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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

MEETING OF THE SUBCOMMITTEE ON PLANT LICENSE RENEWAL

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TUESDAY,

JUNE 5, 2007

The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 10:30 a.m., Dr. Mario Bonaca, Chairman, presiding.

MEMBERS PRESENT:

MARIO BONACA Chair
WILLIAM J. SHACK
J. SAM ARMIJO
SAID ABDEL-KHALIK
OTTO MAYNARD
JOHN BARTON

ACRS STAFF PRESENT:

MICHAEL JUNGE Designated Federal Officer

NRC STAFF PRESENT:

P.T. KUO

MICHAEL MODES

RICHARD CONTE

JONATHAN ROWLEY

LAMBROSE LOIS

JIM MEDOFF

ROBERT HSU

DUK NGUYEN

ALSO PRESENT:

TED SULLIVAN

JOHN DREYFUSS

PAUL JOHNSON

NORM RADEMACHER

DAVE MANNAI

ALAN COX

MIKE METELL

JIM FITZPATRICK

TED UNDERKOFFLER

LARRY LUKENS

JOHN McCANN

ALSO PRESENT: (CONT.)

JAY THAYER

SCOTT GOODWIN

JOHN HOFFMAN

DAVE LACH

GARRY YOUNG

MIKE STROUD

REZA AHRABIA

TED IVY

A-G-E-N-D-A

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

10:28 a.m.

CHAIRMAN BONACA: Good morning. The meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. I'm Mario Bonaca, Chairman of the Plant License Renewal Subcommittee for this plant.

ACRS members in attendance are William Shack, Otto Maynard, Said Abdel-Khalik, Sam Armijo, and John Barton. Michael Junge, of the ACRS Staff is the Designated Federal Official for this meeting.

The purpose of this meeting is to review the license renewal application for the Vermont Yankee Nuclear Power Station, the draft SER, and associated documents.

We will hear presentations from representatives of the Office of Nuclear Reactor Regulation, NRR, the Region 1 office, and Entergy Nuclear Operations, Incorporated.

The subcommittee will gather information, analyze relevant issues and facts, and formulate proposed position and action as appropriate for deliberation by the full committee.

Rules of participation in today's meeting were announced as part of the notice of the meeting previously published in the Federal Register. We have received no requests for time to make oral statements, and we have received no written comments from members of the public regarding today's meeting.

A transcript of the meeting is being kept, and will be made available as stated in the Federal Register notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee. Participants should first identify themselves, and speak with sufficient clarity and volume so that they can be readily heard.

We will now proceed with the meeting, and before I call upon Dr. Kuo, of the Office of Nuclear Regulation, to begin I would like to make a couple of general observations regarding this application.

The first is really a recurrent theme, I guess, and the question regarding GALL, and one thing what we notice is that there is an increasing number of exceptions being taken on the GALL, and this is not an issue only for Vermont Yankee. We've seen it coming, and I have raised a number of questions in the past regarding whether or not GALL should be updated to be less descriptive, and to incorporate some of this that are really not exceptions, they are just alternatives. For example, in some cases to ASME code on the report, and to have their views regarding, you know, how do we reduce the number of exceptions being taken. I mean, GALL was originally a cooperative effort between the industry and the staff, to see that there is, you know, 70 percent of the programs take exceptions from GALL says something that has to be looked at.

The second issue I would like to raise is the one of the audit report. The audit report is growing, and it's becoming almost a duplicate of the portion of the SER, but it's not written the same way. So, a reviewer, like the ACRS members, is puzzled by, you know, what information is there in one that is not in the other. Typically, there is none, but in some cases there is. So, you know, is there any way in which that two things can be meshed together and become one document only in the future.

So, these are the two issues I would like to raise, and again, the first one that I talked about may be significant enough to deserve a meeting at some point in the future, because it's not specific to Vermont Yankee, it's more generic to GALL.

MR. KUO: Thank you, Dr. Bonaca.

I'm P.T. Kuo, the Director of the Division of License Renewal.

Your observation is actually very correct, and very on the point. We have observed this same phenomena also, and in the past that's why we tried to update GALL, and in 2005 we updated GALL. The hope was that we would be able to eliminate many of the exceptions that we have -- you have been talking about.

And recently, in a couple of the most recent reviews, we find that, again, there were a lot of exceptions, more than what we would like to see.

So, this is the one thing that we are working on that. We will be working with the industry. We will actually bring this very subject to the industry and see if there's any ways that we can reduce the number of exceptions.

With the number of exceptions we see right now, it doesn't make sense anymore to have the GALL report there with the program, and then, you know, everybody is taking exceptions, and then why -- there's no reason for the GALL to exist anymore.

CHAIRMAN BONACA: For example, on the containment issue, if I remember, there is a statement that says exceptions are so many that there was no point in listing them, otherwise it would have been confusing. Therefore, there is a description of the problem separate from GALL.

So, that, to me, was a clear indication we had to talk about where GALL is going.

MR. KUO: Yes, I fully agree with that assessment, and like I said we plan to work with the industry, and at some point we will come back to the committee and give you a status report on this.

As far as the audit report, I think we have come back to the committee about, I forget how long ago, about a few months ago. We told you that we are going to change from writing the 700 or 800 page report to what we call database.

What the database is, really, is something that when we go to the -- when the audit team goes to the site and audits the on-site design basis document, the applicant will create a question and answer database, and this database is evolving during the audit, so it’s changing. Whenever we have a question, they have an answer, and that database has got to be revised.

But, at the end of the audit, we expect the applicant to submit this database, question and answers, to us, and their information, that becomes a formal document. Okay.

Then, the staff will take that database and build on it to actually provide a write-up similar to SER, basically, providing technical justification to the database and the status, whether it is still under discussion, open, or closed.

So, we are going to build, if you will, an audit report on the question and answer database submitted to us, and then provide the write-up on the technical justifications, and every time we will indicate what the status of that is.

So, that becomes, actually, the main body of the future audit report.

At the end of audit, okay, when everybody is ready to close out the audit status, then we will put a very simple description on top of this database, and then that becomes the audit report.

CHAIRMAN BONACA: Thank you, appreciate the explanation.

MR. KUO: So, that's what we are doing right now.

CHAIRMAN BONACA: Thank you. Okay.

So, I'll turn the meeting over to you, Dr. Kuo, for the Vermont Yankee application.

MISS KIMBALL: Well, yes, we have completed our safety evaluation, and we have an issue there to report to you. About a month ago, you have it in your hand, and I believe in that safety evaluation report we have the four confirmatory items that is, basically, about the boundary of the non-safety-related structures over safety-related structures. Okay. We were -- because of the spatial relationship, we have asked our regional staff to help us to walk down the plant, and so that they can have a better assessment of that.

We haven't been able to get input from the region yet, but this is something that we are going to have it, so we make it the confirmatory item in the report. As soon as we get input from the region, we will be able to hopefully close that out.

Recently, it has caught our attention about a dam, their own dam, and that, the issue, it was closed in the SER, but we noticed lately that this dam was owned by Trans-Canada, and because of the different ownership there is a question who is really responsible for the management of the dam. Okay. So, we have some ongoing discussion with the applicant, and I'm sure today they will address that, too. So that, we think, is resolved, but we will treat it as a confirmed item, too, so that is a new item added to the original SER that you had.

And, that is, really, the review status right now. Right now I'm turning to the applicant to make their application, and then the staff presentation will follow.

With that, I turn to the applicant.

MR. SULLIVAN: Good morning, I'm Ted Sullivan, I'm the 2nd Vice President for Vermont Yankee, and I'd like to thank the ACRS for allowing us to present the license renewal application here today.

I'd like to introduce John Dreyfuss. John is the Director of Nuclear Safety Assurance at Vermont Yankee, and he'll be lead presenter today, and I'd like the Vermont team to introduce themselves, and then I'll turn it directly over to John to make the presentation.

Thank you.

MR. RADEMACHER: Norm Rademacher, I'm the Director of Engineering.

MR. MANNAI: Dave Mannai, Entergy Vermont Yankee Licensing Manager.

MR. COX: I'm Alan Cox with the Entergy License Renewal Team.

MR. METELL: Mike Metell, Vermont Yankee License Renewal Project Manager.

MR. FITZPATRICK: Jim Fitzpatrick, Vermont

Yankee Design Engineering & Civil Structural Group.

MR. UNDERKOFFLER: Ted Underkoffler, I'm a Co-Program Engineer, I am the responsible individual for the Section 11 Containment Inspection Program.

MR. LUKENS: Larry Lukens, Vermont Yankee in Programs and Components Engineering Department. I'm the Supervisor of Code Programs.

MR. McCANN: Good morning. My name is John McCann. I'm the Director of Licensing for the Entergy Fleet.

MR. THAYER: I'm Jay Thayer, I'm Vice President of Operations for Entergy Nuclear. I'm on loan to the Nuclear Energy Institute.

MR. GOODWIN: Good morning. I'm Scott Goodwin, Entergy Design --

CHAIRMAN BONACA: You are going to have to come to a microphone if we are going to go around the room.

MR. GOODWIN: Good morning. I'm Scott Goodwin, Entergy Vermont Yankee Design Engineer and Civil Structural Supervisor.

MR. HOFFMAN: Good morning. My name is John Hoffman. I'm currently retired from Entergy. I was the previous Site License Renewal Project Manager.

MR. LACH: Good morning. My name is Dave

Lach. I'm the Entergy Corporate License Renewal Services Project Manager for the VY License Renewal Project.

MR. YOUNG: I'm Gary Young with Entergy, and I'm the Manager of the License Renewal Group for Entergy.

MR. STROUD: My name is Mike Stroud with the Entergy Corporate Group for License Renewal, and I am the Electrical Lead for Electrical Programs and Review.

MR. AHRABIA: My name Reza Ahrabia, I'm the SI, Civil Structural Lead for License Renewal.

MR. IVY: And, my name is Ted Ivy, I'm with the Entergy Corporate License Renewal Services Group. I'm the Mechanical Lead.

MR. JOHNSON: I'm Paul Johnson at Vermont Yankee. I'm Electrical Design Engineer.

MR. DREYFUSS: All right.

MEMBER BARTON: I'm glad you left somebody there behind to run the plant. I was getting a little nervous about that.

MR. DREYFUSS: Gentlemen, good morning, John Dreyfuss, Director of Nuclear Safety Assurance for Vermont Yankee. I'm responsible for, among other things, the Regulatory, Compliance and Licensing

Group. I'm also the Project Sponsor for the License Renewal Project for Vermont Yankee.

Where we are at right now, and we'll talk about it a little bit as we go through recent plan performance and current plan status, but we are, as we speak, turning the moats switch after a refuel outage, and we are going to plant start up.

So, we appreciate being here, thank you for entertaining us here at the ACRS meeting.

I did want to point out a couple of quick features here. Here's the Connecticut River. Here's the plant. There's the stack back here. We have the intake and the discharge. I think what you'll find is that the plant has been very well maintained over the years. We will talk about some of the capital improvements that we have been making to the plant over the years, in accordance with our long-range plan, and a big investment by Entergy in the plant over the last several cycles. We'll talk about that as well.

We've done the introductions.

Agenda is, we'll talk a little bit about the site description, touch on licensing history and some of the big plant improvements that we have made recently and over the years. We'll talk about recent plant performance and the project itself and team composition. We'll also discuss the cost beneficial severe accident management alternatives that we identified during the course of license renewal. None of them are age related, but they are interesting to speak about.

Additionally, we have a number of presentation topics we've prepared for you on the containment integrity, both the dry well and torus shell, and as P.T. Kuo mentioned, we will also discuss the Vernon Hydroelectric Station.

One thing that we have done is in these presentations we have put together an awful lot of detail, and we also have some hyperlinks and back-up slides. If at any point you want more information, we can provide that for you. If you have seen enough in the way of information, please say so, we will move on to any topic that interests you.

And, of course, we'll entertain any questions that you have during the course of the presentation here.

Site description, the plan is a 125-acre site on the banks of the Connecticut River. It's a very lovely site. General Electric was the NSSS vendor, and Ebasco was the AE and builder of the plant. It is a BWR, Mark I containment. We'll be discussing that a bit during the course of the presentations here today.

The plant is now rated at 1912, 1912 megawatts thermal, with a 650 megawatt electric output.

MEMBER BARTON: Is that original, or is that an upgrade?

MR. DREYFUSS: That is, during the past cycle we implemented a power uprate. We had put the modifications in over the prior two cycles, and in March of this year got the license up -- I'm sorry, 2006, got the license to do the 20 percent uprate.

MEMBER BARTON: Thank you.

MR. DREYFUSS: Very good.

The cooling is a hybrid cycle condenser with forced draft cooling, cooling towers. You saw a little bit of the cooling towers, we have a better shot of that later as well in the presentation slides, and we are currently at a staff of 650 people. That includes our contractors of supplemental work force.

Here are some of the licensing highlights. The plant did go on line in 1972, in March. The expiration of the operating license is March 21, 2012. Thus, we are here.

I did want to point out, in July of 2002 the plant was acquired by Entergy from Vermont Yankee Nuclear Power Corporation, and that really marked the beginning of a number of substantial capital upgrades and major projects, the power uprate project that we talked about, the 20 percent power uprate, dry fuel storage on site at the facility, as well as the License Renewal Project kicked off after Entergy acquired the plant.

I'll go through some of the major plant improvements that we've had. We did replace core spray piping back in 1978. We did the full bevy of modifications to the Mark I containment in the '78 to '82 time frame, new saddles, the hold downs, the shortening of the downcomers to alleviate some of the Mark I containment loading. All of that work was done during that period of time.

In 1986, we replaced our recirc piping with low carbon steel, 316 low carbon steel.

In 1998, we put in our new suction strainers, resulting as a result of some of the industry operating experience that was out there. We also took that opportunity to recoat our torus. We'll be talking about that a little bit later in the presentation as well.

2001, we applied noble chemistry for the first time at the plant, successful application. We most recently reapplied or put our second application on in the past refueling outage. Again, a successful application. And, we've also gone to hydrogen water chemistry, and, of course, those two in combination really do provide for the asset protection and IGSCC mitigation.

MEMBER BARTON: What's your hydrogen water chemistry designed to protect? I mean, how much -- you know, it can vary on the amount of hydrogen depending on what you are trying to protect in the core internals. What are you trying to protect?

MR. DREYFUSS: We protect the full asset and the recirc loop as well.

MEMBER ARMIJO: How do you monitor that? Do you have online ECP monitoring, or just do it --

MR. RADEMACHER: This is Norm Rademacher.

Yes, we do have an online ECP monitor, and we just -- as a matter of fact, as a result of this outage we put in a new one just for ongoing cycling.

MEMBER SHACK: What fraction of the cycle is it operable for?

MR. RADEMACHER: We are also investigating other alternatives to the General Electric supplied

ECP monitor, to improve the reliability.

MR. DREYFUSS: We have had them fail after two months of operation. We have replaced them as well. We've had them work for quite a while, and we are working, as Norm said, on doing an upgrade.

MEMBER BARTON: What's your success rate with operation of hydrogen water chemistry as a system, 95 percent of the time? How much?

MR. RADEMACHER: 98 percent.

MEMBER BARTON: 98 percent of the time?

MR. RADEMACHER: That's correct.

MEMBER BARTON: Okay, good.

Thank you.

MR. ARMIJO: This is maybe a little bit off base, but have you made any adjustment in your hydrogen water chemistry when you went from 100 percent to 120 percent --

MR. DREYFUSS: Yes.

MR. ARMIJO: -- or did you notice an ECP change?

MR. DREYFUSS: Originally, at the previous license conditioning, we were running about 3 SCFM and now we are on a 3.5.

MR. ARMIJO: Okay.

MR. DREYFUSS: Not a substantial change.

This is not necessarily in the slide that you have in front of you, but we thought it was worthwhile to mention. We did implement zinc injection at Vermont Yankee during this past cycle.

And, as far as power uprate, equipment upgrades, I did want to talk some about that. Can we go to the hyperlink there?

MR. ARMIJO: Before you go to that, you didn't do zinc injection earlier, but you used to have a brass condenser. Do you still have brass condensers?

MR. DREYFUSS: That's correct. We have the Admiralty brass condenser, and there is some natural zinc that we do get as a result of the condenser that we have.

MR. ARMIJO: But, you still keep the Admiralty brass condenser, or have you changed that?

MR. DREYFUSS: We have not changed that, that's correct.

MR. ARMIJO: Okay.

MR. RADEMACHER: It is in our long-range plan after 2010 to change that up.

MR. ARMIJO: That would be titanium or --

MR. RADEMACHER: We haven't made the selection of materials at this time.

MR. ARMIJO: Okay.

MR. DREYFUSS: I did want to touch on some of the major equipment changes that we made that we believe position us well for extended operation and good plant reliability into that period.

We did a change out of the high pressure turbine, the LP turbines were replaced earlier, prior to our power uprate, not associated with the power uprate, so that train is all new.

MEMBER BARTON: Was that the rotor cracking issue?

MR. DREYFUSS: No.

MEMBER BARTON: Okay.

MR. DREYFUSS: No, we had a rotor -- we had a rotor insulation issue.

MEMBER BARTON: Okay.

MR. DREYFUSS: And, we did fully reinsulate the rotor to enable us to stay away from any kind of thermal sensitivity and vibration on the power train.

MEMBER BARTON: All right.

MR. DREYFUSS: We additionally replaced, rewound the stader. That’s all new copper, and reinsulated the boiler as well.

Feedwater heaters, we do have new high

pressure feedwater heaters. We had replaced the LP heaters in cycles previous to the power uprate modifications.

Switchyard improvements, we, essentially, replaced the switchyard. We put in lots of new protective features and redundant protection schemes. All of the 345, 3-4-5 KV breakers, are new. That was not driven by uprate, that was driven by our long-range plan as well.

We replaced a number of control systems, feedwater, level control, the feedwater heater level control system. The reactor pressure regulator has gone to digital. We are digital on most of these control systems, and they are working very fine for us.

