Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards
550th Meeting

Docket Number: (n/a)

Location: Rockville, Maryland

Date: Thursday, March 6, 2008

Work Order No.: NRC-2050 Pages 1-260

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

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

+ + + + +

550TH MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARD

(ACRS)

+ + + + +

THURSDAY

March 6, 2008

+ + + + +

ROCKVILLE, MARYLAND

+ + + + +

The subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., William A. Shack, Chairman, presiding.

PRESENT:

WILLIAM A. SHACKCHAIRMAN

MARIOV. BONACAVICE CHAIRMAN

SAID ABDEL-KHALIKMEMBER AT LARGE

GEORGE APOSTOLAKISMEMBER

J. SAM ARMIJOMEMBER

SANJOY BANERJEE MEMBER

DENNIS C. BLEYMEMBER

MICHAEL CORRADINIMEMBER

PRESENT: (CONT.)

OTTO L. MAYNARDMEMBER

JOHN D. SIEBERMEMBER

JOHN STEKARMEMBER

SAM DURAISWAMI DESIGNATED FEDERAL OFFICIAL

CHARLES BROWNNRC STAFF

GARY HAMMERNRC STAFF

C-O-N-T-E-N-T-S

P R O C E E D I N G S

(8:11 a.m.)

OPENING REMARKS

CHAIRMAN SHACK: The meeting will now come to order.

This is the first day of the 550th meeting of the advisory committee on reactor safeguards.

Here in today's meeting the committee will consider the following: license renewal application for the James A. FitzPatrick Nuclear Power Plant; license renewal application for the Vermont Yankee Nuclear Power station; selected chapters of the WER associated with the ESBWR design certification application; a subcommittee report regarding the license renewal application for the Wolf Creek Generating Station; and preparation of ACRS reports.

A portion of this meeting related to ESBWR may be closed to protect information that is proprietary to General Electric-Hitachi nuclear energy.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Mr. Sam Duraiswami is the designated federal official for the initial portion of the meeting.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's session. We have several people on a bridge phone line listening to the discussions related to the Vermont Yankee license renewal. To preclude interruption of the meeting, the phone line will be placed in a listen-in mode during the presentations and committee discussions.

A transcript of portions of the meeting is being kept, and it is requested the speakers use one of the microphones, identify themselves, and speak with sufficient clarity and volume so they can be readily heard.

I begin with some items of current interest.

Mr. Peter Wen joined the ACRS staff as a senior staff engineer on March 3rd, 2008. He has been with the NRC since 1982 working in several areas including event assessment policy and rulemaking issues and license renewal. Also he worked in Region 1 for six years.

Prior to joining the NRC he worked for Westinghouse for four years performing safety analysis of nuclear systems and Basco Services for four years working on nuclear plant design and construction.

Mr. Wen has B.S. and M.S. degrees in mechanical engineering from the Taiwan CD University and M.S. degrees in aerospace and nuclear engineering from the Georgia Institute of Technology.

Welcome aboard.

(Applause)

CHAIRMAN SHACK: Mr. Gary Hammer who has been with the ACRS staff for 18 months is leaving on March 18th to join the component integrity performance and testing branch in the Office of New Reactors.

During his tenure on the ACRS staff he has provided outstanding technical support to the committee and reviewed numerous regulatory and licensing matters including the ESBWR design certification application, several license renewal applications, digital I&C and fire protection matters; dissimilar mold metal weld issue; and several regulatory guides and generic letters.

His dedication, professional attitude, hard work and attention to details, in depth knowledge of regulatory matters, and willingness to assist others are very much appreciated.

Thank you, and good luck in your new job.

(Applause)

CHAIRMAN SHACK: Our first item of business is the license renewal of the FitzPatrick Nuclear Power Plant, and Mariov will lead us through that.

FITZPATRICK LICENSE RENEWAL APPLICATION PRESENTATION

VICE CHAIRMAN BONACA: Good morning.

We are here to review the final SER and the license renewal application of the James FitzPatrick NVP.

The license renewal subcommittee met in September 5th, of 2007, to review the SER with open items. At the time there were two open items. One had to do with fluence calculations that supported a number of TLAs, and the other open item was the environmentally assisted fatigue. The - both open items have been closed. The final SER has been received. And we are here to review it together with the staff and the licensee.

During the subcommittee meeting we reviewed the aging management program for the containment. There is a Mark I containment, including shell and torus. And we had a number of questions relating to some pitting identified by the licensee in the torus. I believe the licensee has dedicated quite a few slides today to address this issue, and because that is an area where the subcommittee has a number of questions.

With that I will turn to Dr. P.T. Kuo of the staff.

STAFF INTRODUCTION

MR. KUO: Thank you, Dr. Bonaca, and good morning to all members.

My name is P.T. Kuo for the record. I'm the director of the division of license renewal.

I also would like to introduce my staff who are responsible for carrying out this review.

To my left is Ronnie Framovich. She is the branch chief for the project management branch too, and to her left is Tommy Le who is the project manager leading the review of this application. And to his left is Glenn Meyer who is the team leader for the Region 1 inspection, for the license renewal inspection, at the plant.

Sitting in the audience we also have a Dr. Ken Chang. Can you show your hand please? He is the branch chief of the audit review of branch one who is responsible for the mechanical and the materials engine review area.

And we also have Dr. Raj Auluck who is the audit review branch chief two. His area of responsibilities are the structural and electrical engineering areas, plus scoping methodology review.

(Telephone interruption)

MR. KUO: We also have a technical - we also have technical reviewers.

CHAIRMAN SHACK: Do we need this now or is this just for Vermont Yankee?

(Telephone interruption)

MR. KUO: As Dr. Bonaca described, the staff has completed the technical review of the FitzPatrick licensing application, and we have forwarded to the committee the final safety evaluation report last month. And we have resolved two open items listed in the report to our satisfaction.

This morning we are going to brief the committee with the result of our review. And the presentation will be led off by the applicant first, and the staff's presentation follow.

With that, if there are no questions, I will turn over the presentation to the applicant first.

ENTERGY INTRODUCTION

MR. DIETRICH: Good morning. I'm Pete Dietrich, the site vice president at James A. FitzPatrick. And I'd like to thank you, Mr. Chairman, and the members of this committee for the opportunity to present our license renewal status to you this morning.

I'd like to introduce the members of our team. I'll begin with the gentleman at the front table, moving from left to right: Gary Young is a manager in our business development and license renewal group.

Next to him is Alan Cox, technical manager, also focusing primarily on license renewal.

Steve Bono is a director of engineering at James A. FitzPatrick and will be the lead for our presentation this morning.

Next to him is Joe Pechacek, our manager of programs and components engineering at the plant.

Immediately to my right here at the table is Brian Finn, our nuclear safety assurance director, and Jim Costedio, our licensing manager.

And sitting in the front row on this side Rick Plasse who is our licensing lead; Larry Leiter who is one of our technical leads at the facility; Thomas Moskalyk, structural lead; and Artie Smith who is our RSI engineer.

We figured for our discussion this morning specifically regarding the torus pitting these were the individuals to bring with us to answer any questions that the full committee has.

And with that I'll turn it over to Steve.

MR. BONO: Good morning. Again, thank you for the opportunity.

Just a quick agenda. Again I'm Steve Bono. I'm director of engineering at FitzPatrick.

We'll go through a brief site description, licensing history and some major improvements that we have done to the station; plant performance; and then also the making of our license renewal project.

We do as previously mentioned, we do have a special presentation based on our site committee topics that we'll go over our torus and our torus monitoring and the corrosion that we are monitoring in our torus.

We have some specific details. We were asked to bring some data in how we are evaluating the conditions that we have.

Just a quick briefing on the site. General Electric is our NSSS supplier; also a turbine generator supplier, and Stone & Webster was our AE and constructor.

We are a BWR-4 vintage plant with a Mark I containment, and we'll speak a lot about our containment later.

Rated at 2,536 Megawatts thermal which equates to about 880 megawatts electric, we are a once-through cooling system with Lake Ontario as our heat sink, and located on the shores of Lake Ontario. And right now our staff complement is about 660 people.

So just a brief licensing history. Construction permit issued in May of 1970. Operating license in 1974, and we began commercial operations July 28th, 1975.

As far as changes to our license, significant changes, in 1996 we did do a 4 percent power uprate, and uprated our license. In November of 2000 the license was transferred from the New York Power Authority to Entergy, owner/operator of the facility, and we submitted our license renewal application on July, 2006, and as noted our current operating license expires in October of 2042.

Some major improvements we made to the station: listed some here to give just kind of an idea of the types of upgrades that we do. I'm not going to go through all of these in detail. Many of these dealt with changes in the industry going through hydrogen water chemistries in conjunction with things to improve the asset.

I'd more like to point out that the processes that we identify as major capital improvements in a 15-year plan, we call that our asset management plan. So we look ahead 15 years.

Some highlights as we look forward for

our asset management plan.

CHAIRMAN SHACK: Those look like hardware changes I'd make if I was planning a sizable power uprate. Is that in the works?

MR. BONO: The question is, is power uprate in the works for FitzPatrick? I can tell you we are embarking on a feasibility study right now. We need to know the results of that feasibility study before we can commit that power uprate is immediately in our plans.

Some of these items, turbine rotor replacements, some of that was due to steam path losses, so when you see those they would appear to be gauging for the future. But we had in our HV turbine we were monitoring by a phased array, we had some indications, and in our low pressure turbine rotor we had some steam path losses.

