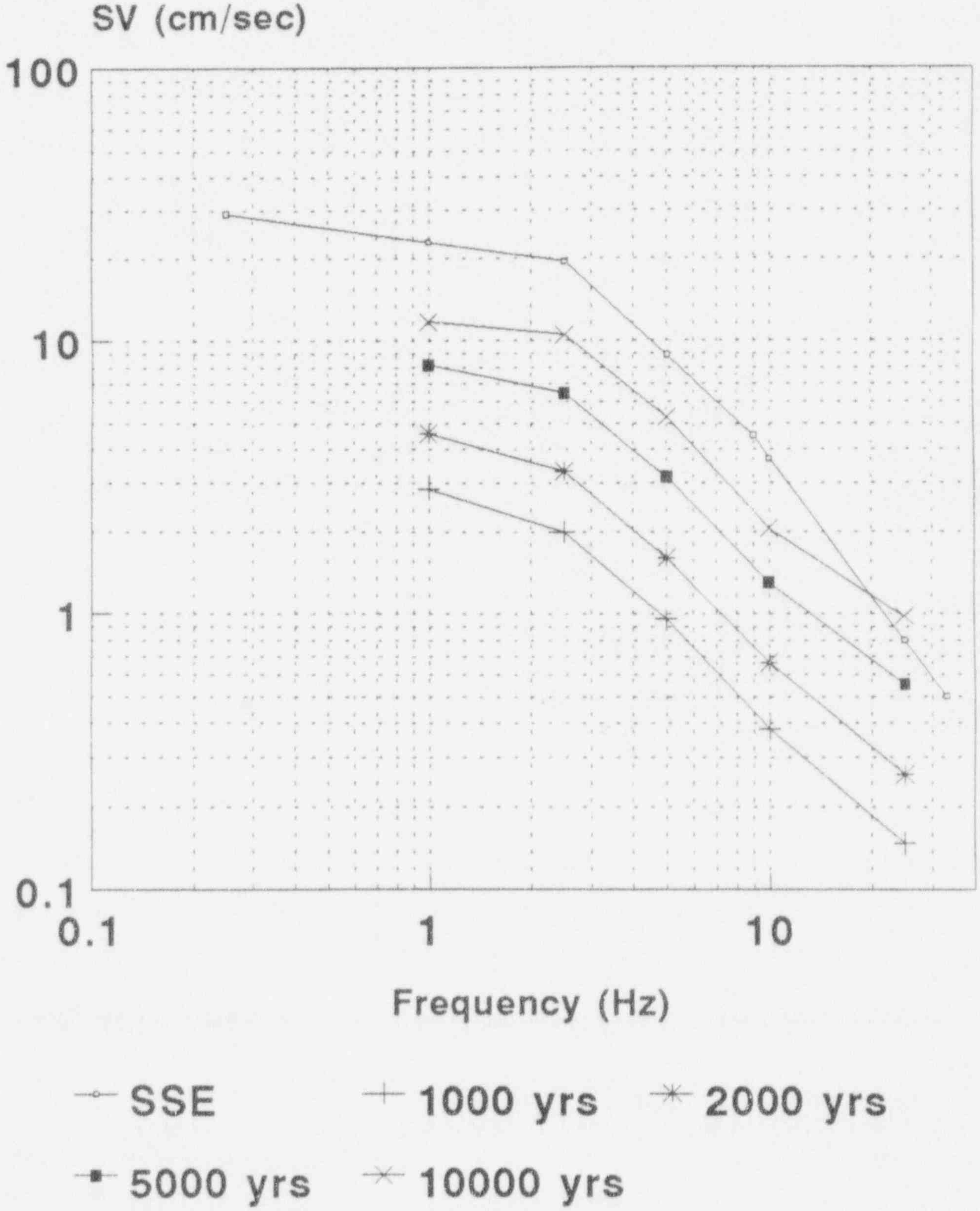
Figure 4 - Seabrook 1,000 Year
Uniform Hazard Response Spectra -
1989 versus 1993 LLNL Hazard Estimates