And, one of the other big challenges that we had in going to power uprate was, we went from two feed pump operation with one in standby, to three feed pump operation, and we had to make a number of modifications to be able to address in the event that we would lose a condensate pump, what would happen to the feedwater system, and this was an area of interest during the power uprate proceedings. So, we put in modifications to provide for auto tripping of a feedwater pump in the event of a trip of a condensate pump. Also, an automatic runback of our recirc system, to maintain power, and additionally, a level setdown, ultimately, very well analyzed and our goal was, one, ensure, primarily, that we would maintain feedwater flow to the reactor vessel, and that we would not have an inadvertent scram on low level or a high level trip on the turbine.

MEMBER BARTON: On the loss of feedwater pump you runback or scram?

MR. DREYFUSS: Correct, loss of feedwater pump will do a runback.

MEMBER BARTON: Runback.

MR. DREYFUSS: Right, and we did an analysis using some sophisticated modeling. Ultimately --

MEMBER ABDEL-KHALIK: What did you do to the condenser? You didn’t say.

MR. DREYFUSS: To the condenser, we did some reinforcement in staking to avert any issues that we might have with vibration, due to the higher flows. We did take a look at the condenser this refuel outage, and we see no issues with the condenser, as a result of the power uprate.

This shows here, up top there is Wayne Manning, one of our operator, as we did reach the new power level. The slide below there, or the picture below, is our Power Ascension Control Center. We did a deliberate slow power ascension, never going backwards, but methodical step by step changes in power, at small increments, analyzed. At the very end here we did a big integrated plant test, where we actually did manually trip one of the condensate pumps and this is the Power Ascension Control Center, the brain of the power ascension operation, and all of us sitting around watching the traces and transients.

If you are astute, you can see that the rods remain out, and these are the traces here. Let's go to that next slide. This was a really nice result. W e had great results from this transient test. Classic quarter wave dampening on level, you can see the tripping of a pump here, and the tripping of the feed pump as far as the changes in feedwater flow, and this test matched perfectly with our analyzed projections for the test. So, a testament to, I think, the engineering staff for the work that they did in analyzing for this transient as well.

MEMBER SHACK: And, your secondary system piping, has much of that been replaced, or is it still all carbon steel?

MR. DREYFUSS: Go ahead, Norm.

MR. RADEMACHER: A lot of the high usage areas, drains and such where they go back to the condenser is chrome-moly. That was the original design.

MEMBER SHACK: Oh, the original design.

MR. RADEMACHER: And so, we haven't had to replace much of that.

MR. DREYFUSS: As far as recent plant performance, current plan performance, current plan status right now is, we are mode switch to start-up. We will be withdrawing control rods for start-up from our refueling outage.

Cycle 25, where we did the 20 percent power uprate, was a 549-day safe, continuous run. We had shut down for our prior refueling outage, did all of the maintenance, did some additional power uprate modifications, started the plant up, and it maintained -- we maintained it in service during the cycle, as well as doing the power uprate and power increase during the wave. So, a good, safe run, and a testament to the quality of the work that was done.

We started our refuel outage on May 12, 2007. Safe shutdown from that outage. We are starting up as we speak.

And, for key outage summary, one thing

that I did want to say, as far as the power uprate went, we were a full year operation at the extended uprate level with no challenges to the operators and good, safe performance of the unit.

A couple of key things as far the outage summary goes, some of the big things that we got done is, we did replace one of our large feedwater motors, the size of a walk-in kitchen, I would characterize it, pretty good size motor. That worked well, and it was fine. We did replace the last of the 345 KV breakers that we were seeking to replace. Again, that was driven by our long-range plan. We have a 15-year capital plan, and we have a large motor program, we are replacing and refurbishing motors as we go, and laying them out in a logical sequence based on priority.

MEMBER BARTON: Does that include your recirc motors as well?

MR. DREYFUSS: We are looking at the recirc motors as well, and that's a relatively high priority one for us as well. It's a big job.

MEMBER BARTON: Yes.

MR. DREYFUSS: The feedwater motor was a big job, had to cut a hole in the turbine building, cut a hole in the turbine building floor --

MEMBER BARTON: Roof, yes.

MR. DREYFUSS: -- it was a big deal, but very well done.

Service water, we replaced the discharge valve and check valve on our service water D train, our delta train of service water. Again, that was work that we are looking to do. We have the other trains laid out in our long-range plan that we'll be doing over the course of the next several years.

We did replace a HPCI high pressure cooling injection turbine exhaust and check valve, that we had had some history with leak rating. We put a new check valve in, it's working beautifully.

So, some of the highlights from the outage.

MEMBER ABDEL-KHALIK: Now, you've been operating with a MELLLA power flow limit line?

MR. DREYFUSS: We are, we are operating under the MELLLA operating regime, and we are -- we did some gamma scanning for this refuel outage in support of the GE application for the MELLLA+.

MEMBER ABDEL-KHALIK: And, your operators have had no problems operating with MELLLA in terms of the range of control that they have?

MR. DREYFUSS: That's correct. There

have been no problems. Ideally, the MELLLA+ will provide some additional operational flexibility, so that we have a larger flow window, in particular, end-of-cycle, so that we don't have to make as many pattern adjustments to the --

CHAIRMAN BONACA: You say a larger flow window, I mean, you have some flow window now?

MR. DREYFUSS: Yes.

CHAIRMAN BONACA: With the MELLLA?

MR. MANNAI: Yes, this is Dave Mannai, we have about a 4 to 5 percent flow window. It's a little bit larger than Brunswick's. We did some industry comparisons with them when we were going to implement uprate, and I'm pleased to report that over the last cycle we had a number of rod adjustments toward the end of the cycle, you know, as is typical, but not having MELLLA+ at a full EPU condition we did have to do more rod adjustments, but they are all done safely with excellent focus on reactivity management and performance. We had no issues as a result of that.

MEMBER ABDEL-KHALIK: And, you can enter into higher than 100 percent flow range?

MR. MANNAI: Yes, we implemented increased core flow back in late '99, early 2000 time frame, and we went -- you know, we had the full 107 percent increase core flow. As you implement power uprate you lose some of that margin, so we went from 107 percent down to about 104.5, so our flow window is from 99 percent to, roughly, 104.5 percent flow, so we had a little bit more margin than one of the Brunswick units.

MEMBER ABDEL-KHALIK: Thank you.

MR. DREYFUSS: As far as an overall summary, excellent plant material condition. We did do a lot of looking as a result of a power uprate and the changes that we had made, and we found the plant to be in excellent health. We'll talk a little bit more about that.

We did not identify any significant equipment issues, routine items, routine added out of scope, and well managed and addressed. No generic issues.

Outage items of interest, a lot of interest from everybody on the steam dryer and its performance, as well as the performance of flow accelerated corrosion under the uprate power levels. I'd like to talk a little bit about both of those topics as well.

MEMBER MAYNARD: You said you are going to talk more about your first bullet there, excellent plant material condition?

MR. DREYFUSS: Yes, sir.

MEMBER MAYNARD: Okay, because that's an easy -- that's a statement to make, but it doesn't really give me a feel. You obviously have some issues and some things that you are dealing with, I'd like to get a feel for kind of what level of items that you do have on your list of things to do.

MR. DREYFUSS: All right, very good, thank you.

As far as the steam dryer went, during start up from the last refuel outage we did do extensive monitoring of the steam dryer to validate that we are going to remain within the low profile, code low profiles, and we did do that.

But also, during the course of the cycle we did online monitoring to a high degree. Additionally, during this last outage, lots of interest in terms of the steam dryer condition as we pulled it out of the vessel.

So, from an online monitoring standpoint, we have been monitoring, we saw no changes in reactor water level that we couldn't explain. Similarly, steam dome pressure, no changes there that would prompt us or kick us into any off-normal procedure that we have for actual steam dryer issues.

Additionally, we do monitor moisture carryover, and we had no unexplained changes with moisture carryover. It tracked as predicted, with changes in power or changes in rod sequences, which, again, those were all anticipated.

MEMBER ABDEL-KHALIK: How is that measured?

MR. DREYFUSS: We use -- Norm, can you speak to this?

MR. RADEMACHER: Sure. We use sodium-24 testing. The chemistry performs the testing, and use a radioactive sample and verify. And, they do on a weekly basis, and we monitor statistically and see if there's any statistic changes, statistically unusual changes, every week.

And, the performance of that has been -- you could see the change with our uprate, as we increased steam flow you get more carryover, but then it stays relatively constant through the rest of the year for the cycle.

MR. DREYFUSS: It probably averages about .12 percent.

MEMBER ABDEL-KHALIK: And, the uncertainty in that is how much?

MR. RADEMACHER: I don't know the answer to that question.

MR. MANNAI: We'll get that information and get back to you.

MR. DREYFUSS: It's very predictable. We'll get the numbers on the uncertainty for you.

For outage monitoring as well, we did take a look and found that there were no fatigue indications that have been seen elsewhere in the industry. I happened to be at one facility when they removed the dryer from the reactor vessel, and there were obvious flaws in that steam dryer, in particular, some of the areas where reinforcement and strengthening modifications were made. We took a look at all of those areas, and the steam dryer looks -- there were no indications, and the steam dryer is in very good health.

MEMBER BARTON: Are there any cracks at all in your steam dryer?

MR. DREYFUSS: There were some indications that we identified as well. We'll talk a little bit about that. We characterized them as IGSCC as well --

MEMBER BARTON: Okay.

MR. DREYFUSS: -- and dispositioned them

with General Electric as use as is. I'll explain some of those as well as we go forward.

MEMBER BARTON: All right, thank you.

MR. DREYFUSS: Go to the hyperlink here. This is a shot of the steam dryer here, and we did find -- these are the lifting lugs for the steam dryer. We found that on a tap weld on two of these lifting lugs, there's a structural weld underneath here, that was fine, but the tack weld, that's, essentially, anti-rotation for the lifting lugs, we did find a couple of small indications there, and they may be service-induced from lifting, lifting the dryer.

Where we did find IGSCC is, this shows here, we have two steam dams, and they are about half an inch wide, 12 feet long, six inches high, and during the visual inspection, we did very high-quality visual inspections of this outage as well as last outage, we saw three indications right along one edge of the steam dam. They didn't turn the corner whatsoever, and they look like classic IGSCC-type indications, dispositioned as use as is. We concurred with that in our Civil Structural Group, and we will inspect them next outage.

CHAIRMAN BONACA: You didn't see them in

the previous outage?

MR. DREYFUSS: We did not see them in the previous outage.

CHAIRMAN BONACA: So, this is indications that developed over this period of operation.

MR. DREYFUSS: That's correct. What we had done, in 2004, two cycles ago, is we did do some strengthening modifications here, some weld build up at this particular area, as well as putting in a couple of gussets along the length of the steam dam to improve its strength, and we found that in the heat affected zone, where we did that work, that's where the IGSCC showed up.

MR. ARMIJO: So, you believe it's residual stress from your welding that caused the cracking to initiate there?

MR. DREYFUSS: Yes, sir.

MR. ARMIJO: Do you have any micro structural confirmation that it was IGSCC and not something else?

MR. DREYFUSS: No.

MR. ARMIJO: So, it's just -- is there water up there? How can you have a cracking in a steam dryer? Is there liquid bays up there?

MR. MANNAI: A fraction of a percent.

MR. LUKENS: It's very low moisture content at that part of the dryer.

MR. ARMIJO: But, there was no metallographic sample taken to verify its intergranulars?

MR. DREYFUSS: That is correct.

MR. ARMIJO: So, it's an indication, and you concluded with G.E. that it was IGSCC.

MR. DREYFUSS: Right, and we will again look at it next outage to confirm that.

MEMBER MAYNARD: Can you explain to me what you mean by a very high-quality visual inspection?

MR. DREYFUSS: Yes, the standard that we used was G.E. SIL, Service Information Letter 644 requires visual examination. The technology that was used, the cameras that were used, the speed at which the cameras moved, the clarity of the water was very high as well.

MR. RADEMACHER: And the lighting.

MR. DREYFUSS: And the lighting was very good.

MR. RADEMACHER: It was almost EVT -- met EVT standards, the enhanced visual requirements.

MEMBER SHACK: Now, how do you disposition this curve -- crack? You know, what's the process?

What's the acceptance criteria for the dispositioning?

MR. RADEMACHER: General Electric evaluates it. Well, first off, just to remind you, this is on the end of the steam dam, it's a ½ inch wide, just on the face of the steam dam.

Then they evaluate the condition, where it is, and whether it impacts the structural capability of the steam dryer, and then they provide a response to us that is reviewed by our structural folks to verify that it's acceptable.

And --

Larry, do you have anything to add to that?

MR. LUKENS: This is Larry Lukens.

We spent a lot of time on the phone with General Electric, both their metallurgist and their analysis folks, on this particular set of indications, and the cracks are consistent with IGSCC. The history on this particular spot in the dryer is that in 2004 there were a number of welds that were put on because of cracks found in structural parts in the vicinity of that steam dam.

This particular spot in the steam dam is not a structural part of the steam dam. It's about a 3-inch high piece of this 6-inch stainless plate, and these cracks are characteristic of stress relief. And, in 2004, when the original indications in these areas -- this area was identified, there was a lot of discussion in that analysis about the stress induced by the welding, by the original manufacturing process.

There are four symmetrical locations to this specific spot, and only one of the four has these indications.

MR. ARMIJO: So, G.E. dispositioned that by saying, and correct me if I'm not saying what they told you, but these cracks were caused by residual fabrication stresses caused by the welding.

MR. LUKENS: That's correct.

MR. ARMIJO: And, they must have assessed that these cracks wouldn't propagate and leave you with a loose part.

MR. LUKENS: That was our big concern, yes.

MR. ARMIJO: Okay, and that's been reviewed with the staff.

MR. LUKENS: No, the staff --

MR. DREYFUSS: Well, we did do a -- we had a telecon with Tom Scarborough and a number of the consultants that were involved in the steam dryer work, as a courtesy call, and did explain to them what we saw and what we had identified as well.

MR. RADEMACHER: And, in addition, we forwarded our detailed report to the staff for their review, as part of our license conditions, after each inspection of the dryer wall, for the next -- this cycle, as well as the next two refueling cycles, we'll be continuing to monitor the steam dryer, and we'll prepare a report for the staff for their review.

MR. LUKENS: That's a 60-day report.

MR. MANNAI: Yes, this is Dave Mannai. I think it's worth noting, we had set up that courtesy teleconference with the NRC staff ahead of time, even before we noted these indications, and we discussed those indications fully with the staff at that telecon, and much of the questions that you are asking now were similar to the questions they asked, and staff, I believe, was satisfied at the end of that teleconference. We owed them the formal reports in accordance with our license condition, 60-day report.

MR. DREYFUSS: And, some of the industry operating experience that we had followed is, there were substantial flaws here along the lower plate, along the gussets and shoes, as well as the gussets pulling away from the actual base plate here. Again, we looked at all of those areas, all of the preemptive strengthening modifications that we had done, and found them to be in good order, no indications there.

MR. RADEMACHER: We performed over 460 inspections, both inside and out, and there was no change in any of the previously identified indications, and just the new ones that we have mentioned during our conversation here today.

MR. DREYFUSS: Any other questions on the steam dryer?

CHAIRMAN BONACA: Just the question I had was, you will inspect again at the end of the new cycle, and for how long do you plan to do inspections?

MR. DREYFUSS: We will follow the SIL-644 guidance. However, we did have a license condition that, rather than every other outage that we would do three successive --

CHAIRMAN BONACA: Yes.

MR. DREYFUSS: -- full inspections of the susceptible, accessible welds. So, this outage and the next two, we will also do the same type of high-quality visual inspection.

CHAIRMAN BONACA: So, the dispositioning was, essentially, for a cycle length, or a disposition that's acceptable for a cycle of operation.

MR. DREYFUSS: That's correct.

CHAIRMAN BONACA: And, they will be

inspected again.

MR. DREYFUSS: Inspect again next cycle, correct.

CHAIRMAN BONACA: Thank you.

MR. RADEMACHER: In addition now, as part of license renewal, we have an ongoing commitment to meet SIL-644 for the license extension period.

MEMBER SHACK: And, it is sort of a rock in a hard place. Every strengthening operation you make to protect against fatigue just gives you a new ISSC location.

MR. DREYFUSS: That was one of the concerns that we had, in terms of the modeling that we did on the steam dryer, to make sure that we had mesh sizes small enough to really get a good understanding of what the stresses were at those key locations. That did prove to have been accurate, and we don't see any indications.

MEMBER SHACK: Now, the fluids is up here low enough, you don't have to worry about helium in the stainless steel?

MR. DREYFUSS: Right, yes.

MEMBER ABDEL-KHALIK: Was the steam pressure monitored during the power uprate to detect any sort of high-frequency variations in steam pressure?

MR. DREYFUSS: Yes, we had highly instrumented both the steam lines, feedwater lines as well, and looked at steam dome pressure, and we monitored any fluctuations there.

What we had learned from the industry is that there were some signals, acoustic signals, that were being brought from the main steam lines back to the steam dryer, that's what we monitored.

MEMBER ABDEL-KHALIK: And, what were the results of those monitoring activities?

MR. DREYFUSS: We stayed well within the loads. We never -- it went as we predicted, and did not approach the ASME loads.

MEMBER ABDEL-KHALIK: And, what were the dominant frequencies?

MR. DREYFUSS: We had a frequency at 137 Hertz, and another one -- and we'll give you the exact numbers, but a little bit -- I think it was 148, 148 Hertz, and they coincided with the SRB branch line connections off the main steam lines. We had predicted we would see a spike there, we did see it there, it grew and then mitigated, and stayed within the limits.

MEMBER ABDEL-KHALIK: Thank you.

MR. DREYFUSS: Okay. Flow accelerated corrosion, this was another area that we paid particular attention to under the uprate conditions. We did increase the number of FAC inspections by 50 percent from what we typically do during outages. We did do 63 inspections overall. They were satisfactory and, in fact, they were consistent with your analytical predictions that we use in our modeling for FAC.

One area that, Jim, maybe you can talk about, the cross-around piping inspection that we did. It's one of the susceptible areas.

MR. FITZPATRICK: We've got one remaining carbon steel cross-around. Jim Fitzpatrick. It's the only thing left in the system that is still susceptible, so we use that as an indicator, and we've been doing visual inspections of that almost every outage. And, it's, essentially, the same condition it was in 1996, even with the power uprate.