So those were the driving influences for those replacements, although they do, as you record, they do match well with if we were going to upgrade the facility.

But some highlights as we move forward, we are looking at the age of some of our large motors. That is an issue that we have plans to resolve, motor degradation over the next couple of years.

Here we're looking at a research pump overhauls, both pump and motor, as original plant equipment. We're at the point where those are aging.

Condenser retubing, just being on the shores fo Lake Ontario, that's a frequency established to go and retube our condenser.

And then also a scheduled transformer replacements with our main transformers and our aux transformers.

MEMBER ARMIJO: What is the condenser tubing material?

MR. BONO: Right now the condenser tubing material is two part; the higher tubes up in the steam path are titanium, and the other tubes are brass, an admiralty brass material. So with that comes certain chemistry concerns that we matter. Right now all below any established chemistry guidelines or limits. But we will reevaluate the material as part of the retubing to give us better chemistry performance.

CHAIRMAN SHACK: So the material to retube has not been chosen as of yet?

MR. BONO: The material to retube has not been chosen at this point.

Any other questions on our master management plan or looking forward?

Current plant status, plant is operating today, plant is operating today at 100 percent power. It's been operating for 117 consecutive days.

Just big picture, we are in a cycle. We started up from our refueling outage in the fall of 2006, and we have a refueling outage scheduled for this fall.

Coming out of that refueling outage we did have a 250-day run which is the longest for a FitzPatrick history to come out of an outage with that length of run. We view that as a measure of the quality of the work we do, and also the scope of the work we do to maintain the equipment systems functioning well.

So some of the items of interest in this outage. Some we've covered specifically in our asset management plan. But one is our main transform replacements, and we are tracking that as an end-of-life item. So we are replacing those transformers.

Our core spray motor replacements, our

core spray system, one of our ECCS systems, is original plant motor; we're monitoring that. No known degradation right now, but that is just more of managing the aging.

And then we have a yard breaker, again no degraded condition in our switch yard. But the breaker is sized to prevent single faults, and right now the duty on that based on changes in the grid, we need to change that to meet the conditions of our ISO agreement with our grid suppliers.

And then we have some screen house upgrades. This last fall we went through a period where we saw some environmental changes, and we had some algae intrusions that we had seen at FitzPatrick historically.

We have made some upgrades to the facility to address that. But we've got some more upgrades that we are planning, and also to replace our screens from the age and condition of the screens.

So there are some screen house upgrades that we'll do as an asset management improvement.

In our license renewal project we do have a project team that is experienced. It's multidisciplined, and it's also an Entergy fleet team, so it utilizes both a corporate process but also our own onsite technical lead and onsite resources.

The benefit of doing this as a fleet is, we've incorporated lessons learned from the other applicants, and we have some of the Entergy fleet that is further in the process than we are for license renewal. So we've incorporated lessons learned from that. And we also get feedbacks from their audits and their inspections.

So learning becomes a continuing process within the Entergy process, and that continues even after our original amendment submittal. An example of that is another facility had some scoping concerns over spatial effects. Based on that feedback we went and did additional walk downs at FitzPatrick and we confirmed that we had done the proper scoping.

So that was a way we took a lessons learned from another facility and applied it back even though our amendment had been in to make sure we had no additional concerns.

VICE CHAIRMAN BONACA: Those were the scoping issues at the BY?

MR. BONO: Those ere the scoping issues at

Vermont Yankee. So we'll hear more about that in BY's presentation.

We do some internal reviews, both a safety review committee and quality assurance as well as our own peers, using our Entergy processes. And all internal comments are resolved prior to submittal of the amendment.

As part of our project we did review our application and evaluate against the goal. We identified that of the 36 programs, 10 were consistent. Twenty were consistent with some exception or enhancement, and then six were plant specific.

We're tracking all of the commitments in an Entergy commitment tracking system that has oversight and requires elevated levels of management closure, or approvals, before they can be closed.

VICE CHAIRMAN BONACA: The majority of programs have had exceptions. Could you comment on the complexity of dealing with that? Because if I looked at them and the corespondents, with the NRC, the IRIs and all the discussions going on is another world.

Did you find Gall too prescriptive, too

narrow?

MR. COX: Let me try to answer that. The exceptions were fairly minor - my name is Alan Cox, by the way. I think I introduced myself.

The exceptions we had again in a lot of cases were fairly minor, things such as the code year. I believe at the VY presentation we went through and tried to categorize these things, and I think we had very similar exceptions in the FitzPatrick case.

Steve mentioned there were 20 programs with enhancements or exceptions. A lot of those were enhancements instead of exceptions, so it's making the program consistent with the Bell report.

Again, I don't think we had a lot of trouble dealing with it. Some of the things were cases maybe where the GALL was prescriptive in terms of code year or addition. Some of them were the same exceptions that we talked about that you heard about yesterday.

The standards for diesel fuel monitoring, it's just a little bit of ambiguity in GALL if you will, because it represents two stacks when one of them may be all that applies to your particular plant. In general there were a few exceptions, but they didn't present any major problems for us.

MR. BONO: And as I mentioned, we have 25 commitments at the end of our evaluation. There are 36 aging management programs. We currently have 17 programs in place without enhancements. Nine programs that are in place but will require some enhancement. And we have 10 new programs.

One aspect of being a fleet here and with boiling water reactors of similar vintage, we are looking at the commitments from the other stations in developing programs in kind of a fleet approach. We'll be able to use the resources from both Pilgrim, Vermont Yankee and ourselves to come up with programs that we can write program documents and implement as a fleet.

Just to go over as stated our draft SER was issued in July, 2007 with two open items . Those items were reactor vessel fluence. An update on that issue: we did revise our calculations, and they've been updated to meet Reg. Guide 1.190. Those were being approved through our processes, and submitted in November. And those have been reviewed and accepted.

In the environmentally assisted fatigue area, we have established a commitment where we will comply using our fatigue monitoring program, using the NRC approved version of the code. So we will refine our analysis of the cumulative usage factors, and then establish corrective actions to prevent exceeding any design limits during the period of extended operations.

So we've established that as a commitment. That will be done two years prior to the period of extended operation.

Final SER was issued in January of 200. And as noted both of those items have been closed, so it was issued with no open items.

MEMBER BANERJEE: How are your steam dryers doing?

MR. BONO: We do monitor our steam dryers using our vessel internal program.

MR. PACHACEK: Lee me just - my name is Joe Pachacek. I'm engineering programs and components manager.

Our steam dryer overall is doing very well. We have completed a very detailed inspection based on better as-built drawings. It's been one of the challenges in the industry identifying all the welds that come back. We did do our last outage, an as-built on the dryer, completed our inspections.

We do have several indications. The last outage we actually did a repair, it was on an upper vertical weld where we had several pieces of metal stuck together.

Overall though compared to what's been seen in the industry our dryer is in very good condition.

CHAIRMAN SHACK: Those indications you attributed to SCC?

MR. PACHACEK: I don't - Ms. Gallic, can you comment on that, whether it was a GSCC?

MR. COSTEDIO: I believe those indications, I believe they are fatigue related.

MEMBER ARMIJO: At the last subcommittee meeting we had a lot of discussion on that, whether they were IGSCC or fatigue related. And there was some skepticism on the part of the committee members on how could you tell with just a visual surface inspection whether something was IGSCC or fatigue.

I'm not sure it really matters since you will be monitoring the components anyway. But at some point it wouldn't hurt to have General Electric or whoever made the assessment for you to give you a nice white paper on why they believe it's IGSCC in a few cases.

MR. PACHACEK: That is a good comment, and we'll capture that comment and follow up on it. Thank you.

CHAIRMAN SHACK: I mean if you are doing a condition assessment, the crack growth rates are going to be quite different.

MEMBER ARMIJO: Right, but in the final analysis, is sit enough to make a difference from your inspection to your -

CHAIRMAN SHACK: Well, you might have to inspect more frequently if you thought you were dealing with fatigue rather than IGSCC.

MR. PACHACEK: And just to clarify a point, too, that the NSSS providers, since General Electric was very involved in it and actually performed the assessment of the last indication we saw on the operator was the dryer, and they did make a recommendation to repair it.

That indication was fully excavated and

weld repair was effected.

MEMBER ARMIJO: Okay, just on the issue of your reactor vessel fluence, after all this was said and done, and you finally have a fluence calculation that the staff agrees is correct, where did you wind up compared to the original fluence calculations? Were the original fluence calculations that you submitted much more conservative? And could you give me kind of a ballpark level of -how different were the two analyses?

MR. BONO: What I do have is, I have all locations. I'm not sure I can fully answer your question, but I can turn it over to my technical staff.

I do have information that all areas were considered with the exception of one areas, the lower intermediate shell, and the location is shell two, the surface fluence was 3.11 e^18th was the condition we ended with, but all other areas, our existing calculations were more limited than the revised.

MEMBER ARMIJO: That was the only one where the original estimate was nonconservative?

MR. BONO: The original was 3.05 e^18th; we went to 3.11.

(Laughter)

MR. BONO: Everything else moved in the other direction.

MEMBER ARMIJO: Okay, I don't worry about that.

MR. BONO: The change, pretty minute. But that was the only one that had a change in the other direction; I'll say that.

MEMBER ARMIJO: Okay.

MR. BONO: Any other questions on our open item?

As we talked about in our subcommittee meeting, we had lengthy discussion on our torus. Again this is more to depict the Mark I containment. Obviously the area that we'll be talking about is the torus.