RIVER BEND

Horizontal Spectra - 5% Damping

SSE (0.10g - RG 1.60) vs 1993 LLNL Mean Estimates

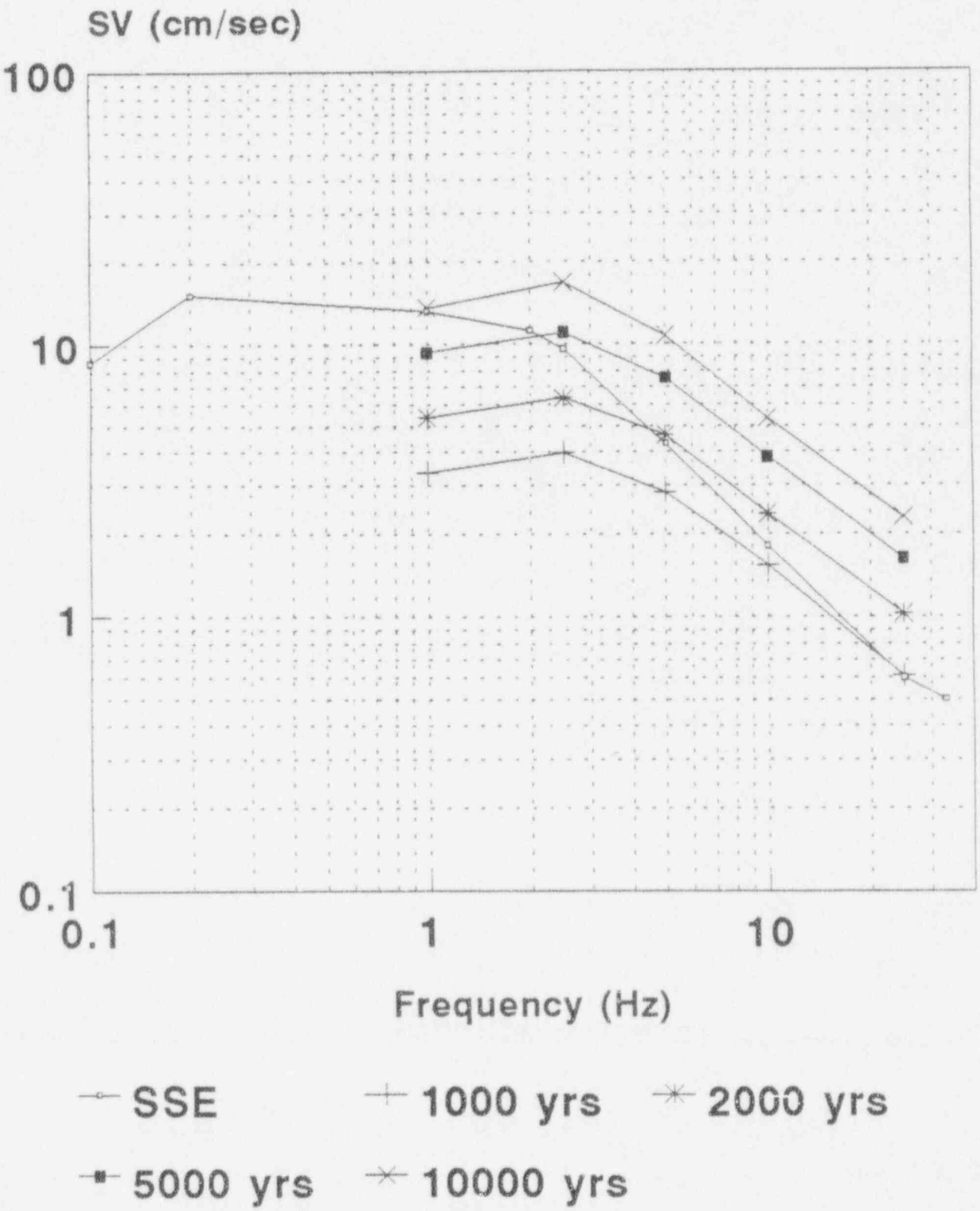


Deep Soil

OCONEE

Horizontal Spectra - 5% Damping