We have visual marks on the inside, and they are still there after this cycle.

MEMBER SHACK: Okay, that's how you do the visual, it's still there.

MR. FITZPATRICK: Well, we did UTs, and we have a mat on the inside, and you go inside the pipe and see if it's still there.

MEMBER SHACK: There's no wall thinning.

MR. FITZPATRICK: No, and that's surprising.

MR. LUKENS: This is Larry Lukens, maybe, maybe the gentleman didn't completely understand what you said, there were marks -- marks we put on the inside --

MR. FITZPATRICK: Yes.

MR. LUKENS: -- to make sure that we understood --

MEMBER SHACK: I was sort of wondering how you were going to do the visual, you know.

MR. ARMIJO: Poke in your head.

MR. LUKENS: Actually crawl down the pipe.

MEMBER SHACK: No, but I mean, you have marks, and if they are still there that's an indication you are not losing metal, yes.

MEMBER MAYNARD: The 50 percent increase in number of FAC inspections, is that just the number of inspections, or did you also increase number of locations that you are looking at?

MR. DREYFUSS: Jim?

MR. FITZPATRICK: A mixture of both. We do repeat inspections. We do some new areas, try to mix it up, try to add more areas on the same system, look at the models, get more data for the check-works models we are using.

MR. ARMIJO: Now you used -- you have chrome-moly most here.

MR. FITZPATRICK: In the extraction steam system it's all chrome-moly. The heated drain systems, everything downstream of the local control valves are chrome-moly or stainless, except for the lowest load pressure here.

MEMBER SHACK: Do you have a feel for the amount of margin you have with this material compared to the carbon steel, as far as FAC resistance?

MR. FITZPATRICK: EPRI publishes 34 times more resistant than the carbon.

MEMBER SHACK: Order of magnitude at least, huh?

MR. FITZPATRICK: Well, we are not seeing -- we've done some monitoring in the past 15 years on the chrome-moly and haven't seen anywhere at all.

MEMBER SHACK: And, this is 2-1/4 chrome-1-moly or what?

MR. FITZPATRICK: Some 2-1/4, some 1-1/4, EPRI rec -- even if you have a carbon steel that's got more than .1 percent it works.

CHAIRMAN BONACA: Going back to the 50 percent increase, what was the criteria used? I mean, you looked for still susceptible locations, right?

MR. DREYFUSS: Go ahead, Jim.

MR. FITZPATRICK: Jim Fitzpatrick.

Just for planning, going to the power uprate, we had pretty good confidence in what was going on prior to power uprate, and we figured we'd do 50 percent more inspections to get more data, just to get it back into the check-works models, and then at the end of the three cycles we'll be assessing where to go from there.

We've been on a trend of small in order inspections over time, and most of the industry is, too.

MR. DREYFUSS: Okay, and again, we'll continue to do the increased scope of these inspections for two more cycles.

Now, moving on to the license renewal project itself. As you have heard from introductions, we have a multi-discipline team, a good blend of people from both our Corporate staff, as well as at the site. At the site, we have personnel, not just from the key engineering programs, programs and components and system engineering, design engineering, we also had operations, maintenance and other groups participate, so that we would get that synergy and make sure everybody sees what's coming here with license renewal.

We did, as far as the Revision 1 to the Standard Review Plan in GALL, it's noteworthy that both Pilgrim and VY were the first to go that route, and we are going to talk more about GALL exceptions. I know you are interested in that, but general overall -- over-arching philosophy on the GALL is that we comply with the GALL.

There were a number of areas where there -- I'd characterize them as technical exceptions for the GALL that we needed to take, but we were conservative in the development of the GALL, and I think you'll find that these are relatively minor exceptions, and we'll speak to them in detail as well.

Of course, we incorporated industry lessons learned, both at Pilgrim and other fleet plants that have undergone license renewal, and others in the industry.

As far as the exception types, we have overall 30 exceptions to the GALL. As far as the types of exceptions, you know, for example, if we were committed to a different version of an ASME code, we did take exception to the GALL. So, we've broken down the exceptions that we took into six categories that we'll describe to you, and I'd like to ask Alan Cox to brief you on that.

MR. COX: These six categories -- this is Alan Cox -- the six categories was our -- to try to characterize these exceptions, and you can draw the lines in different places, they are somewhat arbitrary, I guess, and there's some overlap between them. So, there's not a real clear-cut line.

The first category we've got there is where an activity is not applicable to the plant design. That was pretty straightforward. We may have -- I think we took an exception to metal enclosed bus program, where it talked about insulation between phases, we didn't have insulation between phases. In our bus, we had insulation -- or insulators that supported the bus, but we didn't have any insulation between phases.

So, we took, I guess, an overall philosophy on these exceptions, we took a pretty conservative or a literal interpretation of what was in GALL. If it said do an inspection, we did have an inspection, we tended to call that out as an exception. I think if you compare applications from plant to plant you'll see that there's different degrees of that, there's different levels of conservatism or how literal you take things, so you'll see differences in numbers probably because of those factors.

The second category we've got there is an alternative that's consistent with approved methods. I guess one of the other philosophies that we took was, if we had a -- as you know, GALL says that that's one way of doing things, if we had an existing plant program that had proven within the, you know, the circumstances of our plant, our people, our training programs, if that existing program had proven effective over the years in dealing with that aging effect, we didn't make the change in the program just to say that we were consistent with GALL. We felt like it was more important to use what's already in place and what's establish and proven for our plant, for our circumstances.

The third category is programs based on different code --

MEMBER MAYNARD: Excuse me, alternative, consistent with approved methods, from what I understood you to say, I'm not sure what the approved methods are. Is it approved method just because it has worked for you, or is it other things in the regulations that --

MR. COX: In some cases it's -- the most obvious thing that comes to mind is the BWR VIP program. A lot of times you have specifics there that are -- maybe we've got an approved exception to the BWR VIP program because of plant unique circumstances, and we would take that approach.

MR. DREYFUSS: You know, Alan, we have an example that we could go to here.

MR. COX: Right.

This is one that dealt with the frequency, and we had approval of the Generic Letter 89-13, to do things at a refueling frequency, and I think the GALL report may have been more specific than that, it may have said annually. In some cases it was not practical to do it annually, you had the access to the system, you had plans to do things during refueling outages.

MEMBER BARTON: Your refueling outages are how often?

MR. COX: Eighteen months.

MEMBER BARTON: Eighteen months?

MR. COX: Right.

MEMBER BARTON: Okay.

MR. COX: That's an example of that category. Again, there are others. There was, oh, seven or eight examples I think that we had in that category.

The third one, different ASME code edition, that's pretty straightforward. There's been a lot of discussion about that. There's was a handful of things that fell in that category.

Again, this category met the equal to or better than the NUREG 1801 method, that's a little bit of, you know, the second category that we talked about earlier is a little bit of the same thing, but we've got an example of that -- can you click on the example there?

MR. DREYFUSS: Yes, let's look at that.

MR. COX: The GALL analysis program, the GALL program, you know, again, was a program that was developed off of somebody -- some specific plant that was reviewed and accepted. Well, it turns out that that particular plant program had flashpoint testing in there. We have a practice at VY to do a fuel dilution test, which is considered to be a better indicator of the contamination of the lube oil with fuel oil than a flashpoint test. So again, it's an alternative that's equally effective, if not better, than what was in the NUREG, and it's a fairly minor thing, it took pretty little interpretation and decided that that was something we needed to flag as an exception.

MR. DREYFUSS: Okay.

MR. COX: The experience justifies exception.

MEMBER BARTON: That's a scary one.

MR. COX: It really kind of ties back in to the philosophy that we were talking about earlier, where you've got an established program that's been proven effective under the plant specific circumstances that it's applicable to, and just go and click on the example of that, if you will.

Diesel fuel additives is specified in the particular GALL program. At VY, there's a long history of not requiring any additives beyond those which are provided as part of the manufacturing process by the fuel vendor, and we've had very good operating experience with the existing process. We didn't feel like it was appropriate to change that.

MEMBER BARTON: How about -- how about containment leak rate tests ten to 15 years, where did that one come from?

MR. UNDERKOFFLER: We presently -- Ted

Underkoffler -- we presently test containment on a ten-year basis.

MEMBER BARTON: Right.

MR. UNDERKOFFLER: We are right in a five-year extension right now.

MEMBER BARTON: About what?

MR. UNDERKOFFLER: On the analysis of the uprate analysis. We did the extension for five years.

MEMBER BARTON: One time?

MR. UNDERKOFFLER: One time only, and we'll be doing our integrated test in 2010.

MR. DREYFUSS: Go ahead.

MR. COX: I'd say there's only a couple exceptions that we considered in that fifth category.

The final one is the NUREG 1801 method is not feasible, and again, this examples that we had in that category were all related to the BWR VIP program, where the VIP program recognizes that some of the inspections that they called for are not technically feasible at this time, and, you know, they have some allowances in there. Larry could probably speak further to this, but that was -- all three of the items we put into that category were BWR VIP items, where the technology is not there to allow you to do the particular inspection.

MR. LUKENS: This is Larry Lukens.

Probably the classical example of this is the so-called P9 weld and the core spray shroud the collar, the P9 weld is inaccessible, it’s not visible, can’t get there. Several years ago, we got a technique approved by EPRI to interrogate this weld by UT, and that technique was subsequently disqualified because nobody currently believes we can come up with a UT technique to interrogate that weld.

So, that weld is inaccessible, and that weld is redundant to other welds, which we can examine, and which we have examined, we do examine those at the frequency specified by the BWR VIP, so that our inability to examine that weld doesn’t affect structural integrity of the connection, it is an artifact of the way the plant was built, as all BWRs we build.

MEMBER BARTON: I think the concern I’ve got about this whole issue is that there were -- you explained your reasoning for not complying with all the GALL issues, but yet the audit team did find, when you did divert to your own program for whatever reason it was, that you did have to make additional commitments to that program that you were using, even though it wasn’t a GALL program. So, that kind of says, hey, how smart was the NRC team that was there that did the audit that picked these up that made you do -- that you then did agree to do some additional commitments to what you were doing. And, there were several of those in this whole stack of exceptions, and I guess that was the thing that was most concerning to me. Suppose somebody didn't pick this up, and you guys agreed to do additional things to the program you were doing. And, I don't specifically remember which ones they were, but there were a few of those like that.

MR. LUKENS: This is Larry Lukens.

I remember a few of those.

MEMBER BARTON: Yes.

MR. LUKENS: They dealt, in my area they dealt with things like frequency of inspections in fire protection systems.

MEMBER BARTON: Yes, that's one.

MR. LUKENS: And, the intervals that we have used are currently in our TRM, they were derived from -- are the same intervals that used to be in tech specs. They were the intervals that we've used successfully for as long as we've had a fire protection program.

And, we -- our preference would have been not to change those intervals. We were questioned about that, and we decided that it's probably not worth the effort to have the discussion, and decided simply to revise the intervals.

MEMBER BARTON: Right.

MR. DREYFUSS: Hose inspections were an example, I think.

MEMBER BARTON: There were a few of those, yes.

MR. DREYFUSS: That's a good one. We were doing them on an every two year basis, I believe it was, and NFPA requirement was annual.

MEMBER BARTON: Yes. I think a couple of them were in the fire protection area, if I remember.

MR. DREYFUSS: Right.

As far as additional reviews that were done for the license renewal application, we did do a peer review. They've become a standard part of the review.

Additionally, we did both On Site and Off Site Safety Review Committee reviews, had an independent QA review. All of the comments from the internal reviews were, of course, dispositioned and comments resolved prior to our application.

As far as license renewal commitments

goes, and commitment tracking, during the entire course of the license renewal process, and the audits, and the inspections that occurred, as well as our own internal work, we developed, and you'll find the commitments that we would have to make under license renewal.

We tracked them in a fleet program that's been developed. They are using it at Fitzpatrick, as well as Pilgrim. We'll all be using a similar type of program for tracking.

Additionally, we have them tracked in our fleet engineering work tracking program as well, and intend to add them to the final safety analysis report upon issuance of the license.

Aging management programs, we do have 39 aging management programs that we are committing to under the license renewal program. Seventeen of them are in place that don't require changes as reviewed. There are an additional 13 in place that we will be enhancing during this period of license renewal. We have a phased-in approach, again, using fleet initiatives developed, developing fleet standards for these new programs. And additionally, we have nine brand new programs that we've committed to as well.

So again --

CHAIRMAN BONACA: Of the programs you have in place, existing programs, of course, and, you know, you already explained to us the exceptions, which makes sense. The only thing that I hope the message gets to the site, and to the people that, of course, we've seen this in the past, it's important, okay, hopefully, will support the programs of the future, but the plant is getting older, so I'm saying that, you know, I hope that some of the inspections are done aggressively, with the understanding that you've got to look for aging of this plant. I mean, things are going to happen there.

And so, globally, the whole aging management program has to be one that says, you have to be alert to this issue of aging of these plants. I mean, we are really going to walk into uncharted territory. I mean, just, you know -- I didn't see any of the exceptions that you made as being -- as saying we'll stay with the past because it's been good enough, and we don't need to be more aggressive. But still, I'm only saying that that's an important philosophy to instill in the people that manage the aging.

MR. DREYFUSS: And, I appreciate that comment, sir.

CHAIRMAN BONACA: Yes.

MR. DREYFUSS: As we went into license renewal, and even before then, as Entergy came in, and we really got the long-term perspective for a capital plan that went out for 15 years, it was a shift in thinking that we made with our staff, our operators, our mechanics, and our system engineers. And, we did provide some of those key groups training in aging management and the recognition out in the field.

We had a case where we had a control panel wiring that we had seen was oozing some blue goo. The guys went to the EPRI aging management document, the little field book there, and they identified that. We ended up replacing that cable, and it was an aging mechanism that we saw.

So, what's important is to make sure people see that it's important to look forward, get things into a functioning, well-managed, long-range plan, where we prioritize that work, and that is what we are doing. So, we will continue those efforts as well.

MEMBER BARTON: A couple issues on aging management, if you look at your commitments, when you are going to implement?

MR. DREYFUSS: Yes.

MEMBER BARTON: You have the same date, which is when you start your 20-year extension. Now, I don't believe that that's what you are doing, but yet, the paper says that.

MR. DREYFUSS: Right.

MEMBER BARTON: The one-time inspection program you are going to start the day you get the 20-year license. I mean, that's --

MR. DREYFUSS: Right.

MEMBER BARTON: -- I hope you are going to do some one-time inspections before that.

So, I was concerned when I saw that, that you all are going to start everything there, but you didn't -- there was no explanation in the material that said, yes, we are doing this one earlier, we started this one now, but, you know, I guess legally or something we are going to implement it on 2010, or 2012, whatever.

MR. DREYFUSS: Right.

MEMBER BARTON: So, I really don't understand where you are with those programs. For example, you've got the program on -- a new program you've got regarding, what is this one, oh, heat exchange monitoring program.

MR. DREYFUSS: Yes.

MEMBER BARTON: Which you are going to implement that.

But, as I understand, the industry now has programs where you do monitor by water chemistry, heat exchanger conditions, right?

MR. DREYFUSS: Right, yes.

MEMBER BARTON: Because I didn't read anyplace that you were doing that, and I'm saying I hope you are not waiting to 2010 to implement a program that does that right now.

So, it wasn't clear that you guys are doing some of these things now, and you are going to start them in 2012, and it just didn't make a lot of sense to me.

MR. LUKENS: John, could I talk about heat exchangers just briefly? Larry Lukens.

Heat exchangers happen to report to me, too.

We have, over the years we have maintained heat exchangers as part of system engineering, so that individual system engineers were responsible for things like eddy current testing, and heat exchanger cleaning, and performance testing.

MEMBER BARTON: Okay.

MR. LUKENS: The only thing that's new, in terms of heat exchanger monitoring program, is the specific heat exchangers that are listed in the GALL.

MEMBER BARTON: Right.

MR. LUKENS: In fact, we have a heat exchanger program where we have periodic cleaning, we have periodic performance testing, we have periodic eddy current testing. We maintain plugging maps. We maintain plugging margins for all the safety-related heat exchangers.

So, we are doing that now, and there is now a fleet heat exchanger program making the rounds in draft form, that we will be adopting as soon as it's ready to adopt.

MEMBER BARTON: I thought you would be doing that, because there are programs out there now which you are supposed to be implementing. But, you just don't get that from reading this.

MR. COX: Let me add this -- Alan Cox -- let me add one thing to what Larry said.

This program is not all heat exchangers, there's a lot of heat exchangers that Larry has been involved with over the years that are -- that we have programs for 89-13, -- heat exchanger --

MEMBER BARTON: Right.

MR. COX: -- the new program that we're

talking about here is kind of a catch-all of miscellaneous stuff that's not covered by 89-13.

MEMBER BARTON: Right.

MR. COX: That didn't really have a home anywhere else.

MEMBER BARTON: Okay.

MR. COX: So, that's an explanation for that.

MR. RADEMACHER: We have in our corrective action system schedules for each one of the new programs that we're implementing.

MEMBER BARTON: When you are going to implement them.

MR. RADEMACHER: When we are going to implement them.

MEMBER BARTON: Okay.

MR. DREYFUSS: Let's go to the bullet here, go to the hyperlink. What we committed to was prior to the license renewal period, but as a fleet we are taking an approach this way here, and this will work for all of us. We will be phasing in various new and enhanced programs over time, as well as reinforcing the merits of the existing programs as well.

MEMBER BARTON: Thank you.

MR. DREYFUSS: You are welcome.

CHAIRMAN BONACA: This is to allow the varied piping inspection program.

MR. DREYFUSS: I'm sorry?

CHAIRMAN BONACA: Varied piping inspection program? The question I have is, this is an example, where you are committed to perform an inspection in the ten years before the period of extended operation, and then an inspection in the first ten years of the period of extended operation, which means you could go 20 years, or 19 years, between two inspections.

Now, looking at the inspection report we got from the NRC yesterday, it looked like you had an inspection in 2003, actually, okay.

But, the question I have, again, it goes to the, you know, how -- this is a long period of time between inspections. Now, I'm not -- I'm not all excited about digging and going after a pipe knowing that you are going to probably create some problem, but still, you know, how do you interpret the problem in GALL?