The torus has a 30-foot cross-section diameter across the torus. I've got some data as we approach this that will show the indications that we're monitoring, their locations and where they are below water level.

VICE CHAIRMAN BONACA: Before you get to the torus you may want to say something to the whole committee regarding the condition of the shell and the program you have. I mean, do you have a plan to do that?

MR. BONO: Yes, I have a plan to go into detail on the condition of the shell, torus shell.

VICE CHAIRMAN BONACA: That's only the torus. I'm talking about the drywall. Because then we had a subcommittee present information about a drywall that was positive, clearly indicated that it was in good condition, and you justify your aging management program, particularly you have a leakage monitoring system and so on and so forth.

MR. BONO: We have a leakage monitoring system where any leakage when it reaches a certain threshold is enunciated. We have done - fluoroscopic, thank - fluoroscopic inspection in our sand drain areas and found no moisture.

And we do a caulk seal inspection every refuel outage. And that has - we've got no known degradation of the caulk seal.

VICE CHAIRMAN BONACA: And you have had no bellow leakage?

MR. BONO: No identified bellows leaking events at FitzPatrick.

VICE CHAIRMAN BONACA: Okay.

MR. BONO: And like I said, our inspection of the sand rains indicate no evidence of moisture. We've done boroscopic inspections. Most recently, in 2007 we've done a boroscopic inspection of that area.

VICE CHAIRMAN BONACA: For the benefit of the other members of the committee, I mean we reviewed this in detail, and we got a positive impression. So we emphasized that the presentation to the full committee should focus mostly on the torus. But the committee has -- members had said that the shell program was good.

MR. BONO: Tom or any other technical people, anything you'd like to add there? Any questions?

Focusing in on our torus was the issue where we were asked to bring more information, more data. We do have a ton of work regarding our containment inspection, in service inspection program. It does implement the IWE code provisions.

As we note here our requirements from ASME Section 11, the 2001 edition, through the 2003 addendum.

So we do have a program that is built off the code requirements. Some different inspection criteria. I wasn't going to go through a lot of these. I was going to kind of focus more on what we're seeing.

But we do do our general visual once every period, our wetted surfaces once every interval, and our event system once again 100 percent once every interval.

Moisture barriers, 100 percent during each inspection period. Containment surface areas, we do a detailed visual; 100 percent of surface areas identified. And then we do have a surface area grid where we use ultrasonic testing, and I'll go into this in much greater detail.

But we do 100 percent of the minimum wall thickness locations that we have identified. And then we've established each of those based on the code sections referenced there.

VICE CHAIRMAN BONACA: First of all, the previous slide, you mentioned accessible surface area once every period. And then you talk about once every interval.

Could you explain what period and intervals are?

MR. PACHACHEK: Arturo Smith, if you would address the question regarding intervals and inspection frequency please.

MR. SMITH: I'm not sure I understood the question. Could you repeat that please?

VICE CHAIRMAN BONACA: You have the statement below those bullets, once every period. Below that it says, 100 percent once every interval. And again, interval. Would you explain to the committee what period and intervals are?

MR. SMITH: Those intervals-period is in accordance with the code, which is 3-1/3 rd years. Each interval is 10 years based on the ISI program. And it's broken up into three periods within that 10 years.

FitzPatrick currently has five years within an ISI interval, and we have broken that up into two outages, one in the period, one in the second and two in the third.

So the period is equivalent to 3-1/3 years. An interval is equivalent to the 10 years.

VICE CHAIRMAN BONACA: Okay. Now you - this is a standard IWE program, but you have identified some level of pitting throughout the torus. Could you describe that, and also how your program is adopted to that?

I mean when you have findings typically you enhance your program, right?

MR. BONO: I think we will go through that as we move forward. I do have a slide that depicts the location of our fitting, the magnitude of it, and then also how we go about - that those identified areas increase monitoring.

MEMBER BANERJEE: What is the material of the torus, carbon steel?

MR. BONO: Carbon steel.

MEMBER BANERJEE: So this is what, pitting that you see in the carbon steel? What is the reason for the pitting?

MR. BONO: Water.

MEMBER BANERJEE: Yeah, but water and what?

MR. PACHACHEK: Wet surface, yes.

MR. MOSALYK: The torus is coated with carbo-zinc 11. It's an inorganic zinc coating. The inorganic zinc depletes over time, and the result of the depletion, pits form in certain locations.

MEMBER BANERJEE: Do you have an idea what has happened to that zinc coating over a long period of time? Has it tinned, or has it just tinned in specific spots? Or what has happened there?

MR. MOSALYK: Well, it has thinned over time. During 1998 when we had a torus drain down, and desludging a bit at that time, there was a very extensive inspection performed of the entire torus, lower section, wetted surfaces.

One particular area of interest where there was a water zinc depletion, there was an inspection done of that entire area, a pitting inspection done of that entire area, and the pitting, there was some pitting in that area, not very significant, about zero four, about inch-deep pits. So it did not reduce the shell much in that area at all.

Other areas we segmented the torus into - we have 16 bays. We have five shell plates in lower sections for each bay, and we segmented each one of those five shell plates into six sections. So we have about 480 sections, that we actually inspected and determined defects in those areas.

So we have a clean map of the lower section of the torus. It's kind of a baseline map that was used for subsequent routine inspections.

MEMBER BANERJEE: How do you determine the pit depths?

MR. MOSALYK: The pit depths in 1998 were determined with visual pit gauge readings. Inspections were done for all the segments, all 480 segments, using pit depth gauges.

Subsequent to that during - we've been using ultrasonic examinations in the areas of interest, the pitted areas of interest.

MEMBER BANERJEE: How big are these pits in diameter?

MR. MOSALYK: The diameter of the pits? Well, they vary somewhat. We have not gotten to a point where we have needed to characterize the pits in a lot of detail because we are still well above our normal design limits. We have a limit for general thickness for the torus. And at this point even the deepest pits are still well above that point.

MEMBER BANERJEE: What is that point?

MR. MOSALYK: Our design point is point five zero three inches. We have a nominal shell thickness of .632 inches. Specification, the material specification, the A516 Grade 70 plate steel is allowed to be provided in thicknesses up to point zero six thicker than the nominal.

We are finding that many many of our plates, for the most part almost all of our plates, the actual plate thicknesses that were supplied are well above that point. And we determined that by ultrasonic examinations.

MEMBER BANERJEE: So did I hear you right that the pits can be as much as half an inch deep?

CHAIRMAN SHACK: No, a tenth.

MEMBER BANERJEE: What did I hear?

CHAIRMAN SHACK: A tenth, maybe.

MR. MOSALYK: Our pit depth, our actual pit depth to date has been .076 inches, tracking from - yeah -

MEMBER BANERJEE: Point zero seven six.

MR. MOSKALYK: Correct.

MEMBER BANERJEE: And your current depth is, the largest pits is point zero four you said? I'm totally confused. Please repeat. What have you found? What is the limit? And what is the pitting?

MR. BONO: Okay, what we have found is, our maximum pit depth of all the areas we've mapped and all the areas we've ultrasonically examined is

.076 inches.

MEMBER BANERJEE: Okay, and what is the limit?

MR. BONO: Our limit is .503 inches. That is our design requirement for general thickness.

MEMBER BANERJEE: That is half an inch, right?

MR. MOSKALYK: That's the plate thickness.

MR. BONO: That is the required plate thickness based on design analysis.

PARTICIPANT: What Pedro is asking is, what is the maximum pit depth that you can tolerate.

MR. BONO: Okay, the maximum pit depth we can tolerate.

MEMBER BANERJEE: Exactly.

MR. BONO: Okay, the maximum pit depth we can tolerate, what, nominal thickness - we know our plates are thicker than that, but if you took the nominal thickness and subtracted .503 it would be .129 inches. That would be from nominal.

I think we have a slide coming up that goes through a lot of this, so you can visualize it.

MEMBER BANERJEE: Okay, that'll be -

MEMBER MAYNARD: The pit depth is as

important as how much metal do you have left. Your wall thickness can vary, so it's not so much the pit depth, because you may - it be occurring in a thicker or it could be in a thinner. It's how much metal is left below the pit.

MEMBER BANERJEE: Yes, what I'm interested in is understanding what margin you have, and how long it's taken you to eat that margin out, you know, sort of extrapolating that experience. So you are going to talk about this?

MR. BONO: I think we have a slide coming up that presents the data in a way that will - that visualizes it better that I think will help in this area.

So I think, Tom, we can go through a lot of the data when we get to that slide, so we do -

MEMBER BANERJEE: So let's defer it.

CHAIRMAN SHACK: Well, you are also comparing at this point to nominal, and you could actually have much greater localized depth information.

MR. BONO: And we have found that our plate thickness, although nominal as Tom presented, like I said it's as high as 10 percent above nominal in many locations. So that's why the UT measurements becomes a very accurate way of monitoring where we stand compared to the design limit.

MEMBER MAYNARD: I think when we get to that point what we need to talk about is, what is the minimum wall thickness required, and what is your current minimum wall thickness that you have. That's where you get how much margin you have.

VICE CHAIRMAN BONACA: The other issue is, you know, how many pits do you have in a certain area. Because you may have just one location, and so the wall is still solid and capable; and you have a pinpointed one. Or you may have significant pitting in an area; then you worry about - so those are pieces of information you'll want to give us.

Now I know you do have a slide to address the specifics of that.