SSE (0.10g - Housner) vs 1993 LLNL Mean Estimates

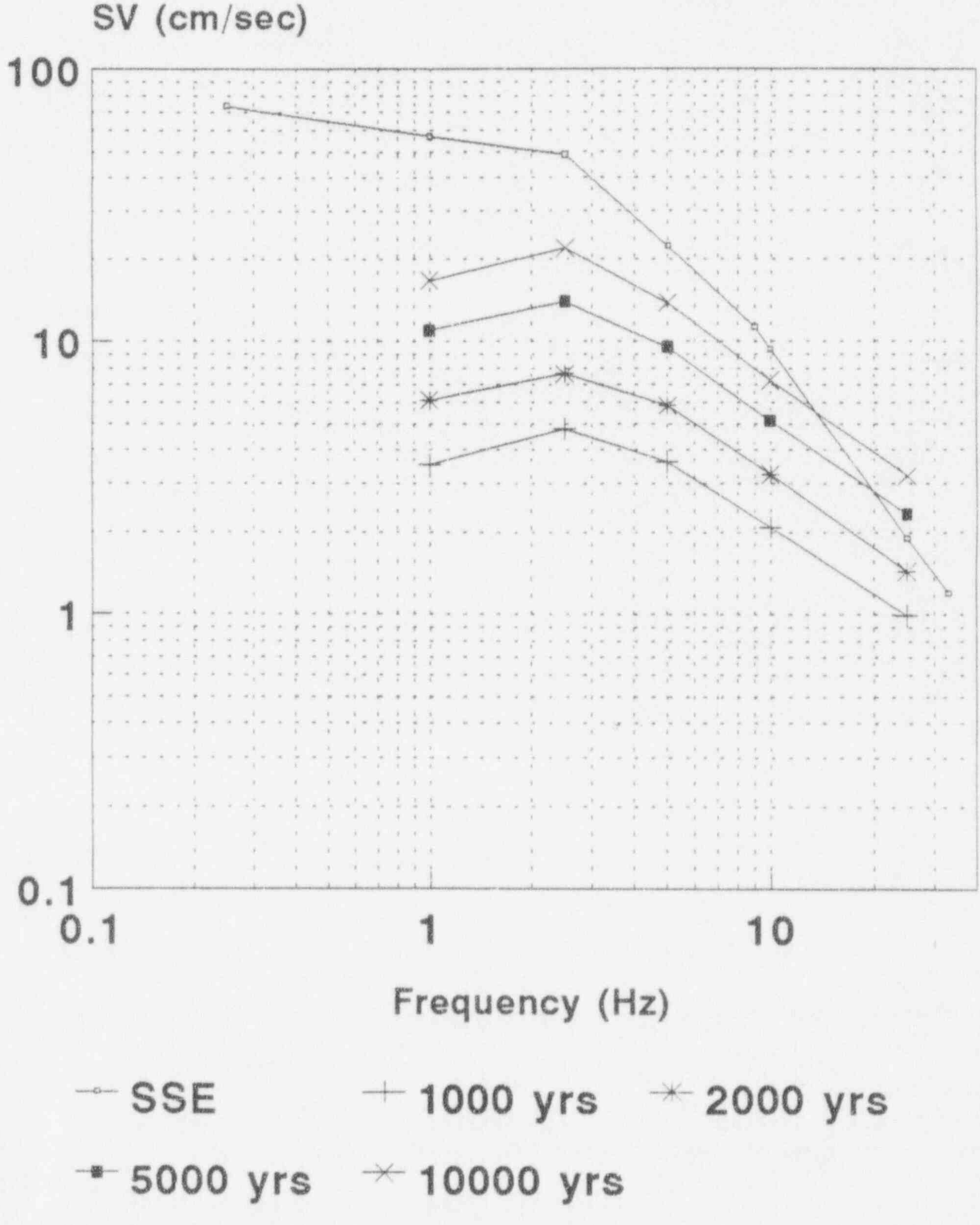


Rock

SEABROOK

Horizontal Spectra - 5% Damping

SSE (0.25g - RG 1.60) vs 1993 LLNL Mean Estimates



Rock