MR. RADEMACHER: Dr. Bonaca, let me -- Norm Rademacher -- I just want to let you know that Vermont Yankee had a previous piping program that any time that we would open an underground system that we would go and inspect, take samples, and so forth, and monitor that.

In addition, part of it, this is one of the ones that we had that we are in the process of enhancing, and, for example, during this past outage we did inspections of our alternate cooling system, to our entire service water to the cooling tower, it's all varied pipe, we did a special test to verify that it flowed appropriately, and we did visual inspections.

We normally do those inspections at a refueling outage, so it's -- there are many systems that are on a much higher frequency, and then what we are going to do is enhance them to add the other systems that we have.

CHAIRMAN BONACA: How frequently have you had these opportunistic inspections, roughly, I mean, every two years, every five years? I'm talking about opportunistic inspections.

MR. DREYFUSS: Go ahead.

MR. METELL: Dr. Bonaca, this is Mike Metell, I was the original service water system engineer back in the '80s. We have done quite a bit of investigative work. We've had many opportunities, for example, we built a warehouse which required us to do underground digging. We were able to inspect the pipes at that time.

We also had some other piping that we needed to physically dig up, to get the particular point in time, so we were able to look at the mastics that covered the lining, and it was in outstanding shape. We typically found that, and again, this was in the period of the '80s.

Norm had talked to later periods, and, you know, in 1990-2000, so we've looked at this over the time, it has been opportunistic. There's certainly enhancements we can make to it, but we can tell you now that, again, the mastics that protest the outside of the pipe are in excellent shape, we've done UTs and such.

CHAIRMAN BONACA: So, the answer is really that you are performing opportunistic inspections with quite a frequency.

MR. METELL: Yes.

CHAIRMAN BONACA: Because, I mean, when you look at the application and the SER, you get to the conclusion, since you have no information that you could go as far as 19 years.

Now, I knew that you are digging in much more often than that.

MR. METELL: Yes.

CHAIRMAN BONACA: You know, when you talk about operating experience it would be useful to know that you are doing, in fact you are digging often time, and then this becomes a non-issue.

MR. RADEMACHER: And, for example, another excavation that we had this cycle was, we are putting a new extension to our reactor building for dry fuel storage, and as a result of that we had excavation for fire protection piping, so we did inspections on that.

So, those, as we continue on that's certainly our plan, and then to enhance the program to do it more frequently and incorporate that into the program.

CHAIRMAN BONACA: Thank you.

MEMBER BARTON: Can I ask a question about service water piping? I read in the application -- I forget where it was, that carbon steel unlined would be an aggressive way to attack. I didn't see anyplace that you have a program for monitoring, protecting or doing something with service water piping. What am I missing?

MR. METELL: This is Mike Metell again.

What we have are, there's two types of tack, the aerobic bacteria attack, which make large amounts of material, generally that attack slows down after about three or four years, because after all the areas are occluded and the bacteria can't continue.

We have, over the years, I ended my inspection during the mid '80s, my predecessors have continued that up and have verified, just by casual conversation, indeed, the amount of pipe does not -- you know, pipe loss due to the aerobic bacteria has not increased.

The anaerobes were found small in number, and I think the kinetics on those are due to water temperature. We don't suffer the same problems as many of the southern plants do, because of the warmer weather.

MEMBER BARTON: Right.

MR. METELL: So --

MEMBER BARTON: But, global warming is going to get you, though, global warming is going to get you. This isn't Al Gore.

MR. DREYFUSS: We've got that in the long-range plan.

MEMBER BARTON: Good to hear that, John.

MR. METELL: We do have aerobic bacteria, they over time do penetrate the pipe on just a pin hole, it's happened on the thinner pipes, and our system engineer right now currently is examining that, and in the long-term plan, as John has said, is to look at how we are going to approach that.

You know, you can do replacement that's very difficult to challenge if underground.

MEMBER BARTON: Oh, yes.

MR. METELL: You have the inlays that you can put in, which may work very well for this type of situation, because there's no isolation valves.

MEMBER BARTON: I had the same problem one time, so I just wondered what you guys were doing with it. It sounds like you are monitoring it. Okay.

MR. DREYFUSS: We do have a draft safety evaluation report, it's in hand. We worked very hard, along with the staff, to ensure that we would resolve all of these items and, ultimately, we have no open items on the SER. It is clean. There are -- there were six confirmatory items, it's our understanding that two of them are now resolved, and we are working with the staff to provide some additional clarifying details to ensure that we have satisfactory resolution of the four other items.

It's our understanding that there are no outstanding technical issues associated with these confirmatory items, strictly administrative to get the additional information. These are, specifically, boundary issues, to provide some clarifying details on that.

Cost beneficial, severe accident management alternatives, again, none of them were age related, but this was a really good part of the process where we got to identify some additional things that may improve the ultimate risk profile of the plant. Five of them are procedures related, one of them is a relatively small minor modification. Two of the procedures related ones, to involve us getting as generator.

What we have done is entered all of them into our corrective action program, so that we can prioritize them and review them for implementation in accordance with our long-range plan.

CHAIRMAN BONACA: You have TRA.

MR. DREYFUSS: Yes.

CHAIRMAN BONACA: And, what's the core damage frequency for Vermont Yankee?

MR. DREYFUSS: Do you know the specific number, Mike?

MR. METELL: I do not.

MEMBER SHACK: 8 x 10^{-6}?

MR. DREYFUSS: It's in that 10^{-6} realm.

CHAIRMAN BONACA: That’s only internal events or --

MEMBER SHACK: Yes, they multiply by 3.3 when they do the SAMAS to account for the external events.

CHAIRMAN BONACA: Okay, which is pretty much on line.

MEMBER SHACK: They compare it to the fleet and they are not too far out of line.

CHAIRMAN BONACA: That’s right. Okay.

MR. DREYFUSS: Okay.

MEMBER SHACK: Twenty-five person rem per year for the societal risk.

MEMBER BARTON: Is he ACRS or is working for these guys?

MEMBER SHACK: Thank you.

CHAIRMAN BONACA: Let me say that, you know, around noontime we want to take a break for lunch, and you tell me what is a good place to stop and take a break.

MR. DREYFUSS: We are now at the point where we are ready to go into the formal presentation topics, both drywall shell and core shell. If this is a good time, we can do that.

MEMBER SHACK: Let me ask you just an

interrupted question here, since you are sort of about to change topics.

MR. DREYFUSS: Sure.

MEMBER SHACK: What is the actual condition of your core shroud?

MR. DREYFUSS: We have tie rod repairs to do.

MEMBER SHACK: Now, is that preventative, or you are cracked to -- and you are holding it together with these things?

MR. LUKENS: I'll take that one, Larry Lukens.

That was preventative. We have four tie rods, all of them were completely inspected all the way from the baffle plate to the top of the tie rod, this most recent outage, as a result of the hatch experience.

We also did ultrasonic testing on the design reliant vertical and horizontal welds, although the tie rods bypassed most of the welds in the load path, the design-reliant welds still remained the verticals that hold the shell sections together, and about 18 inches on either side of that intersection with verticals in the horizontals, and that's to keep the shroud from peeling.

So, we did ultrasonic testing on those design-reliant welds this outage, and we found no rejectable indications. So, our shroud really is in very good shape.

CHAIRMAN BONACA: Is what?

MR. LUKENS: It is in really very good shape.

CHAIRMAN BONACA: Okay.

MEMBER SHACK: How about your top guide, any cracking up there?

MR. LUKENS: We found no cracking in the top guide.

MEMBER SHACK: Never?

MR. LUKENS: Not ever, very low fluence plant.

MEMBER SHACK: Right.

MR. LUKENS: It's a pretty low power --

MR. DREYFUSS: Yes, small core, large vessel.

MR. MANNAI: This is Dave Mannai, just as a point of reference, you know, we installed that shroud back in 1996, so it's been operational 11 years.

MR. RADEMACHER: Also, the chemistry is very good in the plant, it has been for many years.

So, that has made a big difference to the performance.

MEMBER BARTON: There are some other low power BWRs that do have some top guide cracking.

CHAIRMAN BONACA: I think it is close enough to noontime, I would propose we take a break now. I think you are right about half through your presentation, and we have scheduled time for the completion of the presentation in the afternoon.

So, if nobody else has any questions regarding this portion of the presentation, then we will take a break for lunch and come back at 1:00.

(Whereupon, at 11:53 a.m., a recess until 1:00 p.m., this same day.)

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

12:58 p.m.

CHAIRMAN BONACA: Okay, let's start the meeting now, hear the second part of the presentation by the licensee, the other topics.

MR. DREYFUSS: Thank you.

Again, John Dreyfuss, Director of Nuclear Safety Assurance for Vermont Yankee.

A couple of quick housekeeping items here. There were three questions that were raised during the morning session I wanted to provide some updates to.

If you would please convey to Dr. Shack that he is correct, the baseline core damage frequency for Vermont Yankee is 8×10^{-6} per year.

Dryer frequencies I spoke to earlier, where we saw some of the acoustic resonant phenomenon, were as predicted at 137 Hertz, that is confirmed. I think I said 144 Hertz, it is 141 Hertz, and then there was a smaller, lower resonance peak at 115, 115 Hertz.

For moisture carryover uncertainty, we've recently performed an engineering change to review the accuracy of that calculation, and with a 95 percent standard deviation confidence the uncertainty is 0.0267 percent.

Additionally, I said that the normal average moisture carryover at full power is .12 percent. That is correct. We do see variation of .11 to .14, averaging to .12 nominally.

Moving on to the presentation topics for the afternoon. We'll speak to both drywall and torus shell integrity and the burning hydroelectric station. I will move briskly through these. If you have any questions as we go, please ask.

And, the next slide here, as we talk about the containment, both the torus and drywall key points that I wanted to bring out here is, showing the bullet here, we'll talk about the refueling bellows area, this is the area of interest here.

Additionally, the sand cushion region, we'll have better graphics of this that we'll be able to speak to, as well as the torus shell, and torus thickness.

This shows the Vermont Yankee configuration, I'd like to talk a little bit about. Normally, this area here is dry, during refueling evolutions we have communication with the moisture separator pit and this area is flooded. We have a stainless steel welded bellows here that goes the circumference around the cavity.

Additionally, a couple of features that I wanted to point out here is, we are trying to keep this region here dry, and it shows up a little better on your slide, but this leads down to the sand cushion region. We normally will drain this through this drain here. If, in the event that we have a bellows leak, there are a couple of features I'd like to talk about.

First, there's a trough that again goes around the circumference underneath the structure here. Additionally, there's a 3-inch leakage collection line that here is a flow switch. We surveil this flow switch every refueling outage, and it will alarm, in the main control room, at a value of 10 gpm, and we do test that.

Additionally, you can see that this line has, essentially, a trap feature to it, so if there's a small amount of leakage the preferential path will go this way. If the leakage is larger, it will come this way. Ultimately, these two combine together, they lead to a funnel in one of our heat exchanger rooms. They go to reactor building sump, over to rad waste, visible leakage that we can see, as well as it's alarmed.

MEMBER BARTON: How do you know that line is clear, if there's no floating --

MR. UNDERKOFFLER: Sir, Ted Underkoffler, it's a stainless steel syringe pipe --

MEMBER BARTON: Right.

MR. UNDERKOFFLER: -- full length, and it's just the shell and the trough out there. I believe it's clear because we hope to use these as a tell-tale drain for another system which is our spent fuel pool gates, and we've had no problems with this since 1972.

CHAIRMAN BONACA: Do you experience leakage?

MR. DREYFUSS: We've had no leakage from either the fuel pool liner or the refueling bellows.

CHAIRMAN BONACA: You mentioned that the alarmed volume in the control room is 10 gpm?

MR. DREYFUSS: That's correct.

CHAIRMAN BONACA: So, it's quite large.

MR. DREYFUSS: That is true. Again, these do come to a funnel in our fuel pool heat exchanger room.

CHAIRMAN BONACA: Yes.

MR. DREYFUSS: That funnel is visible where the piping comes into it, and we observe that on operator rounds as well.

MR. RADEMACHER: On daily operating rounds.

MR. DREYFUSS: Correct. So again, the barriers are the bellows, the leakage collection trough, the leakage collection lines that can be visually confirmed, and the flow switch associated with the collection system.

This show in the event of a bellows leak what the flow path would be and the alarm that we would get.

Now, this is the area below there is the sand cushion region, we do have an air gap here. The insulation that was initially, or foam that was initially in place, was removed during construction, so we have a clear gap there.

The feature here is, any leakage that would come down through the sand cushion we have eight sand bed drains. These terminate sticking out of the concrete about 14 feet in the overhead in the torus room, directly beneath the vent headers.

MEMBER BARTON: How do you know they are clear?

MR. DREYFUSS: We do inspections of those. We've done three inspections of them since 1987. We did boroscopic inspection and verified that they are unobstructed.

MEMBER BARTON: Thank you.

MR. DREYFUSS: There is some gravel in here. We have a screen over the top of this, and again, we've sneaked in this way to take a look.

MEMBER BARTON: Okay, gotcha.

MR. DREYFUSS: Very good.

A couple of other things that I did want to talk about, is we had seen that there's actually a natural convective current that occurs from here, that goes up through the gap. We've seen --

MEMBER BARTON: Chimney effect.

MR. DREYFUSS: -- yes, chimney effect, based on the temperature.

MEMBER MAYNARD: Where does that come out at? I mean, would that be through that drain line?

MR. UNDERKOFFLER: No, sir, Ted Underkoffler, Entergy, throughout the bioshield wall, the concrete on the outside, there are several annulus' around all the different pieces of piping, and that's where the air would typically exit.

MEMBER ABDEL-KHALIK: So, how would you -- how did you see natural conduction?

MR. LUKENS: We saw dust during the boroscopic examination, this most -- just prior to this outage. We had the boroscope all the way up to the screen at the sand cushion area, and we could see dust flowing past the boroscope on the screen. And, we found that in at least six.

MR. UNDERKOFFLER: Six of the eight, that was observable.

MEMBER BARTON: And, you might not see that on all the boilers, because some of them still have that insulation in them, right?

MR. LUKENS: Yes, that's right.

MEMBER BARTON: So, you don't -- you would get the flow through there.

MR. DREYFUSS: Another feature I wanted to point out is on the interior of the dry well shell, with the concrete floor here, this is the moisture barrier. We'll be talking about that as well a little bit later here.

So, summary of the protective features is that we do have a design that minimizes the potential for undetected water intrusion into the sand cushion region. There are diverse redundant methods for identification of leakage.

We did formalize in our operator rounds, we've been checking it on operator tours, these sand bed rings, we've been checking that in the operator rounds. We formalized that as an adjunct to the license renewal inspection that we had, the regional inspection, to be more specific about having the operators specifically check off those drain lines to check them. And again, you'll see a picture of the torus room floor and we have very easily detected leakage in that area, should we have it.

And finally, corrosion potential is minimized. We don't have any potential for wet insulation or chloride formation that would accelerate in corrosion.

I want to give you a few pictures of the actual construction of the dry well here. A feature I wanted to point out is, we did do an awful lot of rebar here, because it's a very large project and a number of pours, and the pours were done in sections, so there is some cold joint work that's going on that will play into another topic we'll discuss later, but this is where the dry well shell is.

You can see here again a better shot of the bottom of the dry well shell, the blast covers here. You can see the torus structure. You can see the vent header and the downcomers as well, as we're lowering the torus into place.

This is the sand bed region down below

here, sand line drain or sand bed drain comes out right here.

This is about where you'd see these guys, the sand bed drain lines, come out right around here. You can see the different concrete pours that were done to erect the reactor building concrete around the actual dry well shell.

MEMBER ABDEL-KHALIK: How and when was that insulation removed?

MR. DREYFUSS: As they built up the layers with the concrete pours, they pulled the insulation out as they went, reapplied it on the next level, did their pour, did their outer pour, took out the insulation, and stepped it up as they went, is my understanding of it.

MR. LUKENS: Yes, insulation may not exactly convey what it was. It was just 2-inch plastic foam.

MR. DREYFUSS: Yes.

MR. LUKENS: And, it was there to install a 2-inch air gap and generate the gap. So, it generated the gap.

And so, once the concrete was set the foam was pulled and the gap was there.

MR. DREYFUSS: So key thing summary here

is, we have not had any bellows or liner leaks. We have done these boroscopic inspections. We did do one in 2007, it was observed by a member of the regional inspection team.

Additionally, there was an awful lot of discussion during the regional inspection about one event that we had in 1991, again, not a bellows or liner leak, it was a main steam line drain leak. The total was a 10-gallon leak, in total, 10 gallons, and we have fully investigated and analyzed that actual leakage event and determined it to not have any impact on the dry well shell.

MEMBER BARTON: Can you tell me how a main steam line drain leak got into this area?

MR. DREYFUSS: I can. Let's go to the slide here. This shows the RPB. Here's the main steam line coming out. Here's the main steam line drain, external to the reactor building concrete.

MEMBER BARTON: Right.

MR. DREYFUSS: This is a dry well ventilation line, primary containment atmospheric cooling for inertia. What happened is, we had a very small wisp of a packing leak right here. We identified that there was something going on, actually, through the operator rounds. They saw, through a shrinkage crack here, that there was some water, just a little bit of moisture on the wall, and a small amount of puddling. We kicked off a multi-disciplined inspection and went after this, and we identified that small packing leak here, right here on this valve, that dripped down onto this line, which had a unique configuration and was slanted towards the primary containment.

MEMBER BARTON: Okay.

MR. DREYFUSS: It ran down this line, and this actually shows the steam line drain. This shows the primary containment air line, you can maybe see a little bit of perspective of how it slopes down there.

MEMBER BARTON: Right.

MR. DREYFUSS: So, what ended up happening is, it came down this line and dripped this way, and looking at it in 2007 we believe that the most probably path for it to get out to this torus room area was to go through the cold joints from the concrete pours and work its way out, rather than maybe this way and then work its way out to the concrete, or maybe --

MEMBER BARTON: But, you didn't see it through the drain line, though.

MR. DREYFUSS: We didn't see it through

the drain line.

MEMBER BARTON: Okay.

MR. DREYFUSS: And, there was no water beneath that drain line area.