MR. BONO: That's correct. I think a lot of this will come together. We've got a slide that I think represents this data in better detail. We've just got a couple of sundry slides I need to work through to get us there.

From a summary statement, we haven't identified any interior, exterior surfaces areas that have substantial corrosion or pitting.

I say substantial corrosion or pitting, as kind of a measure of when we would meet the code required threshold for augmented inspections. So we have not reached any of those thresholds.

We have no areas that are excessive wear from abrasion or erosion that's caused a loss of the coatings, deformation, material loss. And I think Tom explained why we are seeing the pitting based on the zinc depletion in our coding system.

VICE CHAIRMAN BONACA: So let me understand the mechanism now. You have this coding depletion, and if it goes beyond a certain amount of depletion, you expose the metal. And then you have pitting forming from that.

And it seems to me that certainly you are going to monitor new areas where you may have that happening, and I think you are addressing that later. But also I would like to know what your corrective actions are. Because I mean if I understand it you have left the uncovered material exposed to the water, so you must have some idea.

So I trust you have a monitoring program. But the question I have in my mind is, is your corrective action appropriate. What are you waiting for before you record those portions? I mean that - if - answer that whenever you get there, but that's something I need to understand.

MEMBER BANERJEE: Also, for me I need to understand the mechanisms. Is it a zinc oxygen redox couple that's forming? Or how is it - you know zinc-oxygen makes a little battery. So if you walk me through that it would be useful.

MR. BONO: And when we get there, Tom, I'll ask you to help us with some of the technical issues.

We have identified 29 locations, so it was asked how many locations we had. We've got 29 locations on the interior surface of the torus. Again, it was referenced, and they are below the code threshold for augmented inspections.

What we have implemented is kind of an increased monitoring, which we do more frequent examinations based on these locations so that we can understand the rate and how much margin we have in our plate thickness.

MEMBER ARMIJO: Just to make sure I understand, are all these pitting locations at the waterline, below the waterline, above the waterline, or all over the place?

MR. BONO: I think when we go to the next slide, I think this might help to visualize it. This is a picture looking down on the bottom half of our torus. So these are the plates. Our torus is segmented in 16 bays. There are five plates per bay, and then we've sectioned each plate into a six-section grid that we can use for monitoring.

So you can see in these locations that as you move on the inner or outer diameter of the circles here you're getting closer to the water level, because you are looking down on the bottom.

And as you're in the middle of the diameter, then you are looking at the bottom of the torus. So we're looking down on the bottom half of the torus.

MEMBER CORRADINI: Just so I understand, so you're unwrapped it, so if I look at the inner radius I'm at the bottom of the floor. So if I look at the outer radius of the donut I'm at the top of the torus?

MR. BONO: This is - imagine this is like a cross-sectional view looking down on the torus.

MEMBER BANERJEE: The plan view.

CHAIRMAN SHACK: The middle of the donut is the bottom.

VICE CHAIRMAN BONACA: My understanding, and tell me if I'm correct, is that the pitting was in the weathered area?

MR. BONO: Yes, this is all - the water level is about one foot from the center line of the torus.

VICE CHAIRMAN BONACA: I was just asking the other question.

MEMBER ARMIJO: Yeah, so you are not seeing any pitting above this.

MR. BONO: Areas above the torus when we operate our containment system is inerted with nitrogen. We don't have the environment that really produces corrosion above water level. That is inspected 100 percent every outage we do a visual.

MEMBER ARMIJO: Is the whole torus coated?

MR. BONO: Yes.

MEMBER ARMIJO: All surfaces, whether it's below water, above waterline?

MR. BONO: Yes. The entire course of the torus is coated with the same Carbozin system, four to nine mils thickness, original application.

MEMBER BANERJEE: So point zero four nine inches; is that it, the thickness?

MR. BONO: The thickness, four to nine mils for original dry thickness application.

MEMBER BANERJEE: So some of these pits have actually gone through the full thickness of the coating?

MR. BONO: Of the coating.

MEMBER BANERJEE: Yeah, do you see any acceleration over time of the pitting, or has it been sort of uniform over time?

MR. BONO: I think to answer that I need to go through a little bit more of the history and see if we can answer that through the presentation.

In 1998, as Tom said, we did 100 percent visual, and we did fit gauge measurements of all these locations.

What you see on the left of the donut is kind of our inspection period with each mark, and then also as an example above that you can see how we designate an area.

So it'll be bay followed by plate, and then the actual UT exam thickness reading.

So as Tom discussed, our plate nominal thickness is .632 inches with a designed minimum thickness of .503 inches for the lower half of our torus.

Now the plate nominal thickness -

CHAIRMAN SHACK: But again that would be general corrosion. So you could have even localized deeper than that. That would be a conservative estimate of your margin.

MR. BONO: Yes, if I understand your comment is that when we say the plate design thickness minimum, that's the entire torus. And we apply that design requirement to a localized area because we feel that's conservative.

And as Tom displayed, we have seen variations as high as plate thickness of .69 inches. So -

MEMBER ABDEL-KHALIK: What's the design basis for the .503 minimum thickness?

MR. BONO: Tom, question is the design basis for the .503 inches, the design basis? What are the assumptions?

MR. MOSKALYK: The design basis is based on ASB Section 3 code and is the number of load cases you consider. The most limiting that is used to establish that number if membrane and bending, membrane stress, bending stress, combination produces .503. There are other combinations that would produce thicker results, but that is the most limiting.

MEMBER ABDEL-KHALIK: Is the set point for the water level in the torus, has that ever changed?

MR. BONO: Not to my knowledge. Larry? No, the set point has not changed; maintained the same torus water level through -

MEMBER ABDEL-KHALIK: Does the water get stagnant in the torus or does it move around?

MR. BONO: Other than, you know, we do a lot of surveillance testing where we run our systems that might draw suction or discharge into the torus, I wouldn't necessarily say the water level is stagnant, because we do do a lot of surveillance testing, required surveillance testing of our ECCS systems.

MEMBER ABDEL-KHALIK: So what is the frequency of stirring it up, roughly? Once a year? Twice a year?

MR. BONO: We run some of our safety

systems quarterly that would stir this up. At a minimum I would tell you that the steam discharges in the torus, quarterly, we run those safety systems that use the steam that would discharge in the torus.

MEMBER STEKAR: Do you have a suppression pool cleanup system that's normally running?

MR. BONO: No, we do not have a torus cleanup system. We monitor torus sludging. We do an evaluation. And then we schedule a de-sludge of our toruses during outages.

So I can go through the schedule here in a minute. I will point out that right now our most limiting location - and as we said, we apply our most limiting localized area as if it were across the whole torus - our most limiting location would give us remaining surface life out to 2026. So we have that.

We do have in our asset management plan provisions that we would address this before we reach design limitation.

MEMBER ARMIJO: That is assuming a linear continuation of where you are now?

MR. BONO: That's assuming a linear continuation. We do have a schedule, and it's listed on there, right there, as we go back.

We are going back to some of these ultrasonic that would give us more of an ultrasonic to ultrasonic point to give us - so we could refine that. And if that projection changes we'll take corrective action

MEMBER BANERJEE: The point of my question was, did you see some acceleration in the finding of your pits? And since when did you start this monitoring program? How long have you had it in place?

MR. BONO: We've had this monitoring program since the 1998 drain down where we identified these pits.

MEMBER BANERJEE: So in 1998 you found some pits. And since that time you found more pits, right, or have you?

MR. BONO: To my knowledge we haven't identified any new locations since 1998. 1998 was our last torus drain down, removed the water. We can do underwater inspections, but that was the last opportunity where we had the water dry.

CHAIRMAN SHACK: Was that your first drain down?

MR. BONO: No, we had down drain downs prior to `98 when we had done the Mark I containment modification.

CHAIRMAN SHACK: Which was when?

MR. BONO: 1979 and 1983.

MEMBER BANERJEE: But then you had some repairs in 2005?

MR. BONO: I'm sorry?

MEMBER BANERJEE: You had some repairs in 2005. Did you have to drain the torus when you fixed that break?

MR. BONO: No, we had a torus indication based on stresses from our IPSE discharge line, which was the - in the subcommittee presentation we had a thru-wall indication in our torus because of a very localized stress was our IPSE steam line. And the manner in which it discharged into the area without a sparger on it.

So we've gone, we've taken corrective action at the design deficiency, put the sparger in. But we had to repair the area. We actually did not have to drain down to do that. We were able to do an underwater repair.

VICE CHAIRMAN BONACA: Right, but so what you said before however is that you have not inspected new areas.

MEMBER BANERJEE: It's not that you haven't found; you haven't tried in the last 10 years.

MR. PACHACHEK: Tom already talked about the size of the UT grids that we do that would essentially provide an enhanced inspection area, similar to what we discussed at the subcommittee meeting.

MR. MOSKALYK: We performed a thorough inspection in 1998 of the entire torus, the entire wetted surface of the torus. And that provided a baseline for our future inspections.

From that point we categorized the number of pits, there were 29 locations we categorized for, we eventually prioritized future inspections for those locations.

Of course the deepest pits we inspected with ultrasonic first, and we are now working on priority twos and priority threes which are more shallow pits.

We do reinspections of the areas of the deepest pits. We'll be repeating inspections for our deepest pits this coming refueling outage.

MEMBER BANERJEE: So the ultrasonics that you have been doing have been looking at, say, how these pits are changing with time? You are doing that?

MR. MOSKALYK: That is correct.