MEMBER BARTON: I see. I understand. Thank you.

MR. DREYFUSS: All right.

So again, 10-gallon leak, we don't believe it had any impact on the dry well.

MEMBER ABDEL-KHALIK: What does the word acceptable in the second bullet mean?

MR. DREYFUSS: That is clear of any gross obstructions. We did see some small pebbles in the line, but, ultimately, the function of those drain lines is satisfied. We will be able to detect leakage, and we have a clear flow path through the drain line.

So, we can talk about the external surfaces of the dry well, switching over to the internal surfaces in 1999. First of all, we've always inspected the dry well interior. In 1999, we implemented the containment, ASME containment in-service inspection program, the IWE section, to do a dry well inspection in 2001.

During that 1999 inspection, we did

identify that that seal, if you can go to that seal picture, do you have that one -- yes, this moisture barrier here --

MEMBER ABDEL-KHALIK: Okay.

MR. DREYFUSS: -- during that initial IWE inspection we identified that that was a little bit degraded and needed replacement.

So, we planned the modification, go back to the slide, please, we planned a modification in 2001, we took out that barrier, and replaced the barrier.

We did do, at the time when we cleaned that up, we did do UT inspections of the dry well shell right at that floor junction, and that is, of course, where that sand bed region is, where the moisture would be, and we found nominal wall thickness there. We didn't see any corrosion, or general corrosion of any concern.

We also enhanced the moisture barrier design and reapplied that. We can into any detail you like on that, the new design, but, ultimately, the picture is here that I'd like to leave you with, because we have been watching and monitoring this containment over the course of the years, it is in good health. When we identify any issues, we correct them promptly, and that is what has allowed us to maintain the good containment health that we do have.

Moving on into -- yes, sir?

CHAIRMAN BONACA: Just -- your inspection was in that region right above the moisture barrier.

MR. DREYFUSS: Yes, sir, we excavated a little bit here, in order to clear this moisture barrier out. It varied a little bit, maybe up to an 1-1/2 inches in some areas, a little bit less than that in others, maybe a little more than that in a couple of areas. It's sort of hard to tell now that the seal is in place exactly how deep it went, but we did take the UT measurements right here along that interface region, matching up with that external region.

CHAIRMAN BONACA: And, you have no access whatsoever from the outside in the sand cushion region, there's no access.

MR. UNDERKOFFLER: That is correct.

MR. LUKENS: Just boroscopic.

MR. LUKENS: Right.

CHAIRMAN BONACA: Yes, no, I understand boroscopic, but I'm saying, some other designs we've seen there is a way to access the sand cushion region.

MEMBER BARTON: That's because we cored in through the concrete.

CHAIRMAN BONACA: Yes.

MEMBER BARTON: Because we had that problem with the liner.

CHAIRMAN BONACA: Right.

MEMBER BARTON: Otherwise you wouldn't have that access.

CHAIRMAN BONACA: Right. Okay.

MR. DREYFUSS: The internal look was good.

MEMBER ABDEL-KHALIK: What do you mean by an enhanced moisture barrier design?

MR. UNDERKOFFLER: Sir, Ted Underkoffler, Entergy, the original barrier was just in the last order, we have placed in a grout with a membrane, an epoxy seal, and then in the last I've been talking about we've -- in 2001 I personally examined that barrier for every refueling outage, as well as the region inspected with us this last outage, and we found that the flexible membrane is still flexible and pliable. So, we are ensuring that there's no moisture intrusion getting down there. There's no separation between the steel and the epoxy that was placed in there.

MEMBER MAYNARD: What was the condition of the seal that you replaced? Was it --

MR. UNDERKOFFLER: It varies depending on who you talk to. It was there in a lot of areas, it was --

(Whereupon, power outage, no loss.)

MR. UNDERKOFFLER: You are back up? Okay.

If I can continue, this is Ted Underkoffler, Entergy, that seal was in an amount of disarray depending on who you spoke with. It was not adhering in some areas, there was some slight general corrosion behind it. That was all removed, excavated, cleaned, the metal was cleaned for six inches above the joint, and represerved with the qualified coating before we put the grout and the moisture barrier back in place.

MEMBER BARTON: And, you don't have any access underneath that embedded area, what assurance do you have that moisture did not get down in that area?

MR. UNDERKOFFLER: They cleaned out to the point where we still had good concrete to metal on the base, where it was close adhering at that point, and that was one of the criteria, how far they had to go down and clean, til they were assured that that concrete and steel were still adhering, and before they replaced it.

MR. DREYFUSS: I also inspected the seal with our senior resident.

(Whereupon, loud feedback, nothing lost.)

MEMBER MAYNARD: Are you still up over there?

THE REPORTER: Yes.

MR. SULLIVAN: Did you get that, though?

THE REPORTER: I got it.

MEMBER MAYNARD: How is that spelled?

MR. ARMIJO: Before you leave that --

MR. DREYFUSS: Yes.

MR. ARMIJO: -- did you ever find water on the floor --

MR. DREYFUSS: No, of the torus room?

MR. ARMIJO: Other utilities have had that problem from different areas.

MR. DREYFUSS: No, we have not seen water on the torus room floor coming from other sources.

MR. ARMIJO: Okay.

MR. DREYFUSS: All right, next slide, torus shell integrity and monitoring.

MR. ARMIJO: How about the containment floor inside? Do you have a history of recirc pump seal leaks?

MR. UNDERKOFFLER: John, can I take that?

MR. DREYFUSS: Sure, Ted.

MR. UNDERKOFFLER: The -- Ted Underkoffler, Entergy -- we have had some standing water on the floor when we've had leakage. The last outage we -- our floor drains had like .029 gallon per minute leakage rate. The floors were dry when we went in this outage, absolutely nothing, they were dry and dusty.

So, any standing water, standing water is not typical, we may get it during a refueling outage, but then it's cleaned before we restart the plant.

MEMBER BARTON: It's worse where it's sloped, too.

MR. UNDERKOFFLER: Yes, I heard -- excuse me --

MEMBER BARTON: There's a slope to it.

MR. UNDERKOFFLER: Yes, we have four floor drains that go into the four drain sump. They are sloped and it goes away when it's there.

MR. DREYFUSS: This is the actual torus room here and the floor. I wanted to point this out because we do rely upon our operator rounds for shift daily rounds, to do inspections in this area. You can get full 360 access in this area, and it's always this clean and this neat. This is what it looks like.

These are pictures, actually, photographs from our most recent refuel outage. So, if there is any leakage, the operators are able to promptly identify that, which is why we are able to identify that 1991 event, and any other leakage that we do have.

MEMBER MAYNARD: What's the level compared to water level, is the water table below your plant level?

MR. RADEMACHER: Connecticut River water level is 242 and bottom basement floor is --

MR. UNDERKOFFLER: 213.

MR. RADEMACHER: -213.

MR. DREYFUSS: This shows the interior of the torus. This was during our 1998 initiative here to do some recoating. This is the before picture. You can see the water line here, but, ultimately, when we went in we found that the condition was in good shape. We also took the opportunity, though, to do some additional work, reapply the coating, make sure that it was going to stay in good health. This shows some of the after pictures.

MEMBER BARTON: In your inspections of the torus coating in refuel outages, do you have any experience with bubbling of that coating?

MR. UNDERKOFFLER: Can I take that?

MR. DREYFUSS: You are the IWE expert, go ahead.

MR. UNDERKOFFLER: I personally walked the ring header several times, our water clarity is to a point that we've been able to see to the bottom of the pool most outages.

We have seen -- we have not seen any blistering, we have seen some staining coming through in two areas, which we have gone out and done examinations of that with UT examination to see if there was any wall loss, and there was none.

So, we do not see bubbling as a general rule.

MEMBER BARTON: This is just from the platform from the walkway looking down, have you ever put divers in there to really go --

MR. UNDERKOFFLER: At the present time, we are scheduling 2008 to dive the torus to do the VT-3 examination of the wedded surfaces, and that will be ten years from the time that we did the recoating.

MEMBER BARTON: Okay.

MR. DREYFUSS: Okay, so this was the as left after the torus coating.

I wanted to talk a little bit, and this was an area where we had a lot of questions during the regional inspection as well, regarding the torus shell thickness and torus integrity.

First of all, the design pressure for the torus is 56 psig. The design basis accident loads that the torus will see is 27 pounds internal, so there's substantial margin between the design and the local loads that we see in the torus.

When we procured the plates, the specification was with the numbers that you see there, slightly bigger thickness at the bottom half, and that is to account for the height of water in the torus as well.

And, what a lot of the conversation revolved around was that, per the design drawings, there's a statement that says no excess metal thickness provided, in particular, at the bottom of the torus, the bottom center.

There's a lot of different ways to provide margin. It was not provided through procurement of very thick plates, beyond nominal. Again, we see the margin in the design accident pressures.

But, this prompted a lot of discussion. Let's go to the next slide and we'll talk a little bit. First of all, from a coating standpoint, this is one of our key barriers to prevention of corrosion and maintaining the margins that we have, is that torus has always been coated, the interior surfaces, we've got a zinc primer with this phenolic paint top coat.

We did reapply the top coat during that period of time when we did all of the Mark I containment MODs and put that new top coat on there.

In 1998, we did do a recoating of the torus again. We took it down to the bare metal, and put a qualified coating back in place there.

MEMBER BARTON: Same coating?

MR. DREYFUSS: Similar coating.

MEMBER BARTON: Okay.

MR. DREYFUSS: Again, a zinc and phenolic top coat. It met the original design.

MEMBER BARTON: All right, gotcha.

MR. DREYFUSS: All right.

So, it's always been coated. We've maintained the health of it, of the coating over the course of the years, and that's what has preserved the margin for us.

Going on, next slide, prior to our formal implementation of the IWE we did do additional IWE inspections at the period of time that we were doing the torus coating. We applied the IWE standards at that point in time. We found the condition to be satisfactory. We did find some areas of localized corrosion, we'll talk about that a little bit. That kicked us off into extensive UT measurements. You see 2,800 measurements in a couple of the bays here that were the worst-case bays that we had. We did establish UT examination of 15 areas where we did see some of this localized pitting.

Additionally, we have established an ongoing surveillance program at permanent locations where we take 286 measurements on an ongoing basis for trending and tracking.

MEMBER BARTON: Ongoing means what, during refueling outages?

MR. DREYFUSS: Yes.

MEMBER ABDEL-KHALIK: What was the reason for that localized corrosion?

MR. DREYFUSS: Jim?

MR. FITZPATRICK: It was areas of -- Jim Fitzpatrick -- it was areas of rust and coating degradation identified in the pre-service IWE exams. A lot of it was up near the water line, it could have been damaged coating during the -- in the Mark I MODs, we just identified the conditions and inspected the wall, they just didn't show, we still had wall.

MEMBER ABDEL-KHALIK: So, primarily, just coating degradation.

MR. FITZPATRICK: Probably.

MR. METELL: This is Mike Metell. I would say it would be any coating, you always have that potential for holidays, and it's always the threat of coatings, and that's why you inspect those to see where they might be.

The important piece here is that they were low in number.

MR. DREYFUSS: Okay. Relative to --

MR. JUNGE: We're going to tie back into the phone bridge. One second. Okay.

MR. DREYFUSS: So, to continue, as far as margins go, we have significant margins for both the design pressure accident loads and the Mark I DBA loads.

Additionally, we were -- and that's for localized thinning -- as far as generalized corrosion goes we do have substantial margin again for the Mark I deviated loads.

We remain, as we were, with limited margin for general corrosion at the bottom of the torus. We are not unique in this respect, this is typical of the Mark I containments, but something that we looked at during the regional inspection.

Additionally, the staff did challenge us on, how do you know what your corrosion rate is? And, let's go to the next slide.

MEMBER ABDEL-KHALIK: What is that limited margin?

MR. DREYFUSS: Jim, do you want to speak to the margin?

MR. FITZPATRICK: We averaged the measurements across the bay, 2 to 3 percent in places, that's about the lowest, 2-1/2 -- 2 to 3 percent over just taking static, what's ever required for the design pressure, and what is there now.

MEMBER ABDEL-KHALIK: And, what is the uncertainty in the measurement itself?

MR. FITZPATRICK: It's less than that, we are not -- taking the measurement, .04 over .586, so it's less than a percent, .04.

There's more fuzz in the UT, the uncertainty in the UT, we are taking repeat measurements from time to time. We are still seeing no changes greater than the uncertainty in the UT measurements. We have measurements nine years apart, and, basically, the next slide will -- these will show it here, but we are not seeing any real difference.

MEMBER ABDEL-KHALIK: Is the margin

comparable to the uncertainty?

MR. FITZPATRICK: At that one point, it's actually larger, it's 2-1/2 percent of the wall thickness is the margin, the last time we calculated it. I just got the data down this week, 2-1/2 percent was the minimum number for any one of the bays, and the UT is .01 -- .04 inch taller and some .586, whatever that number comes out. So, we are right in there. We are tracking changes now. We took a baseline set of measurements in 1998, and we took the same set of measurements, the same techniques, in 2007, and we didn't see any significant change, and we are going to keep monitoring it that way.

MR. UNDERKOFFLER: If I may add, the UT measurement process will not provide us a resolution, but we can discern what's happening here. It's that insignificant is the change in the readings.

MEMBER ABDEL-KHALIK: How can you tell that you still have margin?

MR. RADEMACHER: Well, we have significant margin to the LOCA loads. It's the corrosion aspects that we don't have. If you go back to the original comment that John made, the torus was designed for 56 pounds of pressure, and our accident pressure for the torus is 27, so there's a factor of two.

MEMBER ABDEL-KHALIK: We are talking about the corrosion margin.

MR. RADEMACHER: I understand. So, that's why we wanted to get into this slide to kind of give you the numbers from our UT measurements here in '98 and 2000, and maybe we could proceed on and then address your specific concern right after that.

MR. DREYFUSS: And, that was one of the challenges that we had from the staff, is how do you know what your corrosion rate is, if your margins are limited then it's really important to maintain good knowledge of what your corrosion rate is.

We used a qualified coating, our perspective on it was that we would not have generalize corrosion as a result of maintaining a good qualified coating.

However, we did perform additional UT measurements, and what we did learn was that from an average thickness standpoint, as well as the minimum thickness standpoint, we saw very, very small changes in the measurements. And, we calculate a general corrosion rate of on the order of 10^{-4} for, essentially, a very, very small corrosion rate, insignificantly small corrosion rate.

However, we will be continuing to monitor, because we recognize that this is a critical parameter for us to continue to monitor, manage the aging of.

MR. ARMIJO: I guess I'm a little confused. What was the as-built thickness at these locations, so we know where you started from.

MR. FITZPATRICK: The first UT measurements we took at these locations was 1998.

MR. ARMIJO: But, I mean, let's say --

MR. DREYFUSS: The specification number, Jim, was?

MR. FITZPATRICK: .584, .585.

MR. ARMIJO: You lost very little wall thickness to begin with, and you are saying -- so you almost had probably less than 10 percent margin to begin with as-built.

MR. FITZPATRICK: At the bottom, there's more margin as you go up.

MR. ARMIJO: At the bottom, right. Right.

MR. FITZPATRICK: And, from data we took in '98, the test strips, you can see the variation in the rolls of the plates, where they were welded, and there is a variance, but it's gradual along the plate.

MEMBER MAYNARD: I'm a little confused on the margin here. You have the LOCA pressures are so much lower than what the design pressure for it is.

I'm not sure why the corrosion margin is so small.

MR. FITZPATRICK: Corrosion margins for the 56 psi design pressure, that number came from entire dry well flooded.

MR. DREYFUSS: I should have specified that. 56 psig design limit is for a beyond design accident containment full flooding, where you were flooding the torus, venting the torus, flooding the dry well. So again, beyond any kind of design basis scenario.

When we look at the minimum required thickness for the Mark I deviated loads, that minimum thickness is .39 --

MR. FITZPATRICK: .392 for the general.

MR. DREYFUSS: -- so it's .392, we have substantial margin to that, and that's what we talked about -- I'm sorry, significant margin to that.

MEMBER MAYNARD: So, for Vermont Yankee's design basis accidents, you have considerable margin.

MR. DREYFUSS: Correct.

MEMBER MAYNARD: It's only if you want to maintain the original design margin that you have the very limited.

MR. FITZPATRICK: Yes, that is correct.

CHAIRMAN BONACA: The dry well is in your

EPG, right?

MR. DREYFUSS: Correct.

CHAIRMAN BONACA: So, I mean, it's still beyond design basis, but --

MR. DREYFUSS: It is beyond design basis, however, we do have procedural controls.

CHAIRMAN BONACA: Procedural controls if it would flood.

MR. DREYFUSS: That's why we want to maintain that, correct.

CHAIRMAN BONACA: Okay.

MR. DREYFUSS: All right, any other questions on this?

Okay, moving on. In conclusion, we do fully satisfy our design requirements. We are not seeing generalized corrosion, in particular, since we are looking at it since this 1998 recoating, we have not lost margin due to corrosion, and we will continue to monitor this to assure appropriate material condition. And, we will be doing UTs for the next three refueling outages at a minimum, and ongoing, I'm sure, beyond that.

I'll talk a little bit about the Vernon Hydroelectric Station. I did want to point out, here's a good shot of the cooling towers in service.

This here is the Vernon Hydroelectric Station. It's a relatively unique configuration. It's within a half a mile of the plant. The cabling goes, actually, underground from the station to the plant. There's a switch gear out here that is powered up. This line is continuously energized, and the Vernon Station does provide our station blackout source.

MEMBER BARTON: Does that picture show where your spent fuel storage area is?

MR. DREYFUSS: It doesn't exactly. It's on the other side of the reactor building.

MEMBER BARTON: On the other side of the reactor building there?

MR. DREYFUSS: Yes.

MEMBER BARTON: Okay.

MR. DREYFUSS: So, the Vernon Hydro was built in 1907. 2007, currently, it's undergoing some major upgrades by its current owner, Trans-Canada. I'll talk a little bit about that.

Here's the Vernon Hydro. It's our station blackout source. It's got two units that provide that blackout capability, 100 percent redundant cabling, as well as this line here is continuously energized and monitored in the control room. We can see that there's voltage on the Vernon tie.

When needed, this breaker here can be closed by the operators to power up buses here that would provide station loads to enable us to safely operate the plant and provide cooling for the plant.

The bottom line here is that the power wheeling from the hydro station to Vermont Yankee is all controlled by the New England Independent System Operator Rules, as well as the operating entities in that area. It's either contractually obligated or obligated by law. They are a blackout source, and that power does get wheeled on a prioritized basis to the plant.

And, over the course of the years here, since the 19 -- early 1990s, all of these components have undergone significant upgrades, as well as the cabling has been replaced.

Where we are at right now is, the hydro unit is getting a major capital investment. There's lots of money being spent to refurbish that unit. It's being upgraded from a 22 to a 30 megawatt station. It does provide us with the power of, essentially, one diesel generator in the event of a station blackout.

MEMBER BARTON: So, while it's going through upgrades, what's your reliable station blackout power source?

MR. DREYFUSS: They are maintaining the operability of this line right here, and the station blackout units are not being -- are not being impacted by the upgrades they are doing. They've got four -- a total of ten hydro units, four of them are not in service at the present time. Those are the ones that they are upgrading, and changing out water wheels, and putting new copper, as well as cabling in.

MEMBER BARTON: Since this is a different company now, what kind of contractual or written agreement do you have with respect to coordinating the operation, and when they do maintenance or whatever, do you guys know it? I mean, how does that all fit together with your two different companies that can do their own kind of thing at different times? How do you control what's going on at that end of the business?

MR. DREYFUSS: We have quarterly interface meetings that we participate in with the local grid operators, as well as the local generators, and we meet on a quarterly basis. We discuss and demonstrate on an annual basis, the ISO is required to demonstrate the performance of and capability of this Vernon tie line. So, that's done annually.

Every cycle, we also do a test of the Vernon tie unit. As far as the structural aging management of it, we are taking credit for the FERC inspections that are performed at the dam, and that is no precedent setting that we are doing here, the FERC inspections have been credited elsewhere, and that's where we are relying on those FERC inspections. We are confirming and working with the staff on how we will be confirming that those inspections are taking place.

MEMBER BARTON: Any work that's done by this Hydro station, is it -- and I'm talking about, you do your quarterly plannings or whatever, they have a problem tomorrow, they've got to do maintenance or something, is it coordinated through your control room?

MR. DREYFUSS: Yes.

MEMBER BARTON: How does that work?

MR. RADEMACHER: Trans-Canada, their local operator at Bellows Falls calls our control room and says what they are doing with the Hydro Station.

MR. DREYFUSS: We talk to them every day. We do have contractual agreements regarding -- they also control the flow of water, cooling water, down the river, so we talk with them every day about river flows.

In the event that this line is de-energized, it's alarmed in the control room.

MEMBER BARTON: Okay.

MR. DREYFUSS: So, we will learn, you know, if that line is out of service, we'll know about it.

MEMBER BARTON: Do you have any actions that you take at that point? Do you have any tech specs on this?

MR. RADEMACHER: There is no tech spec, however, we do have a TRM for a 15-day LCO we would enter into, limited condition for operation.

MEMBER BARTON: Okay, thank you.

MEMBER ABDEL-KHALIK: Historically, has this plant been out of service for an extended period of time, due to drought, or equipment failure?

MR. DREYFUSS: No, this plant has a very high reliability and it exceeds 99 percent, and we do -- we have just recently just touched base with them, and we calculated that, and it exceeds 99 percent reliability.

MEMBER ABDEL-KHALIK: And, the 15-day period in tech specs, how is that specified?

MR. DREYFUSS: Let me clarify that. It's

not a tech spec, we do have commitments that we have made to the NRC, and we have administrative controls established in our procedures that within 15 days we will restore the Vernon tie to service. We will also generate core shutdown, and we will generate a report to the NRC identifying that we have lost the Vernon tie, and inform them that way of the status of it.

MEMBER BARTON: And, that would require you to shut down the plant at that point?

MR. DREYFUSS: Yes, it would.

MEMBER BARTON: All right.

MEMBER MAYNARD: Can you also get from Vernon town-- you've got the feed from Vernon town on that.

MR. DREYFUSS: Yes. Yes, we can, and -- go ahead.

MR. JOHNSON: We really can't get a supply for the station blackout from the Vernon town, but there are four additional 69 kv transmission lines that feed the Hydro Station switchyard, and we can get a feed from them.

MEMBER MAYNARD: Okay.

MR. DREYFUSS: And, that was Paul Johnson.

MEMBER MAYNARD: Only a feed to Vernon

town, it's not --

MR. DREYFUSS: Right. And, you know, we very much encourage the upgrades that are going on at that facility as well. It's been around since 1907, nice to see that at the centennial mark they are doing these major upgrades as well.

You know, to recap, we've got a 15-year long-range plan. I think we've shown that we are doing significant upgrades to the plant. We've done that over the last several years, but the plant has always been well maintained and well run.

We worked hard to have a clean application. We worked with the staff to end up with a safety evaluation report in draft that has no open items, and we do believe that this plant is a strong candidate for license renewal.

We'll take any other questions that you have right now.

MEMBER MAYNARD: I don't have any questions, a comment. I'll be interested to see what the staff has to say. I do get nervous on some things, a lot of terms were used here, excellent material condition, everything is outstanding, high-quality visuals, but those are things that I'd like to get somebody else's perspective on besides your own there.

MEMBER BARTON: But, it was a high-quality presentation, I'll say that.

MR. DREYFUSS: Thank you.

MR. ARMIJO: Before you leave, I have some questions on fatigue, and the influence of environment and fatigue usage factors, particularly, for uprated plants, much longer life.

Could you just briefly kind of summarize your plan to deal with that, to assure yourselves that the usage factors are going to be acceptable, and what you'll do in the event you find that you exceed those usage factors?

MR. RADEMACHER: Norm Rademacher, we'll be glad to address that. We have performed preliminary analysis, and Jim Fitzpatrick will give the details, but the bottom line is that our cumulative usage factor at the end of life is less than one, and I'll turn it over to Jim.

MR. ARMIJO: That's your goal.

MR. DREYFUSS: No, preliminary.

MR. RADEMACHER: We've done the preliminary.

MR. ARMIJO: Okay, good.

MR. FITZPATRICK: We are committed to the staff, the commitments stated are, evaluating environmental fatigue for 60 years. First pass, we've got a contract for the work out to have NUREG 6260 locations for the vessel evaluated for 60 years with the environmental fatigue factors on there.

We looked at the lower shell and the annulus plate and the core support plate, that's going to the vessel, feedwater nozzle, core spray nozzles, recirc inlet, recirc outlet, and we've done a Class 1 -- ASME Class 1 fatigue analysis of the feedwater, recirc and RHR piping in the core spray area, including the environmental factors.

The preliminary calcs, it's less than one, I didn't want to publish a number because no one has reviewed it internal yet.

But, we've taken our 40-year design cycles, projected them out to 60 years, and we used a design transient, not taken real data, because it is still more conservative.

MR. ARMIJO: Are there any areas that are of concern that you haven't looked at yet?

MR. FITZPATRICK: I believe not. We looked at places -- feedwater nozzles is usually the critical one on a boiler, because you are injecting everything through there -- HPCI and RPCI go through feedwater.

And, the outage mixing tee is included, so the RHR injects into the recirc loop.

So, we've got everything -- we've got industry people looking at or done the work for us that have done this before, and we are using their expertise on this.

MR. ARMIJO: Okay, thank you.

MR. COX: Let me add just a little bit to that. This is Alan Cox. Of course, with power uprate, they evaluated the transient, so they've got the right magnitude of the temperature changes, that sort of thing, and we are using, as Jim mentioned, we are using the design basis number cycles, and what I wanted to add was that in addition to that we've got a fatigue monitoring program, we are tracking cycles, the projections, whether they are high or low, we are going to monitor those cycles with that program, and the program has steps built into it to redo the calculations as the design basis number cycles are approached.

MR. ARMIJO: Okay, thanks. Thank you.

CHAIRMAN BONACA: I have a question just regarding if that non-Class 1 fatigue, a statement is made that you did a TLAA, and evaluated that the projection -- you did not project that any component would have, you know, projected cycle exceeding 7,000. And, the question I have is, what kind of margin do you have in the evaluation, are you counting the cycles? I don't think you are.

MR. DREYFUSS: Jim.

MR. FITZPATRICK: That's system cycles, time you start up, that's a P31 non-piping.

CHAIRMAN BONACA: Yes, no Class 1 piping.

MR. FITZPATRICK: Right, well that isn't a cycle, that's one time you start the plant and go down, 7,000 would be --

CHAIRMAN BONACA: Okay, so what you are saying is that for that particular -- so the margin is huge.

MR. FITZPATRICK: Yes.

CHAIRMAN BONACA: That's why you don't need to do that calculation. All right, I just wanted to have a feeling for that.

MR. COX: Our experience on other projects has been that the place where you get closest to that number is if you have a sampling system, where maybe you are sampling --

CHAIRMAN BONACA: Yes.

MR. COX: -- two or three times a week.

CHAIRMAN BONACA: That's right.

MR. COX: And, we don't have that situation, so it's more like the number at start up to shutdown.

CHAIRMAN BONACA: Okay, thank you.

MR. DREYFUSS: Is there specific information we can provide you on that?

CHAIRMAN BONACA: No, no, no, I just -- I wanted to have a feeling, because, I mean, if you are telling me that your margin is, you know, a factor of ten, then I'm worrying about the fact that they had 25, the projected cycle, is that close to 7,000. If it was close, then the question remains, you know, you should be counting them.

MR. DREYFUSS: Yes, sir.

CHAIRMAN BONACA: Any other questions?

MEMBER ABDEL-KHALIK: Yes. Which stability option do you have in the plant?

MR. RADEMACHER: Stability option delta.

MR. MANNAI: This is Dave Mannai, stability option 1 delta.

MEMBER ABDEL-KHALIK: 1 delta, 1D.

Now, in your steam line frequency analysis, have you detected any lower frequency escalations at all, below 35 Hertz?

MR. DREYFUSS: I am going to have to

consult with the experts on that, but as I recall those very low frequencies we did not see anything in that area, and there was a limit on the acoustic model that it would not be accurate down in that region.

MEMBER ABDEL-KHALIK: Right.

MR. DREYFUSS: We did not see anything from the CFD model that we performed.

MEMBER ABDEL-KHALIK: No, but I'm asking about the data, not the model.

MR. DREYFUSS: Nothing that I recall, but we'll specifically -- we'll get you an answer on that before the end of the day.

MEMBER ABDEL-KHALIK: Thank you.

CHAIRMAN BONACA: Any other questions from the members?

I'd like to thank you for the presentation. It was very clear.

Now we will have the staff come up and tell us about their review of the SER.

MR. KUO: While the staff is going to set up for the presentation, I would like to make a little bit of introduction. The presentation is going to be led by Jonathan Rowley, who is the Project Manager for the Safety Evaluation, and then we also will be joined by Mike Modes, the Inspection Team Leader from Region

1. And, to my extreme left is Rich Conte, who is the Branch Chief from Region 1, and we also have in the audience Marsha Gamboni, who is the Division Director from Region 1. In addition, we also have various staff members and audit team members sitting in the audience, in case that you have any questions, detailed questions, that they can answer.

So, Jonathan.

MR. RADEMACHER: Excuse me, Mr. Chairman. I have Scott Goodwin from Entergy to answer that question on the low frequency.

CHAIRMAN BONACA: Okay, please.

MR. GOODWIN: We didn't detect any low frequency emanations from the strain gauge measurements, and the susceptible areas of the dryer, principally, the front vertical hood, we stiffened up such that the natural frequencies in that area were about 70 Hertz, so there would be no match and amplification in that area.

CHAIRMAN BONACA: Thank you.

MR. KUO: In Jonathan's presentation, he's going to go over the details for audit, and Mike Modes is going to go over details of inspection. But, as a brief summary, we have done three full weeks audits. We have done three full weeks audits. One week for scoping and screening, and two weeks for aging management, and then we have done two days -- two two-days additional audit to resolve issues, so a total of four audits, two weeks -- four weeks, two times partial audit for the safety review.

And, the region has done two four weeks inspection. So, it is very extensive audit and inspection combination, and they will go through the details of it.

MEMBER BARTON: It's just not the number of audits or inspections you do, it's the quality of them.

MR. KUO: They will give you the details of the quality of the audit.

MR. ROWLEY: Good afternoon, everyone. Before I get started, I know P.T. introduced Marsha Gamboni, but she just had to leave for a meeting, what kind of a meeting was that, Mike?

MR. MODES: She extends her apologies, but she had only stopped by to observe, she's on her way to a FEMA meeting.

MEMBER BARTON: So, was she part of your presentation that we are going to miss or what?

MR. MODES: No, she just wanted to extend her apologies. Having been introduced, she then immediately gets up. She didn't want to appear impolite to you, gentlemen. She wanted me to let you know that she had a FEMA meeting to go to.

MEMBER BARTON: Oh, gotcha.

MR. CONTE: I'm responsible, since I work for her. I work for her, so I'm responsible now.

MEMBER BARTON: You got the bag, Rich, all right. All right.

MR. ROWLEY: Good afternoon, my name is Jonathan Rowley. I, along with a contingent of NRC staff, will discuss the staff's review of the Vermont Yankee license renewal application as documented in the Safety Evaluation Report, confirmatory items related to the license renewal of Vermont Yankee Nuclear Power Station.

I will begin with a brief overview of the review. I will then turn the microphone over to Mr. Michael Modes to lead the discussion on license renewal inspections. At the conclusion of that, I will discuss Sections 2 through 4 of the SER.

The license renewal application submitted by letter of June 25, 2006, they discussed small point containment, 1912 megawatts thermal, 650, megawatts electric, and the license expires on March 21, 2012. The plant is located in Vernon, Vermont, which is about five miles south of -- north of Brattleboro, Vermont.

The Safety Evaluation Report was issued on March 30,2007. They have a zero open item system for inventory, and staff provided input into the SER with the aid of 386 audit questions and 85 RAIs.

And, obviously, the audit team has conducted various audits and activities at Vermont Yankee during the periods as seen here on the slide, and P.T. mentioned there was three weeks, as you see on this slide.

And then, there were two partial weeks, and in addition there was regional inspection activities, and there were public meetings held to discuss the status of our audits, as well as the regional inspection, and those dates are on the slide as well.

MR. CONTE: Just a minor clarification. There was an additional inspection mid May, and that’s evident in our presentation shortly.

MR. ROWLEY: At this time, I’d like to turn the microphone over to Mr. Mike Modes, and allow him to take us through the license renewal inspection.

MR. MODES: Gentlemen, it’s always a pleasure to be here.

We have performed a two-week, on-site inspection using one entire inspector week to take a look at the then CFR 54.2(a) portions, non-safety/ affects safety, utilizing 19 aging management programs we used 12 inspector weeks for the remainder.

Because we couldn't discern from the records or from our interviews a complete understanding of the inside sill seal and the condition of the inside of the dry well, we deemed it necessary to defer the exit and defer the report until the outage when we could get an inspector in there.

VY was extremely accommodating. I think the second person in the containment, as the outage began, was, in fact, one of our inspectors.

That was a confirmatory inspection for the internal base sill, which you've talked about earlier, a confirmatory inspection of the dry well condition, and we were very anxious to take a look at the follow up on torus ultrasonic testing, and that is the reason that this report came to you so late. We were constrained by both your meeting and the beginning of the outage.

As usual, the perfunctory PI chart, rather than bore you with all the greens, I thought I'd just highlight the one white. Don't ask me any questions, this is H.P., but the H.P. inspectors said that the white was a consequence of an advanced pressure shearer being shipped from VY to Susquehanna in August, which exceeded the contact radiation limit of 200 micro curies by 620. So, it was contact of 820.

He has taken a look at the corrective actions. They seem to be good, but he is not planning to follow up using our IP95001 until 7/9.

CHAIRMAN BONACA: You are going to tell us about your inspection of the dry well, right?

MR. MODES: Yes, in the next slide.

CHAIRMAN BONACA: There it is. Okay.

MR. MODES: So --

CHAIRMAN BONACA: You mentioned it before, and I thought --

MR. MODES: -- like I said, I thought I'd get a green slide out of the way.

CHAIRMAN BONACA: That's great, okay.

MR. MODES: Okay. Our inspection noted a number of weaknesses. One was in the Scoping and the Turbine Building. The applicant didn't completely embrace the idea of some of the non-safety/affects safety. And, we had the benefit of having reviewed in a similar approach at Pilgrim, so Pilgrim VY fits, and so we are following through on these issues as they come up.

They were very agreeable. They agreed with us that if it applied at one plant of similar design it ought to apply here, and it was corrected.

The containment management, let's talk about that. There were a number of weaknesses that we identified in the incontainment management program. For example, visual examination acceptance standards, there were none. They did examinations without a procedural check list that would identify -- for example, the inspector took a look at the boroscope that they referred to, and asked those individuals doing the boroscope, who were highly qualified VP level threes, whom I've known on ASME committees for very long periods of time, exactly what is the acceptance standard, what about that indication, what would you do if you saw this, and they, basically, had no proceduralized checklist or acceptance standards.

They had no procedures in place for sand bed drain monitoring. It was not a regular situation, they didn't have tubing going down the catch basins, et cetera.

MEMBER BARTON: They did have -- they did have an observation program by operators' rounds, right?

MR. MODES: I believe so, but again,

it was not a comprehensive program of monitoring for the drain. In other words, we expected -- we expected in an aging management program to see substantially more than we did when we got there. Those weaknesses were identified and corrected, and they do now have a strong program in that area.

MEMBER ABDEL-KHALIK: So, when the operators do their rounds, they don't have a checklist with them?

MR. MODES: They didn't until we showed up. The boroscope was being examined by, if you will, the VT level threes, evidently qualified individual who knows what he's looking for, they were depending on that individual reporting anything that was untoward. For example, the large pebble that was a blockage, that certainly got into the system, it certainly was reported, they certainly were doing an adequate job, it was just not proceduralized. They didn't have acceptance standards. They didn't -- they didn't go in thinking, here's what we'll be looking for, let's test our assumptions, that kind of stuff.