MEMBER BANERJEE: So are you finding any acceleration rather than a linear behavior with regard to both the depth of the pits as well as the number of the pits over time?

MR. MOSKALYK: We've got the pits, we have performed - we are just now going to be performing ultrasonics in the same location a second time. So we had visual data from 1998. We performed ultrasonics in a number of areas. We are going back to repeat several areas for a second time. So from a standpoint of ultrasonic inspections and measuring using the same method, we will just be performing our second ultrasonic this coming outage in the deepest pit areas.

So that'll establish an actual pit growth rate. We have the pit gauge measurement from 1998 and ultrasonic from, if you look at the schedule, some 2004, 2006 locations, and then we'll have a second ultrasonic so we can better establish and refine that pit growth or loss of material rate, and then we can refine our extended service life.

VICE CHAIRMAN BONACA: So what you are saying is that you have not in every location repeated your ultrasonic testing yet?

MR. BONO: Right, we have the original pit gauge measurements. We have ultrasonics, and in the fall, this outage, you can see we've got scheduled repeats from areas in 2004 as well as our most limiting bay that we identified in 2006, we are going back in.

VICE CHAIRMAN BONACA: You are planning to develop a rate, a progression, that you will use in your program? I mean is it defined in your program that you will do that?

MR. BONO: Yes, we have an engineering evaluation that we have a calculation that we will refine, and that's what - like I said, we take the minimum thickness and apply that generically to the whole torus. We feel it's conservative. And then that comes up with the remaining surface life. And then we have plans to take corrective action prior to the service life.

VICE CHAIRMAN BONACA: But the question I have in my mind, still, as you said, that in the worst location you project 2028 for the possible failure.

MR. BONO: 2026, that's correct.

VICE CHAIRMAN BONACA: Reaching the criterion. So for that one you seem to have developed a rate of progression which you are using.

MEMBER BANERJEE: Assumed a linear rate.

VICE CHAIRMAN BONACA: Okay, a linear rate. Now the question I have is, when are you going to take action? I mean what criteria do you have for intervention to mitigate this situation?

MR. BONO: We do have an approved coating program, Tom, that is an underwater repair for areas. We do have that approved. We do have that ability to do that.

Maybe you can go into more - we've got priorities established in our calc, and we are looking at where we would hit design thickness, and then we would plan back from that to do a coating repair.

MR. MOSKALYK: We do have a qualified coating system for underwater repairs if we need to do that. As a matter of fact we applied that coating system to the area which we repaired near the IPSE sparger discharge that same system. That system is used by a number of plants; it's been effective. And that would be our plan for these areas.

CHAIRMAN SHACK: How big are your ultrasonic grids? When you're looking at these things, how much of an area are you looking at?

MR. SMITH: How we set up these grids, we have these pit locations, or at least these degraded areas that we've found. And then around that we'll open up a 3X3 or 2X 2 and then we'll scan these 100 percent. We don't actually take point to point readings, but we actually scan 100 percent of this, although it is gridded, so we'll know if we find any -

MR. BONO: So we have a three foot by three foot grid, and we will do 100 percent scan in that grid.

MEMBER ABDEL-KHALIK: We are covering a lot of surface.

MEMBER MAYNARD: But you are not recording each - and you are recording a result of those scans. If you find an indication in that area that you would go back and do more specific at that point?

MR. SMITH: That is exactly what we would do. We define that, and then what we would do is take specific readings around it to get a rate of the thickness in that area to see if there are any other instances of it occurring.

MEMBER SIEBER: The scans are from the outside in?

MR. BONO: Correct.

MEMBER SIEBER: So the surface prepped and all that kind of stuff does not disturb it?

MR. BONO: That is correct.

MEMBER ABDEL-KHALIK: These original measurements were done with a depth micrometer?

MR. BONO: The 1998 measurements, that's correct.

MEMBER ABDEL-KHALIK: How do those compare accuracy-wise with the ultrasonics?

MR. BONO: Tom, do you have that information.

MR. MOSKALYK: Pretty close. Our deepest pit that we determined in 1998 was point zero eight inches. Deepest pit in our subsequent inspections using ultrasonics we established a .076. It appears that the visual pit depth gauge measurements appear to be a little more conservative from the standpoint of showing a little bit deeper pits.

MR. PACHACHEK: Just if I may too, just to clarify a previous question that was asked, whether or not our program includes requirements to take any new - any changes in the UT data as far as pit depth and incorporate that into the program, the answer is yes.

So we would redo the calculation to reproject from in-service life whenever we have any new information that's gained as a result of doing UTS on the shell.

VICE CHAIRMAN BONACA: And you have identified the corrective action that you will implement?

MR. BONO: That is correct. And we would also track that in our corrective action tracking system.

MEMBER BANERJEE: If necessary you could record the whole thing, right?

MR. BONO: If necessary, that's correct.

MEMBER BANERJEE: So what you are really doing, you are using these 29 locations as leading indicators.

MR. BONO: That is correct. We are using those as leading indicators, and as I stated, we're applying that to the whole torus for getting remaining service life.

MEMBER BANERJEE: So this is part of your aging management programs?

MR. BONO: This is part of our containment in service inspection program, that is correct.

MEMBER BANERJEE: And you have sort of identified certain things that would lead to you need to repair ceratin areas, and eventually perhaps even recoat the whole thing if necessary, as part of your program?

MR. BONO: That's correct, that's part of the program. That's why we project the remaining surface life so we can take that corrective action before we hit any design limit.

CHAIRMAN SHACK: Of course as you mitigate each of these areas with a protective coating you've lost a leading indicator.

MR. BONO: That is correct. Now one thing I should point out, in 2010 we will be doing a torus de-sludge operation that will - we will also 100 percent underwater inspection. And that is also the best opportunity to patch any areas, when we have a de-sludge operation.

CHAIRMAN SHACK: Now the 100 percent underwater that's a visual? You go in with a boroscope, basically?

MR. PACHACHEK: Divers.

MR. BONO: Divers.

MR. PACHACHEK: Divers that are qualified in accordance with the necessary ND programs for visual inspections.

MEMBER SIEBER: But it is still a visual.

MR. PACHACHEK: It is visual.

MEMBER ABDEL-KHALIK: But the logic of this whole program assumes that all the sort of pitted locations had been identified in `98?

MR. BONO: We are using the pitted locations in `98 as kind of a leading edge indicator. In 2002 - or I'm sorry, 2010 when we do the de-sludge, obviously, we will have new data that we will then use as inputs into our evaluation.

VICE CHAIRMAN BONACA: And that will tell you if you have additional locations that are developing. Now that would also be the opportunity to determine in fact that you have identified leading indicators, that have some other location where you have something happening and you don't know.

MR. BONO: That is correct.

MEMBER BANERJEE: I guess this is a very nonlinear process, because once you go through that zinc, things start to move much more quickly right? Or not?

MR. BONO: I don't know that I can say that. What I can tell you is that we've got the - we use the pit depth measurements to an ultrasonic to establish a rate, then we'll go back with another ultrasonic and refine our rate.

We are using a linear right now because we have two points. But as we get more data we'll revise that, and we'll be able to project a much more accurate rate.

MEMBER BANERJEE: But just from the point of view of logic, the coating is there to prevent the initiation. Once you go through the coating things are going to go much faster, right? You would think so.

MEMBER SIEBER: If you get pitting, the coating has already lost its integrity.

MR. BONO: You will begin corrosion from the point of the loss of the coating.

MR. LEITER: This is Larry Leiter from FitzPatrick System Engineering. The advantage of zinc is that it serves as a sacrificial anode, and so it will to some extent fill in its own gaps. The zinc coating doesn't have to be continuous. Minor flaws don't - minor flaws can personally correct themselves. They will redeposit. What happens though is that the pit that forms that has penetrated through the coating now behaves as a pit and corrodes in that manner.

MEMBER BANERJEE: What I known of zinc electrodes, you start to get dendrite formation on deposition.

MR. LEITER: You can.

MEMBER BANERJEE: So how is this coating repairing itself?

MR. LEITER: It's the - you have the large expanse of zinc, the entire coated area, so it can deposit back in.

MEMBER BANERJEE: Explain this to me in some detail. Is this a common thing that you expect this to repair itself by electrodeposition?

MR. BONO: Our program monitoring is using these as leading edge, and then we establish a rate through the ultrasonic.

MEMBER BANERJEE: Yeah, I see what you are doing, which is fine. But I would have thought that the rate would accelerate, I mean just looking at the physics of what is going on, or the chemistry in this case.

But Bill is much more of an expert on this.

MEMBER MAYNARD: I need to take a step back here and make sure I understand.

When we're talking about a pit depth, are we talking about a pit in the coding or a pit in the actual metal?

MR. BONO: Metal.

MEMBER MAYNARD: Okay, so when we are talking about a pit, we've already gone through the coating?

MEMBER BANERJEE: My understanding is that the pitting starts because you have lost the coating.

MR. BONO: That is correct.

MEMBER SIEBER: There is no mechanism to accelerate that, once you've breached it.

MEMBER MAYNARD: The other thing, on your program for corrective action, does it require action before exceeding all your margin? Or does it require action before say 80 percent of your margin is gone?

MR. BONO: Right now, Tom you can correct me if I'm wrong, but it requires corrective action before exceeding the design margin. I don't know that we have a threshold established at 50 percent or 70 percent of design margin.

We obviously are looking at the opportunity to do a torus repair, torus coating, is in refueling outage, so we'll be projecting years so we could plan and execute that activity.

MR. MOSKALYK: The inspections we do in 2008, reinspecting 10 locations that had been previously inspected, and that information will provide us with a pit growth rate. From that point we can make determinations as to what corrective actions we would take when it would be appropriate.

MEMBER MAYNARD: If it's not in your program I would suggest that you at least consider - you don't want to be in a situation where you are projecting right on the limit, and you go to that limit and you go in there and find out you had exceeded it a little bit. A lot of programs, you really take action before you reach the limit.

VICE CHAIRMAN BONACA: Absolutely. I mean that - you know, that is an essential element of any aging management program is in fact when you start your corrective action how do you mitigate this situation.

We are projecting by linear extrapolation that you are going to go through, you are going to exceed the limit.

MR. BONO: We'll get to it, a localized area on that where the pit would be less wall required that our design of the entire torus.

VICE CHAIRMAN BONACA: You don't want to get that close.

MR. BONO: I understand. I understand the input, and I said we can refine the program to add a criteria at what point to take corrective action. We're projecting in a manner to plan and execute this I think that we account for that. We don't plan on going into an outage to get these types of measurements, and obviously if we have to we'll take action.

But we are trying to project it in a

manner that we will do it before we reach design limits.

MEMBER BANERJEE: But minimum thickness is based on your projected local loss?

MEMBER SIEBER: As we pressurized it.

MR. BONO: That is correct. The design minimum, .503 plate thickness, is based on - assumes some loads, and that's based on our local loads.

MR. MOSKALYK: Primarily based on pressure and hydrodynamic loads. So the hydrodynamic loads are evenly distributed. They are not a local condition.

CHAIRMAN SHACK: No, he meant loca or main steam line break. What axis is the limiting load.

(Simultaneous speakers)

MEMBER BANERJEE: Why do you assume it to be evenly distributed? Because you are getting bubble collapse, right, where you are injecting. And this bubble collapse gives you very strong pressure waves.

So why do you assume it to be uniformly distributed?

MR. MOSKALYK: Well, uniformly distributed because the condition would be for the downcomers into each of the bays. The downcomers are evenly distributed throughout the entire torus.

MEMBER BANERJEE: How many downcomers do you have?

MR. MOSKALYK: Forty-eight parts, 96.

CHAIRMAN SHACK: Does this thing lose the nitrogen inertia in an outage? Or is it always - when does it become oxygen saturated or air saturated?

MR. BONO: During outages.

CHAIRMAN SHACK: During outages.

MR. BONO: During outages we do an above-water-level inspection and our containment -

CHAIRMAN SHACK: Is open to the atmosphere?

MR. BONO: - is open to the atmosphere and de-inerted.

CHAIRMAN SHACK: So you pick up air every fueling outage then?

MR. BONO: Every two years, and then when we re-inert.

MEMBER ARMIJO: When you re-inert, do you do any kind of sparging of the water to get rid of dissolved oxygen and CO2 from the water, exchange it with the atmosphere in the gas phase if you will? Because without oxygen you are not going to have any corrosion.

So is there anything in your plan to actively keep the water as minimally aggressive as possible?

MR. BONO: I don't - you guys, I'll ask my technical team to back me up, but I don't know of any - where we planned a sparging of the torus. We do do - as I described before, we do do quarterly surveillance testing where we do stir up the torus, and we do have alutions like that. But it's not what I would call a plan.

MEMBER ARMIJO: So you don't transfer the benefits of inerting from the gas phase into the water phase where you have the problem?

MR. BONO: Not in the planned fashion I think you are asking.

MEMBER SIEBER: You still have dissolved oxygen in the water to some extent?

MEMBER ARMIJO: You'll have some. But if you took advantage of the nitrogen you did have you might save yourself a lot of grief later on.

The other issue is, do you have - is the worst pitting concentrated under the sludge area, away from the sludge area? Where is the problem more severe, or most severe?

MR. BONO: I don't know that we could say - we could correlate that. And Tom, I don't know if you can help. I don't know that there is any correlation to sludge location and pitting location.

MEMBER ARMIJO: But just tell me, where are your deepest pits, and where are they on that map?

MR. BONO: It's in the indigo bay is one that we identified in 2006. Again, you say deepest pit, we use the minimum wall thickness; that's our least amount of wall thickness. And we are going back, we identified that in our 2006 outage, and we are going back to that location in our coming outage.

MEMBER ARMIJO: Where would that be on this map?

MR. PACHACHEK: It would be here.

MEMBER ARMIJO: Of that's near the bottom. Potentially it could be a sludged area.

MR. BONO: Potentially; I don't know that we have a correlation that would suggest that.

MEMBER BLEY: The orange spots here is

your schedule for doing the inspection? Or the locations? You don't have a map like this of where you found the pits?

MR. BONO: These are the locations.

MEMBER BLEY: Oh, those are where the pits are? So you can tell, they are not all down in the bottom.

MR. BONO: That is correct.

MEMBER ARMIJO: But the point is, you ought to know where your most severe problem is, and you ought to know the mechanism that is causing the pitting, and it's not generalized, so it's not a homogeneous environment there underneath that water level.

And the question comes up, do you have any kind of a chemistry model for this torus either by your contractors, consultants that are telling you, this is from a first principle, this is where your problem will be most severe. This is what you should do to monitor it or actually mitigate it without waiting umpteen years to get to the edge of a cliff.

And it just seems like there is a lot more information that you could get to protect this course rather than just monitoring and inspecting it once in awhile.

MR. BONO: We do not have a chemistry model to answer that question. And during our 2010 de-sludge operation I think we'll get the kind of data you're looking for as far as locations compared to conditions in the torus at locations.

MEMBER BANERJEE: What is the sludge, generally? The composition of the sludge?

MR. BONO: You guys can you help me there, the composition of the sludge?

MR. MOSKALYK: I don't know, it would be corrosion products.

MEMBER BANERJEE: Zinc and iron oxides. Some carbonates?

MR. MOSKALYK: I don't know about carbonates.

MEMBER BANERJEE: Oxides maybe?

MR. MOSKALYK: Oxides, correct.

MEMBER BANERJEE: Well, carbon dioxide. It would be interesting to know.

Because does the - do these react with boric acid and things?

CHAIRMAN SHACK: There's no boric acid.

MEMBER BANERJEE: But they inject during the - in an accident.

MR. BONO: We have some accident scenarios where we inject boric acid.

MEMBER BANERJEE: Clearly -

(Simultaneous speakers)

MEMBER SIEBER: Once you do that, you'll be doing a lot of other things.

MR. BONO: It hasn't been done at FitzPatrick, nor do we plan on doing it.

MEMBER SIEBER: This represents 30 years of degradation.

MR. BONO: That is correct.

MEMBER BANERJEE: The reason I'm asking about the sludge, of course you de-sludge, is, are there any potential reactions between the boric acid and the sludge? The Germans have identified some reactions.

MEMBER SIEBER: There is no boric acid.

MEMBER BANERJEE: No, during the injection. CHAIRMAN SHACK: He's got an accident going on, and he's putting in the boric acid.

MEMBER BANERJEE: I'm worried about the

long term cooling of this system.

MEMBER SIEBER: After an accident?

CHAIRMAN SHACK: After an accident, yeah.

MEMBER BANERJEE: I'm always worried about accidents. Not worried otherwise. So what happens now? You've got boric acid in there. You've got this sludge.

MR. BONO: I'm not aware of any interaction. I'm not prepared.

MEMBER SIEBER: Actually, the degradation that would occur due to the boric acid, the transient pressures the container.

CHAIRMAN SHACK: I think he is worried about generating some gases.

MEMBER SIEBER: The chemical reaction.

CHAIRMAN SHACK: Or reacting the sludge with the boric acid.

MEMBER BANERJEE: We are drawing from the sump to cool the system.

MR. BONO: Yes, it's a make up water source through a strainer, ECCS systems have a strainer designed to ensure we get net positive suction into the ECCS systems.

MEMBER BANERJEE: You are going to talk a little bit about the strainer system as you go on or not?

MR. BONO: I had not planned on it. Again our presentation was focused on managing the aging in this condition of the torus.

MEMBER BANERJEE: Are these disc strainers that you put in?

MR. BONO: They are disc-type strainers for the ECCS strainers, that's correct, for our safety systems.

MEMBER MAYNARD: They did cover that in detail in the subcommittee meeting, and we went over that a lot.

MR. BONO: We talked about the strainer system because of the thru-wall indication we had. Again, we covered that because - to show that that was a design flaw, not an aging condition that needed to be managed.

MEMBER BANERJEE: Anyway, if there is a problem it'll be a generic problem. It's not your problem.

MEMBER ABDEL-KHALIK: Typically when you do these sludge removal operations, how much sludge are you talking about? Tens or hundreds of kilograms?

MR. BONO: Tom, do you have that data as how much, when we do a de-sludge operation? It is based on ECCS strainer loading, and -

MR. MOSKALYK: Total sludge weight? Dry weight of sludge will be approximately 3,000 when we do the de-sludge in 2010?

MEMBER BANERJEE: Three thousand what?

MR. MOSKALYK: Three thousand pounds, approximately 3,000 pounds dry sludge weight.

MEMBER BANERJEE: It's a lot.

PARTICIPANT: Is that physical process, or do you have to acid clean to get that stuff out?

MEMBER BANERJEE: It plugged up the strainers before.