And, as Mr. Dreyfuss pointed out, we were somewhat skeptical about the torus corrosion rate as well, because it was a single point corrosion rate. They had done it in '98, and, basically, the coating being in good condition, they depended on that visual examination, and that combination to come about with a zero corrosion rate. And, as Dreyfuss pointed out, there were a lot of questions. We spent a lot of time on that subject, trying to understand how they got from '98 to here.

And, as you can see, they have once again completely remedied the situation. They have a valid test, they've taken into account the corrosion rate. They have a calculated two-point, and they've committed to go forward accumulating more points so that they can strengthen their position.

In addition, other weaknesses were noted throughout. You probably noticed in our report a lot of references to corrective actions that are being taken on their part. One of the other examples was the fire water system, they lacked a corrosion monitoring and biofouling management program. These are just illustrative of the many points in the report where you refer to a corrective action, where weaknesses were noted and were corrected.

So, what we did is a three-part exam. We did the two weeks on site, and then we deferred until the outage, we did a week, and we finally came away with the inspection team concluded, as we did in the report, that the screening and scoping of non-safety related system structures and components was implemented as required, et cetera.

Any questions?

MEMBER MAYNARD: I'm trying to get a feel for, it sounds like many of the things you are talking about were not documented well, or criteria wasn't established. In practice, they were doing a number of these things, but it sounds like some of these things might have been a combination, been both, it wasn't part of the program and they weren't doing them.

MR. MODES: Right. I think what you are getting at is, let me try to characterize this, I would not -- if I went through the inspection and they hadn't taken the corrective actions I don't think I would have strongly questioned their program's ability to do the job. It just lacked the kind of definition that we would require for such a long extended period.

Does that help?

MEMBER MAYNARD: Yes, that was the question.

MR. MODES: I'll turn it back to Mr. Rowley.

MR. ROWLEY: Yes, thanks, Mike.

I'd like to begin the discussion of the

SER, the results we found in Section 2.

MEMBER MAYNARD: I'm sorry, I do need to go back. I do want to ask my question. Your perception overall, the material condition of the plant, with the inspection being in there and stuff.

MR. MODES: I would not paint it as glowing as they do, because, obviously, I don't own it, but it was in pretty good condition.

MEMBER MAYNARD: Okay.

MEMBER BARTON: What do you mean?

MR. MODES: What do I mean, I don't own it?

MEMBER BARTON: No.

MR. MODES: I'm sorry.

MEMBER BARTON: What do you mean by pretty good versus --

MR. MODES: It was in --

MEMBER BARTON: Do you think they have a strong material condition program --

MR. MODES: Yes, they do. It is in good -- I was being a little bit --

MEMBER BARTON: Okay.

MR. MODES: -- I'm sorry, it is in pretty good condition.

MEMBER BARTON: Not rust glowing and all that stuff.

MR. MODES: No, no, no, no.

MEMBER BARTON: Leaks all over the place.

MR. MODES: No.

MEMBER BARTON: Okay.

MR. MODES: No.

MEMBER ABDEL-KHALIK: The pictures you --

MR. CONTE: The pictures reflect accurately the condition of that plant. I was in the torus room looking at the drain.

MEMBER BARTON: It looks like pretty good material condition.

MR. MODES: Yes. He went in.

MEMBER BARTON: It's got to be, he wouldn't go into a lousy place.

MR. MODES: I work for him, I wouldn't say that.

MEMBER MAYNARD: I've never seen a regulator say things were quite as good as the licensee.

MR. MODES: No, never will.

Okay, am I done?

MEMBER BARTON: Yes.

MR. MODES: All right, thank you very much.

MEMBER BARTON: But, don't go.

MR. MODES: No, I'm not going.

MR. ROWLEY: Okay, Section 2, step instructions and components subject to aging management review, 2.1, methodology, staff concluded that the methodology was consistent with the requirements of 10 CFR 54.4 and 21(a)(1).

Section 2, plant level scoping, there was no omissions found for system instructions and scoping for license renewal.

Section 2.3 is scoping and screening results of the mechanical systems. This is where the six confirmatory items are located. There was not enough information on the system drawings or the LRA for the staff to determine scoping boundaries for several systems.

Region 1 inspection team was asked to verify these boundaries during its on-site inspection, so we asked them to look at service water, augmented off gas, circulating water and reactor water clean-up, in terms of (a)(2), and for the components of the John Deere diesel for things related to (a)(3).

Here are a list of the confirmatory items, and they are -- I'm quite sure you've read them, they are in SER, in your Section 1.6.

The other three confirmatory items, and get to the confirmatory item stats.

CHAIRMAN BONACA: Just a second. We have to look at it.

MR. ROWLEY: Okay, sorry.

CHAIRMAN BONACA: Okay.

MR. ROWLEY: Of course, the status, the regional inspection team provided us enough information for us to close the concerns with the augmented off gas system, and the John Deere diesel system, but the issues remain for service water, circulating water and reactor clean-up system, reactor water clean-up systems, and those are under discussion as Entergy has mentioned earlier. We've had various calls over the past week. We have a path of resolution, it's just a matter of getting that documented and on the docket, and I think those four items will be closed shortly.

Section 2.4, there were no omissions of structures within the scope of license renewal, as well as Section 2.5, there were omissions of illegible instrumentation in control system components within the scope of license renewal.

In summary, Section 2, the applicant's scoping and screening methodology meets the requirements of -- CFR 54.4, and 54.21(a)(1), and the resolution of the confirmatory items the scoping and screening results for the system structures and components within the scope will be satisfied as well.

Section 3 discusses the aging management review results, 3.03 talks about all the aging management programs. As the applicant said, there were 39 AMPs, and here we have a slight delta. We'll work on getting that worked out.

In SER, we have ten new programs and 29 existing, whereas, they said there were nine new programs. So, we'll work with them to straighten that out and determine what that delta is.

There were three new AMPs added as a result of our review, bolting integrity, metal enclosed bus, and bolting -- bolting cable connections, and I will discuss those three as well as the Vernon Dam program over the next four slides.

Originally, the applicant had credited service water inspection and system walkdowns to manage aging of bolting. The staff strongly disagreed with that install AMP XI.M18 requires a more comprehensive integrity program, and as a result of our discussions with the applicant they have decided to add the bolting integrity program into their license renewal application, and that's one of the new programs stated earlier.

Also, with the metal enclosed bus inspection program, it's in scope of license renewal for the station blackout restoration path, GALL requires that they have a program. The applicant didn't, and now they do, as a result of our review.

The third new program added was the bolting cable connections, XI.E6, it's a new program that the applicant didn't have, and they have committed to implement this prior to the period of extended operation as well.

A program of interest was the structures monitoring Vernon Dam FERC inspection program. We had numerous discussions with the applicant over this, concerns arose over -- third party status in this. We know that with other applications the dam -- that required a dam as a station blackout, they had part ownership in it, so they could do some of the various FERC-related activities. In this case, VY wasn't doing those things, so that's where the discussion came in, and are firm with the aging management of the dam being done by FERC, as well as the dam owner, but we are in discussions with the applicant on how they can get them involved in this and show more accountability for them, since we are regulating them and no one else.

MEMBER BARTON: I've got a question on that.

MR. ROWLEY: Yes.

MEMBER BARTON: An AMP for the station blackout generators, I read somewhere that the applicant used redundancy as a reason for not requiring an AMP for that equipment.

MR. ROWLEY: They attempted to do that. That was in the early stages of this discussion, yes, that was one of the arguments, but --

MEMBER BARTON: That was not accepted?

MR. ROWLEY: -- that was not acceptable. We did not accept that argument.

MEMBER BARTON: Thank you.

MR. ROWLEY: And, they have decided to do the XI.E6 program to deal with the illegible parts.

MEMBER BARTON: Thank you.

MR. ROWLEY: Any other questions before we move on?

Section 4, where we have a discussion on time-limited aging analysis, Section 4.2 is the reactor vessel neutron embrittlement analysis, and there were six TLAs inspected by this, and I will talk about the reactor vessel fluence and the upper shelf energy.

Here's a chart of the quarter peak fluence extrapolations performed by G.E. using NRC-approved methodology. This incorporates the power uprate, and due to power uprate it's lower in the core, which is 75 inches above the bottom of the active level versus the 85, fluence below the active level in areas circulating in that nozzle is slightly higher for the 60-inch curve, and a 19 percent correction is added in here, as you can see on the chart, for uncertainties, and they are within boundaries for reactor vessel fluence.

Upper shelf energy, we see that VY falls in the acceptable range for relocations that are the most susceptible here, and they are projected to the period of extended operation.

CHAIRMAN BONACA: This is at 54 acceptable power --

MR. ROWLEY: I do believe. Lambrose? The question was, is this for 54?

MR. LOIS: Yes.

MR. ROWLEY: Verified 54 EFPY.

MR. LOIS: Lambrose Lois, Reactor Systems, the values that you saw previously --

CHAIRMAN BONACA: The question is, the value calculated here are 54 acceptable power --

MR. LOIS: This is the upper shelf energy, I'm only responsible for the fluence portion of that, and the values we saw previously were the same value across, it's a binding value, it's higher than they calculated for the 54 EFPY, that's true.

Now, whether the upper shelf energy is this value or not I do not know.

MR. KUO: Jim Medoff, Staff Audit Team Member, might be able to answer that question.

MR. MEDOFF: I am Jim Medoff. I'm with the Division of License Renewal, Section C Staff. The relevant rule is 10 CFR, Part 50, Appendix G, for upper shelf energies it requires that your end of life upper shelf energy, in this case it would be the 54 EFPY value be greater than 50 foot pounds.

So, for the plate they met that criteria. If you don't meet that criteria, what the rule requires you do is do an equivalent margins analysis to show that you still have equivalent margins of safety equivalent to those required by Appendix G to Section 11.

And, what we allowed is the VIP developed some upper shelf equivalent margins analysis criteria for the limiting plate, limiting weld materials, and as you can see from the table it's 23-1/2 percent drop allowed for a limiting plate, and a 39 percent allowable drop for a limiting weld. And, if you look at the table you can see that they met those criteria.

They didn't meet the 50 foot bounds, but they did meet the equivalent margins criteria.

MR. ROWLEY: Section 4.3 discusses the metal fatigue analysis. Vermont Yankee has committed to do one or more of the following to use prior to the extended period of operation, to assure that their cumulative usage factors is less than one, perform aging management necessary or repair/replace the affected locations.

And, Mr. Fitzpatrick, I think, talked about the six susceptible locations in his discussion earlier, as they relate to NUREG 6260.

The staff concludes that the metal fatigue analyses are in compliance with 10 CFR, 5421(c)(1) (i),(ii) and (iii).

MEMBER SHACK: I got here late, I guess, was there a discussion over when you are computing the FEN with the fatigue analysis that you use the oxygen level corresponding to hydrogen water chemistry? Is that accepted by the staff?

MR. KUO: Robert Hsu, the Audit Team Leader, he will answer the question.

MR. HSU: This is Robert Hsu. I'm the Audit Team Leader. As far as those FEN values, actually, right now putting the NUREG, the limitation is that 50 PVP, so 50 PVP, and then you have one way to calculate it, and the rest of that.

Now, currently, at the time we do the audit, several of the nine locations they are going to redo the analysis to satisfy things are less than 1.0. So, we are expecting, according to what they say, we are expecting at the time they redo the analysis, they will incorporate all those factor in there.

So, we think this is acceptable.

MEMBER SHACK: And, they will compute the FEN with the --

MR. HSU: Put that a consideration, because what we are asking is --

MEMBER SHACK: 100 PVP level, but I would expect in normal water chemistry?

MR. HSU: Yes, whatever -- because we cannot distinguish, okay, at the time they have normal water chemistry and hydrogen water chemistry, at the time they establish the hydrogen water chemistry we know that's less than 50 PVP, but at the time we asked that question, Entergy could not answer that question, what was the use. They say when they did the re-analysis they would incorporate all those correct value in there.

And, at the same time, seven of the nine components is greater than 1.0, we understand they are going to use one of the commitment to redo the analysis to satisfy this TLAA requirement.

MEMBER SHACK: Okay, but if they use the lower value, they would then have to commit to using hydrogen water chemistry, which most plants haven't done for license renewal, as I understand it.

MR. HSU: Yes, that's right, because at the time they are not quite sure what they used before, the normal, because the fatigue is the whole 60 years time period.

MEMBER SHACK: Right.

MR. HSU: So, we know what time period they used the hydrogen water chemistry, and prior to that time they need to figure out, okay, what kind of PVP they are using. So, we point out that.

MEMBER SHACK: But, if they use the lower factor going forward, that's going to mean they are going to have to commit to hydrogen water chemistry.

MR. HSU: Yes.

MEMBER BARTON: Can the applicant address this issue? I'm confused.

MR. FITZPATRICK: Yes, we can.

MEMBER BARTON: Thank you.

MR. FITZPATRICK: Jim Fitzpatrick. We have the preliminary calcs -- you weren't here for my answer -- we have taken into account on normal water chemistry operation, and then the hydrogen water chemistry, and the different power levels, and going through and calculating the same thing.

MEMBER BARTON: What do you do going forward?

MR. FITZPATRICK: Well, we will -- how we are operating now, we are projecting that going through.

MEMBER BARTON: Okay, so that's a commitment to use hydrogen water chemistry then.

MR. FITZPATRICK: Yes.

MEMBER BARTON: Thank you.

MR. ROWLEY: Any other questions on metal fatigue? Okay.

Overall, there were 47 commitments in the SER, and 27 in the original LRA, 15 as a result of our audit activities, and five as a result of regional inspection activity.

You might notice that there are maybe 49 in the SER, but two of them were deleted. Look at the numbers, there are 49, but if you look at the actual commitments there are 47.

MEMBER BARTON: Which ones were deleted?

MR. ROWLEY: There were two that were rolled into one. I can't --

MEMBER BARTON: That's 48, how do I get to 47?

MR. ROWLEY: -- give you the numbers, like 34 and 35 might have been rolled into 37. I'm not 100 percent sure.

MEMBER BARTON: I don't know what -- those are just numbers, I don't know what the issues were.

MR. ROWLEY: They all dealt with the Vernon Dam commitments.

MEMBER BARTON: Okay.

MR. ROWLEY: I can look in the SER real quick, if you'd like.

MEMBER BARTON: That's all right, I can find it if it's in there.

MR. ROWLEY: Yes.

MEMBER BARTON: Thank you.

MR. ROWLEY: The basis of our review, we think that the requirements of 10 CFR 5429 have been met by the applicant.

And, questions?

MEMBER BARTON: Yes, structures monitoring program, Vermont Yankee, their inspection program for crane rails, and girders, is not under the GALL AMP, they claim that they are going to control this through their surveillance of the preventative maintenance program. My question is, did the NRC review the surveillance and preventative maintenance programs and assure themselves that they would do the job?

MR. ROWLEY: Yes, Robert Hsu looked at the surveillance, and I would ask that he address that.

MR. HSU: Yes, okay, we did a review of the surveillance and the preventative maintenance program, and we find they did handle that consistent with GALL.

MEMBER BARTON: Okay.

CHAIRMAN BONACA: Any other questions from Members?

MEMBER ABDEL-KHALIK: I understand that the reactor vessel fluence numbers were done using approved methods. Do we have any idea about the uncertainties in those calculations?

MR. ROWLEY: Yes, Lambrose?

MR. LOIS: Again, this is Lambrose Lois, Reactor Systems. The uncertainties acquired by the methodology are plus or minus 20 percent one sigma. However, and that was established way back in the

'80s, at the time that we instituted 10 CFR --

MEMBER BARTON: I can't hear you, I hear an echo.

MR. LOIS: Okay, let me start again. The original requirement for accuracy, which was 30 years ago, was plus or minus 20 percent one sigma. However, as time went on, all of the vendors have improved the accuracy considerably.

So, the latest we have is something in the neighborhood of about 10 percent. However, that's not a legal requirement.

MEMBER ABDEL-KHALIK: Thank you.

MEMBER BARTON: I've got another one, Mario, I've got another question.

CHAIRMAN BONACA: The question I have is regarding this 47 commitments. So, the region, I guess, will be inspecting the plant before it goes to extended -- to the period of extended operation, to verify that these 47 commitments have been implemented?

MR. METELL: We are currently in the process of taking a look at IP, Inspection Procedure 71003, in order to better understand how the commitments play out, what level of inspection will be required.

So, although there is going to be a commitments inspection, I would not blanket statement it to say that we'll look at all 47.

CHAIRMAN BONACA: This is why I'm asking this question, is that many of these commitments are vague. They are a promise that something that has the elements intended by the regulation, or by GALL, or whatever else they are committed to, seeing they are being prevented.

There is always an evaluation of adequacy. If you review the implementation of something, you can conclude that, yes, it is adequate, no, it is not adequate.

I'm trying to understand to what extent the verification is going to be made, because, you know, we have discussed before the possible -- of inspections and commitments, and what the NRC can really deliver.

MR. KUO: Right, Dr. Bonaca, as Michael mentioned, that we are currently revising or taking another look at the IP-71003, and actually we are going to revise the inspection procedure as we -- when we are ready to do that.

Right now, we have met with our regional representatives and Headquarters inspection folks, and trying to come to an agreement as to what is really needed to ensure before they enter into the renewal period we can say that all these commitments are being satisfied.

CHAIRMAN BONACA: You may need again to assemble teams as you have done here for audits.

MR. KUO: Right. How to carry that out, the inspection, is the subject of discussion.

CHAIRMAN BONACA: Yes.

MR. KUO: How much resources is going to be needing, that’s another discussion.

So, we are looking at that, and as soon as we are about ready we will issue a draft IP 71003 revised, and then issue it for public comments, and eventually we will involve the industry actually to look at this, just, you know, to work with them to make sure that the inspection procedure is really practical and make sure that all the commitments will be able to be satisfied.

CHAIRMAN BONACA: Sure, and how the commitment is going to be maintained.

MR. KUO: Right.

CHAIRMAN BONACA: The reason I’m asking these questions is that as a reviewer, and, you know, I’m sure that my colleagues have the same impression, many of this review of some items end up with a promise.

MR. KUO: Yes.