MR. MOSKALYK: It's silty.

MR. BONO: It's like a - it's silty, so it's filtering. And then when we dry the filtering is the weight that Tom is talking about.

MEMBER BANERJEE: This was evenly distributed in the submerged depths, what thickness of metal would it correspond to, 3,000 pounds?

MR. BONO: Oh, the 3,000 pounds.

MEMBER BANERJEE: Just the mass balance,

evenly.

MEMBER SIEBER: That's not all metal.

MEMBER BANERJEE: Well, it's oxygen and metal. Take out the oxygen. So remove the oxygen from the mass.

CHAIRMAN SHACK: It's coming from somewhere, right.

MEMBER BANERJEE: So what would be the thickness of that? Do we have an idea of that? Three thousand pounds, so let's say an oxide. You could back-calculate it, right? Is this just a mil or two or what is it?

MEMBER MAYNARD: If it's generalized.

MEMBER SIEBER: That's not all coming off the torus there. That's coming basically out of your entire steam system, feedwater system, everything.

MEMBER BANERJEE: That's true.

VICE CHAIRMAN BONACA: In the next slide you make a statement regarding inerted nitrogen. Could you -

MR. BONO: Just - I think it's a point we made earlier that our containment, 95 percent, other than every two years, is inerted, with the nitrogen environment so that the systems above water level are not prone to a corrosion or a corrosion atmosphere.

And then again just a summary statement that our system, we look for the monitoring of these surfaces, and we mitigate any degradation and coding issues.

As I said before we take a localized area and we apply it to the whole torus when we calculate our remaining surface life.

MEMBER ABDEL-KHALIK: How many data points do you expect to have for the depth of these pits before the end of the current license period, 2014?

MR. BONO: We list our schedule there. We will have 100 percent underwater visual in 2010.

MEMBER ABDEL-KHALIK: No, but I'm trying to extrapolate as far as pit growth rate. How many data points do I have at the worst location to be able to extrapolate, to get anything better than linear?

MR. BONO: At the worst location we will have the pit depth measurement, we've got one ultrasonic. We've got an ultrasonic in 2008. The results of that will prompt us that, you know, if required we will do a two-year inspection to refine that number of points and project out that.

So we'll have one every two years between now and 2014.

VICE CHAIRMAN BONACA: By the way, on a separate note, I mean we are going to have a presentation from the staff, and the inspectors looked at this problem so we'll hear about it.

MEMBER BANERJEE: When you say linear extrapolation is it linear from the time the pits were found, which is `98? Or linear from year zero?

MR. BONO: We have a linear from year zero, but we refine that as we get - so we have the pit depth; we have the ultrasonic; we'll have an additional ultrasonic; so we'll refine that.

MEMBER SIEBER: Well, you started off with a nominal thickness which may be large or small.

MR. BONO: And again with the localized area and the way we do our ultrasonic, we've got a good idea of the actual plate thickness.

MEMBER BANERJEE: The main thing is that you will find the problem hopefully before anything develops. This is the assurance we need.

MR. BONO: Right, and again, in 2010 we will have 100 percent underwater visual that will identify all areas.

MEMBER BANERJEE: So this thing is not going to fall apart under a loss of coolant accident?

MR. BONO: I would not - I can say that this will not fall apart during a loss of coolant.

MR. COX: I think there is one key point that I wanted to point out here that we've kind of been beating around, the criteria is based on the measurement of a pit. So when we get to the minimal wall thickness for that pit we are not out of margin, and it's not - I'm not able to easily quantify it, but there's a large margin in the fact that you are looking at a pit and applying that depth or that wall thickness as if it applied to the whole area in that bay of the torus.

MEMBER SIEBER: You have a membrane type calculation.

MR. COX: And again that is not clearly - not something I can clearly give you a qualification of and tell you what percent margin that is. But it's a very large margin.

MR. MOSKALYK: Local fitting, if you look at the local condition, we use AS&E code case, N480, and it provides guidance as to how establish the minimum thickness requirements at pits. And pit lengths, so there are characteristics of the pits, pit lengths and depths are used in that calculation.

And you can go much lower than that depending on the characterized - you know, the dimensions of the pit.

We are not using that. We don't expect to be using that. But that is - that still provides a code allowable method fo accepting pits below your minimal wall.

VICE CHAIRMAN BONACA: We need to move on now.

MR. BONO: We have one more slide, and it's kind of a summary to a lot of what I've just presented.

We do do general examinations monitoring torus surfaces. We evaluate those conditions in an approved engineering process of calculation, and we extrapolate a localized area to the entire torus.

And then when we do our de-sludging in 2010 we will do another 100 percent underwater visual. And then we monitor those points using ultrasonics in our program.

VICE CHAIRMAN BONACA: Any questions for the applicant?

There are none. I thank you for the presentation. And we will hear from the staff now.

MR. BONO: Thank you.

MEMBER BANERJEE: You got away without a diagram showing all these thicknesses.

MR. BONO: I think the best data we have is what I provided.

MEMBER BANERJEE: But I was just saying a diagram of these things. I'd like to see the thickness of the wall, the pits, minimum, something like that. Something.

NRC STAFF REVIEW SUMMARY

MR. LE: Good morning, Chairman, Dr. Shack. My name is Tommy Le, and I'm a senior project manager in the division of license renewal, Office of Nuclear Regulatory Commission.

With me today I have Mr. Glenn Meyer, he'll be coming up soon. And I have Mr. Roy Matthew, who is a team leader for the NRR audit team. And then in the audience I also have a scoping team leader, Mr. Billy Rogers.

With that introduction I would like on

behalf of staff I'd like to thank you, Mr. Pete Dietrich, the vice president, of FitzPatrick Nuclear Power Plant and his management staff and engineering staff for having hosted the staff several audit inspections and many conference calls in the facility. And of course we finished the audit before three feet of snow that came about after.

On behalf of the staff I would like to say that I appreciate enormously the staff who had reviewed the FitzPatrick license renewal application. And it's to their credit that the information is now compiled in the safety evaluation, the open SER, open-item SER we issued back in July, end of July, 2007. And we issued the final SER on January 24 of this year.

With that I would like to first go over a summary of what we did during the September 2007 sector meeting. During that time we reported to the subcommittee that the audit team had compiled 346 audit questions, and the technical staff have 118 IEI. And the -with the audit evaluation and input from the audit and safety review we issued the SER with the open item on July 31st, 2000 with two open items, no confirmatory item, and three standard license conditions.

MS. FRANOVICH: Tommy, this is Ronnie Franovich with the NRC staff. I can't find Glen out there, so why don't you go on to your slides on the NRC staff's evaluation, and then we'll come back and cover the regional inspection when he gets here.

MR. LE: Thank you.

Along with that I would like to go on to section two, scoping and screening review. And that would be on slide #9. The scoping and inspection team have performed the audit, and the conclusion fo the audit team was that the application information had included scoping and screening methodology that are consistent with the requirement of 10 CFR 54.4 and 54.21(a)(1).

The onsite audit was performed during the week of September 25 to 29 of 2006. And the staff concluded that the SSC was within the scope of license renewal and the subject of aging management review consistent with the requirement of 51.4 and 54.21(a)(1).

On Section #3, this is the heavy work for the NRR audit team. And we reviewed a total of 26

AMP program, with 18 men in a program, of which we had 26 existing AMP and 10 new AMP. Two of the 10 new AMP were at the finding of the staff, and communication and two were added.

For the consistency with the law the applicant have planned consistent quantity, consistent with either exception, enhancement, in the six plant-specific program. The result of aging management review is that the audit team come up with 346 audit questions. And all questions except two were resolved onsite during the interfacing with the applicant engineering staff. Two questions of which were converted to IEI, one became a new aging management program that we needed, and the other became an open item.

The two open which I will return to during the subcommittee meeting was, one was the fluence calculation, and the other was environmental assisted corrosion.

And so we will resolve that in Section #4. At the end of the AMP and AMR audit there were a total of 25 commitments submitted to the staff.

MR. KUO: Tommy, just to correct the record, you said environmentally assisted the corrosion. It is not. It is environmentally assisted fatigue.

MR. LE: Oh, yes, I'm sorry. Yes, thank you, Dr. Kuo. With all these dignitaries it kind of make me humble.

(Laughter)

MR. LE: Section #3 conclusion based on the review of the AMR and AMP the staff concluded that the applicant had demonstrated that the effect of aging was adequately managed so that the intended function would be maintained consistent with the CLB for the period of standard operation.

At this time I would like to turn over to Mr. Glenn Meyer, who will talk abo9ut the regional inspection, and then I will finish up with the Section #4 PRAA.

MR. MEYER: Good morning. I apologize for my late arrival. I was checking with my peers on torus corrosion.

But I led the inspection that was done in April of 2007. We basically had two purposes. We addressed the scoping of non-safety related structure, systems and components, and we also looked at the implementation of aging management programs.

Within the scoping area our focus was those non-safety SSCs whose failure could affect safety components.

We looked at both the spatial interaction and structural interaction; did the review by means of reviewing the application drawings, looking at the program procedures that they had, doing considerable walk-downs of considerable areas that were safety and non-safety to confirm the thoroughness of the job they had done.

We did find some components and portions of systems that they agreed needed to be added to within scope, and there was an application amendment to accomplish that.

Overall the spatial interaction was generally thorough. The structural interaction was sound, and we concluded that the scoping and screening within our area of review met the regulatory guidance and properly supported Entergy's license renewal application.