CHAIRMAN BONACA: But, it’s an open promise that doesn’t say how the commitment is going to be implemented. It says that we will manage aging during the period of extended operation, and that means a lot of things, like TLAAs.

MR. KUO: Right.

CHAIRMAN BONACA: And, decide if you are going to manage aging during the period of extended operation is like saying thank you very much, how do you do that?

MR. KUO: And, especially, the one example that we just looked at, like a fatigue --

CHAIRMAN BONACA: Yes.

MR. KUO: -- the commitment is that easier to maintain, should have less than one, 1.0, or provide an aging management program, which one are you going to really take? I mean, that is like you say, it’s an empty commitment to me. It’s very uncertain in terms of interpretation.

So, we want to make sure, in this revised 71003, to really put some details there as to how we are going to do that.

CHAIRMAN BONACA: Okay.

MR. CONTE: There will be a -- based on my review of this draft procedure -- there will be an operating principle on which the team will maintain close contact with the License Renewal Division for questions related to technical adequacy, in terms of what was committed and what's acceptable, if there's any grey area.

CHAIRMAN BONACA: And, hopefully, also there will be some lessons learned and involvement with NEI, I mean, the work with NEI was essential to kick off the program, and good progress has been done. But, at some point it's important that the industry is involved in -- most of all in communicating experience here about aging and how issues are going to be dealt with.

MR. KUO: Right, that's definitely part of this effort. We want to work with industry, you know, get lessons learned, and whatever the thought they have, and try to make it practical.

MR. CONTE: Many of these commitments are a matter of public trust, and in some cases you just can't risk -- so there is a deterministic aspect of what we are planning on doing for these commitment inspections, again, based on my review of the draft that I've been working with License Renewal Division on.

MR. KUO: And, if you are interested later on, when we are ready we can come before the committee and give you a brief on it.

CHAIRMAN BONACA: Yes, that would be important.

The other issue that I would like to, you know, mention this morning, is the issue of exceptions to GALL and, you know, where are you going there? I mean, that's an action to be done.

MR. KUO: Sure.

CHAIRMAN BONACA: What I would like to do is, since we are close to the end of the meeting, rather than taking a break, I would like to go around the table and get a sense from the Members today of what they've seen, and get their impressions.

MEMBER BARTON: Can I say something before you do that?

CHAIRMAN BONACA: Please.

MEMBER BARTON: I'll never bring it up again.

CHAIRMAN BONACA: Okay.

MEMBER BARTON: But, I'm hung up on fuze holders, and I'll tell you why, when this first came out there was a lot of, what do you, da, da, da, da, da, and then some applicants came in, and if I remember correctly, committed to do some kind of program on managing fuze holders. I think I'm right on that, right? Am I?

MR. DREYFUSS: Yes, you are right.

MEMBER BARTON: Okay. Now, the last few applications I've been reviewing, people say no program need, it's part of an active device. Well, you know, guys, water and electrons they both flow, you've got pumps, and you've got water runs through a pump casing, through a loop for extra flow, you've got electrons running through electrical circuit, and they go through the fuze, and through the fuze holder, what the hell is the difference? Why isn't the fuze holder passive? Why isn't it included as part of a management program, you've got to look at fuze holders? Especially, you know, you are running 30-40 years, and you tell me you are not going to do anything about assuring yourselves that the fuze holders are not a problem?

CHAIRMAN BONACA: I'd like to hear from the staff on that.

MEMBER BARTON: I am confused. I'll never bring it up again, but I've got to understand where you guys are on this.

MR. NGUYEN: Yes, my name Duk Nguyen, and I'm from the License Renewal Branch, and I'm one that did the audit.

When this issue come up, the regional inspector go out there and look and say, fuze holder is passive, why don't we need some type of aging management program.

We look at that, and we hire a contractor, BNL, Brookhaven National Lab, to look at the fuze holder. We agreed that the fuel element is active, because it changed stage when it actuate, so that according to the rule this is not requiring the aging management program, similar to circuit breaker. The moving part or change state when actually the fuel element is out of scope.

MEMBER BARTON: What's out of scope?

MR. NGUYEN: Because it's active element. It's not required aging management review. It is globalized in renewal, but they do not require the aging management review because active elements.

MEMBER BARTON: Are you required to do anything with them after 40 years or not?

MR. NGUYEN: Because, you know, the fuel, when it blows, you know it, because it's active, okay?

MR. KUO: No, the fuel elements that is for what Duk said, it is active, and that would be taken care of by the maintenance rule, basically, we'd rely on maintenance rule to taking care of -- to take care of it.

MEMBER BARTON: Okay. So, everybody has it in their maintenance rule programs, and you know that for a fact?

MR. NGUYEN: I think that usually the fuel inside the motor control center, inside a breaker, and they have the preventative maintenance, every year they have the preventative maintenance to look at that load. Okay?

MEMBER BARTON: What do they do with fuzes, the fuze holders, do you know if they do anything? Have you looked at that?

MR. NGUYEN: This is a little bit tricky, because if the fuze holder is inside at the assembly, according to the rule we say that this does not require the AMR in the maintenance rule. The only fuze holder we worry about is the one that's outside active.

MEMBER BARTON: Suppose they are in a panel someplace, they are not in a motor control center or in a control room panel?

MR. NGUYEN: That control panel is supposed to be maintained by the licensee during the preventative maintenance, under maintenance rule, because it's important to safety, but according to the rule, license renewal, that assembly considered active, so therefore we don't require the aging management review.

MEMBER BARTON: Have you gone back to those licensees that committed to do something and told them they don't have to do anything, or are you going to let them fall off the cliff and come up with a program? Some people have said that they are going to do something, I remember that.

CHAIRMAN BONACA: The early applications.

MEMBER BARTON: Yes.

CHAIRMAN BONACA: They ended up with commitments on the passive element.

MEMBER BARTON: And, now you are saying now you agree that you don't have to do anything. Well, there's a bunch of people out there that are going to try to come up with some kind of program.

MR. KUO: No, I don't think that that's what Duk said. Yes, but they are fuze holders outside of the control panel, okay, and it's really isolated, it's just a fuze holder there, and then it is in scope and should have aging management program. That's what the ISG talk about. It's a very limited -- actually, when we had --

MEMBER BARTON: I get the impression that people are now saying they are not going to do anything with fuze holders.

MR. KUO: They don't have anything.

MEMBER BARTON: They don't have anything?

MR. NGUYEN: Most of the fuel holder inside the NCC, inside the panel. Very, very few cases we find it outside.

MEMBER BARTON: All right.

MR. NGUYEN: And, however, for the ones that are outside --

MR. KUO: At the beginning we knew that they were really a few fuze holders that might be subject to aging management program, because we are looking at only the isolated fuze holders. And, you know, like this happened at Peachbottom, okay, that was a big issue that the inspectors find that the fuze holders were --

MR. METELL: Okay, what does that mean? You all started to scare me when you say Peachbottom. Yes, it was my inspection.

CHAIRMAN BONACA: Are you the cause of all the problems?

MR. METELL: Yes, I am, thank you.

And, let me illustrate it in the case of Peachbottom. Maybe it would --

MR. KUO: Thank you.

MR. METELL: I tried not to step into this, they were doing just a good job.

In the case of Peachbottom, for example, what they are trying to say is that -- here's how that played out, so they did a search of all the fuze holders in the facility.

MEMBER BARTON: Okay.

MR. METELL: And, they swept through and found, if I recollect, 5,800 fuze holders, the pairs, that required some kind of scoping.

Out of the 5,800 they then swept through again and tried to find all of the ones that were part of an active program, maintenance, motor control, et cetera. So then, they eliminated those. Those were being held -- those were being maintained as part of an active program.

They then came up with a subset of fuze holders that were not partitioned off by these other constraints, they were not part of these other programs. They then reviewed all of those fuze holders for any activities or any history in the past for the fuze holder itself, including the kind of fuze that is actually bolted down.

MEMBER BARTON: Yes.

MR. METELL: It includes that as well.

So, they went through and they looked at all of the maintenance and history records for all of those fuze holders, to see if an aging management review was required, and they ended up with population -- this goes back some time, don’t hold me to the numbers, 512. There were -- once you got from the very large, there were very, very few programs, very few fuze holders, that required an aging management program.

And so, I can’t speak to what you’ve heard from other plants, but it wouldn’t surprise me that there are plants out there that you’ve heard, well, it wasn’t necessary for us to have the program, because we don’t have that small subset.

Does that help you, Dr. Barton?

MEMBER BARTON: I understand where you are coming from. I just think you may have inconsistency here in how people understand that, and some people coming through with some kind of programs and others not, and that’s what I worry about.

MR. NGUYEN: But, we look at the design and the technical justification, if the fuze holder -- that you have a -- fuze holder, and you never remove the fuze element, and the problem with the fuze holder we have found during the study, if people remove the fuze these people talk about, you know, low voltage, control voltage, where you move the fuze to re-energize the circuit to do the maintenance.

If you have a circuit breaker, and the design went to the energized circuit, you don't remove the fuze, you open the circuit breaker, then the fatigue and other aging effect.

So, it depend on each particular plan that we look at.

MEMBER BARTON: I understand the breakers. All right. I heard enough. I won't bring it up again.

MR. KUO: Thank you, Mike. I know why you are here.

MR. METELL: I'm sorry for ever having brought it up in the beginning.

MEMBER BARTON: Well, at least I know whose fault it is.

CHAIRMAN BONACA: All right, with that I thank you, gentlemen, for a very good presentation.

I'd like to ask the members again to give me their views.

MEMBER BARTON: I'm sorry?

CHAIRMAN BONACA: I'd like to ask your views of the application and what we heard today.

MEMBER BARTON: Well, my views of the application and the SER, well, I guess the SER, primarily, were I thought it was not a real good quality document, did not have good technical justifications for a lot of positions.

I think after today, hearing the presentation by the applicant, that I feel a lot better about, you know, the quality of this application and the condition of the plant.

I don't really have any problems with the application, and where I think the applicant is headed with his long-term programs.

I do think that, my personal impression is I think the NRC has got some work to do on the quality of some of the documents they put out, especially, from what I read in this application.

CHAIRMAN BONACA: You had some concern you expressed before to me regarding exceptions to the GALL.

MEMBER BARTON: Well, that's a tough one, Mario, because I think to try to eliminate the rising number of exceptions, you know, and what happens is, the people that are going to read Vermont Yankee's application, and everybody is doing that, so the guys that come down the pike say, well, they got away with 16 exceptions or something, I'll try for 24. I get a little concerned about that.

What made me feel a little bit better about the exceptions that Vermont Yankee had is, you know, they classified them into four or five different areas, all right, and they explained very clearly why each exception was "legit." And, I understand that.

To go back and change GALL, I don't -- you know, I guess we're halfway through the number of applications, maybe it's worthy to go back and change -- make some things -- some differences in GALL so you can kind of eliminate the number of exceptions I think that we are going to be seeing down the road.

Otherwise, we are going to be into this same issue we had with Vermont Yankee here, and maybe the next applicant is not going to come in and explain them as well as here today.

But, I understand there are exceptions in the categories, but I think we can do something with GALL to try and eliminate that.

CHAIRMAN BONACA: Okay, thank you.

Otto?

MEMBER MAYNARD: I thought the presentations by both the applicant and the staff today were very good, very informative. I think they had the technical back-up for the questions that were asked, and I believe they were prepared for discussing the questions that we could ask. I think it was very well presented, and very prepared.

The only issues that I would have are more generic in nature, gets back to GALL itself, and after taking a look at them there are two generic trends that I see. One is the increase or the number of exceptions, and I don't know if GALL needs to be changed, or whether we need to have a category where we classify them as equivalent to, or whatever, just so we can highlight which ones are truly exceptions to GALL versus which ones are just maybe a slight deviation to it.

So, I don't know if it's a matter of how we characterize it or rewrite each procedure. It would be good to get back to a point where we are dealing with pure exceptions that are truly exceptions to the methodology.

MEMBER BARTON: Which is really the

guideline document for license renewal. So, you don't really want a lot of exceptions. I agree, Otto.

MEMBER MAYNARD: And, the other thing I see is, we seem to continue to have a number of issues with the boundaries, and I don't know, again, whether that's because it's not clear as to what guidance is out there for the applicants, or whether each applicant's designs and drawings are so unique that it's just very difficult to -- but it always seem to be a number of questions come up on the boundaries that have to be going back and forth.

I think it might be beneficial in the future if we had a meeting with the staff, just on GALL itself. We've had a number of license renewal applications we've gone through and, perhaps, with the industry, and with the staff coming in, and give us an opportunity to see where they stand, and maybe for us to provide some of our input on maybe what they could or should be doing.

So, my comments are more generic along that line. I think as far as this applicant's presentation, the material and everything, satisfied me.

CHAIRMAN BONACA: Good, thank you.

What about your impressions?

MR. ARMIJO: Well, just on the issue of the exceptions, I think a lot of those exceptions are borderline technicalities, and others are -- shouldn't be labeled exceptions. If the staff believes they are equivalent or better than what's in the requirements for GALL.

So, I'm not so worried about the number of exceptions, perhaps, better terminology would solve that problem without having to go up and upgrade the GALL.

The exceptions should really be limited to things of substance, concern with the staff and the applicant had had some hard discussions to resolve.

MEMBER BARTON: Yes, that would help, to agree, you know, as to the basis for the exception, and, you know, its equivalent, but it's not written in GALL.

MR. ARMIJO: That's why it's satisfactory, and we rule on or we take our position whether we agree or not.

As far as the presentation, I focused on the materials of the plant. I think Vermont Yankee has done a very good job in the selection of replacement materials. I think they've done a very good job in assuring that the dry well shell and the torus shell are in good shape.

I think their commitment to using the hydrogen water chemistry technology to protect their materials I think is the right way to go, and their commitment to use that, that was something I heard late in the presentation, but if you'll ask the question I think that's a good commitment, and I hope you stick with it.

We did talk about the fatigue, and I'm satisfied that that can be handled more than one way, and the applicant is going to do that. I don't think there was very much detail in the application, and maybe that led to some extra work that wouldn't have been necessary otherwise.

Steam dryer cracking, I'm not -- it looks pretty good. I'm still a little confused on why you could get IGSCC up in a steam dryer, as opposed to a fatigue crack, but as long as something doesn't come flying loose, and create a loose particle problem.

MEMBER BARTON: I don't know, what's the quality of steam up there? Is it slightly super heater, or what steam up there?

MR. ARMIJO: They'll be some liquid, that was the testimony, but I don't know how long it could be there.

MEMBER BARTON: Okay.

MR. ARMIJO: And, if these IGSCC cracks were found after that first cycle of 20 percent uprate, if it formed that quickly I tend to believe it's more fatigue than a stress corrosion crack.

MEMBER BARTON: Right.

MR. ARMIJO: But, in either event, as long as they've done a loose parts analysis and says something won't come apart, it's not really a big problem.

Overall, I think it's a very good package.

CHAIRMAN BONACA: Okay. Said?

MEMBER ABDEL-KHALIK: I really have nothing to add beyond what my colleagues have said. I'd like again to congratulate the applicant and the staff on a clear presentation.

CHAIRMAN BONACA: Bill?

MEMBER SHACK: Just coming back to this exceptions thing, you know, most of the exceptions I saw were, I thought, fairly trivial. The one that was substantive, that sort of caught my eye, was the notion that you were going to do without the visual inspections on the ID of the core shroud, and, you know, staff negotiated that around with the licensee so that, in fact, they would follow the BWR VIP 76.

So, I mean, that was a serious exception to GALL, which I think was resolved properly.

The other ones, you know, I can't lose too much sleep over.

CHAIRMAN BONACA: Yes. I, for one, believe the presentations were very good, I appreciate the attention of the applicant, and for the staff.

I agree that the exceptions don't seem to be substantive, most of them. I think it is more the cosmetics maybe of what they convey regarding GALL.

Certainly, the last thing I would like to do is to have GALL become obsolete as to the exceptions, and I think, you know, again, that the burden probably is on GALL, and whoever maintains it, and I think that the industry and the NRC should at some point try to revisit that, and put into GALL the kind of latitude that is required to be more accepting of a variety of programs, and not -- it's nobody's fault, but at the beginning clearly we have had whatever experience we have reviewed.

Now, you know, they are doing so much more experience in power plants that, you know, should allow us to put that latitude inside the document to be more applicable to all the plants that we have, and that would reduce those number of exceptions that we have to take.

I agree totally on the issue of boundaries for scoping. We've seen it time and time again, and we have to deliver that 50 percent of the plants that come through still boundary issues.

I think one of the issues is actual drawings, to what level you have drawings that would describe systems in certain areas. That's not -- we have found that that's a challenge, and, you know, I was hoping that with the inspections we have on site that we should be able to solve it, and I think it is, ultimately, to come to an agreement. But, they have to physically get to it.

And, you know, I must say that I was impressed by the conditions of the plant. I mean, those pictures convey, you know, the measures of the torus in good shape, and dry well in good shape, too, and I think that's important, because it conveys a message about how the plant is being maintained.

And, with that, I have no further comments, except thanking all the industry and Vermont Yankee people and the staff for their support for the meeting.

Anymore questions, comments, on the part of Members or anybody else?

MR. JUNGE: What do you want to see for the full committee meeting?

CHAIRMAN BONACA: For the full committee meeting, I expect to -- first of all, I would like to have -- the meeting is to be a couple of hours.

MR. JUNGE: Okay.

CHAIRMAN BONACA: Hour and a half, okay, and I think that much of the presentation from Vermont Yankee was very informative. I think that, you know, with some maybe reduction, maybe, in volume, I wouldn't talk too much, you have three portions to your presentation. The first portion was more general about complying with improvements you've done, and so I would condense that somewhat.

The part on the license renewal is condensed enough, along with the slides, if I remember, so you don't want to condense it any further.

The information on the dry well and torus is very important, because they have been the object of our progress in other plants, and it gives us a clean situation. So, again, condense it to the level of the time that you have, but I think that's important to maintain, how you present that.

And, the staff pretty much what they

presented was very much to the fact.

MR. JUNGE: Thank you.

CHAIRMAN BONACA: So, are there anymore questions? No comments?

If not, I will adjourn the meeting. The meeting is adjourned.

(Whereupon, the above-entitled matter was concluded at 2:59 p.m.)