MEMBER BLEY: May I?

MR. MEYER: Sure.

MEMBER BLEY: I wasn't at the subcommittee meeting. Can you tell me a little more about what you look for in the spatial and structural interaction?

MR. MEYER: All right. On your license renewal they have non-safety systems and components -

VICE CHAIRMAN BONACA: Seismic? Go ahead, I'm sorry.

MR. MEYER: Two over one can be part of it, but the bulk of it tends to be, or spatially, would be fluid systems that are in the vicinity of safety systems and their failures, the fluids could affect the safety systems.

And then a second component is the structural part where they have attachments, typing that is non-safety but it's attached to a safety system, and the structural design includes structural supports on the non-safety part. So they have to extend the license renewal boundary into some part of the non-safety system.

VICE CHAIRMAN BONACA: And then from what you've told us you just found a few areas where they had to look a little further than they had. No inconsistencies means where they looked it seemed okay.

MR. MEYER: Right. The general approach

was sound. We found a few areas that they had to amend.

The second area was aging management programs. And we looked at 22 programs to take a look at the program implementation, both in terms of the programmed procedures they have, the operating experience evaluations, the records of prior corrective actions that they have identified and addressed to get a sense of how effective the programs were or would be; also talk to the cognizant people in terms of their understanding; and also went into the plant and looked at systems as evidence of how the programs were working.

And it was a mix of existing and proposed programs.

Regarding aging management we concluded that their aging management program support the conclusion that aging effects will be managed. We are part of the process, the regional administrator letter to NRR, the NRR office director in January stated our determination that Entergy had demonstrated the capability to manage the effects of aging during the period of extended operations.

VICE CHAIRMAN BONACA: With regard to the torus, the inspection report says in fact that you have evaluated their aging management program, right?

MR. MEYER: Uh-huh.

VICE CHAIRMAN BONACA: And what is your judgment on that?

MR. MEYER: We do look at the - it's controlled by the ASME code, so we have periodic inspections under the current license where we go in and look during outages at the inspections they perform; the conclusions they draw, and the records and evaluations.

Our review during license renewal concluded that they're meeting their existing commitments. And part of their application for saying what they're going to do looks to be effective.

So it is something we periodically look at, and we also look at during license renewal, and found that the FitzPatrick program has been generally effective and met the regulations.

MS. FRANOVICH: Dr. Bonaca, if I could add, the staff, the technical staff and headquarters makes a determination of the program's acceptability. So the tech staff from NRR may be able to answer that question on how we determined the program was effective.

Really the regional inspection looks at, is it consistent with what they told us in the application.

VICE CHAIRMAN BONACA: Okay.

MR. LE: Thank you, Glenn. Any questions for Glenn?

I would go on with the report to the full committee, the staff review of Section four TLAA. TLAA, the plan specific safety analysis that involved time limiting assumptions defined by the current operator and must be listed in -- it was Section 54.21(c)(1) of any plan specific TLAA bay assumption, a code requirement of 54.21(c)(2).

The - we - the staff look at the criteria that all the SSC involved should be in the scope of license renewal as both requirement of 54.14(a), consider aging effect, involving the time limit assumption defined to an operating term determined by the applicant by making a safety determination, and involve the conclusion and provide the basis for conclusions related to the capability of the SSC to perform the intended function and code requirement of

54.4(b).

And lastly they had to contain or incorporate by the reference in the current licensing basis.

With that criteria in mind, the staff reviewed the TLAA and we identify two open item that was reported to the subcommittee. One had to do with reactor vessel fluence, and the original submittal were not adhering to the reg guide 1.;190, and mentioned previously by the applicant.

And so the staff identified this as an open item on November 5th, of 2007. The applicant provided the staff with a new calculation based on the guidance of reg guide 1.190, and the NRR staff we had Dr. Lambert Lewis who had looked at it, and he concluded the methodology acceptable, and the new value that is presented in the new report, bounded by the initial value, and for that open item that we have in the question, we would answer.

The second open item is the environmentally existing fatigue, and this now has been resolved. During the review the applicant had provided the staff with commitment 20. In that commitment the applicant had committed to comply with

10 CFR 54.21(c)(1)(iii) that mean that they will have an aging management program to manage this environmentally assisted fatigue.

With that we resolved the two open items, and so for Section conclusion, the staff conclude that for 10 CFR 54.3, the TLAA had listed adequately as amended, and for 54.21(c)(1)(I), analysis remain valid for the period of standard operation, or PEO, and for (ii) the analysis projected by the end of the PEO and for (iii) aging effect was adequately managed for the period of standard operation.

And so the staff also concluded that sufficient supplement to SAR had also been provided as a requirement of 54.21(d). And the applicant had no plan-specific exception called for in 21(c)(2).

In the next slide is the nominal standard three license condition that the staff has imposed on every renewed license once approved by higher management.

The first license condition would require the application to include the UFSAR supplement required by 54.21(b) in the next UFSAR update as required by CFR 58.71(e) following the issuing of the renewed license.

The second license condition require future activity identify in the UFSAR supplement to be completed prior to the period of standard operation.

The third license condition require that the applicant in the reactor vessel that are removed or tested will meet the requirement of the ASME 185-82, that they stay practical for the configuration of the specimen in the capsule.

Any changes to the capsule withdraw schedule, including spare capsules, must be approved by the staff prior to the implementation. All capsules placed in storage must be maintained for future insertion. Any change to the storage requirement must be approved by the staff as required by Appendix A to Part 50.

With that overall conclusion, the staff say that there is reasonable assurance that the activity authorized by the renewed license will continue to be conducted in accordance with CLB, and that any changes made to the FitzPatrick Nuclear Power Plant CLB in order to comply with 10 CFR 54.29 in accordance with the act and the commission's regulations.

With that the staff conclude its briefing to the full committee, and we have a technical expert standing by if you had any questions.

MS. FRANOVICH: Dr. Bonaca, at this time if you would like the staff member who was responsible for reviewing the torus aging management program is at the table, Hans Ashar. He can address why the staff determined that that program was acceptable.

CHAIRMAN SHACK: Good, let's hear that.

MR. ASHAR: I am Hans Ashar from the Division of Engineering, NRR. I heard a number of questions from the CRS members, and I'm trying to grasp everything that was being asked, and I'm trying to answer some of these questions if not all of them.

First thing as far as the torus corrosion is concerned, let me give a slight history on how it is, in the industry in general.

First time we heard about the torus corrosion was 1988 or so, where Nine-Mile Point had uncoated torus, and it was getting corrosion, and they informed us about the corrosion. And we looked into it based on what we understood from that particular plant.

But as we went along in 1992, 1993, the IWE program was not available even at that time because we had not endorsed it. We heard about a couple of other plants where they said they had coated torus and still it was getting corrosion in a few spots.

And we started looking at more and more plants. And we said, hey, the tori in most of these plants has some kind of corrosion. As a matter of fact I have seen a couple of plants where the numbers of pits in the torus is higher than 9,000.

And how-

CHAIRMAN SHACK: The coated plants?

MR. ASHAR: They are coated. They are coated, yes.

This brought us to quite a bit - this happened to a number of other plants that we already reviewed before, that actually FitzPatrick has only 29 locations where they are to monitor, they can monitor, isolate it. They don't have to have a plan and everything worked out.

But when there are a lot more locations we have reviewed them, and we have said that, hey, your program - now I'm going to come to what are the items you - basic requirements that addresses this particular idea.

First thing the IWE requires that whenever they find corrosion or corroded areas, whether it is a drywall, a containment, BWR containment, BWR, it doesn't matter, IWE allows them to have a 10 percent corrosion of any kind without any questions asked. Okay, this is the acceptable criteria in IWE.

If they go over 10 percent they are to do engineering evaluation or take corrective actions, okay. Now, in case of torus in drywell shell in Oyster Creek, you heard a lot about drywell shell corrosion, what happens is that they normally do the engineering evaluation. And that is where they come out with certain criteria and say that, hey, we are going to meet - this is my minimum required thickness. I'm going to meet it before it gets to that particular point.

IWE also requires them to monitor those areas where corrosion have been found through two successive inspections to make sure that the thickness is there and not progressing, and they are to take - if it is progressing they are to make sure that the corrosion rate is established, and then they can propose the particular corrective action and take the corrective action at that time.

Now when I looked at the program, the IWE program in FitzPatrick case, I saw that they told us in operating expedience that there are three locations that they found a little slightly higher than design thickness requirement. And I looked at the figures, I so the corresponding IWE requirements, and I said, hey, the program if it is to be appropriate, the way they are handling and monitoring the particular areas are quite okay.

And that was my basis for accepting the IWE program that FitzPatrick has given to us. We have some few questions on that, but they satisfactorily answered those questions.

VICE CHAIRMAN BONACA: What you are saying is that the IWE program contains the typical criteria that you would expect in an aging management program?

MR. ASHAR: That is correct.

VICE CHAIRMAN BONACA: Altering intervals, et cetera. So that is helpful. Thank you.

MR. MATHEW: Let me follow up - this is Roy Mathew - the bore gives guidance regarding how you manage the torus and drywell corrosion. It says you have to use two aging management programs, which is in-service inspection IWE program, and also the leakage monitor program for CFR Appendix J.

So we reviewed these two programs, and following that we reviewed their operating experience too. Since they follow the goal guidance, and the program is consistent with our guidance, we don't have an issues.

VICE CHAIRMAN BONACA: Okay.

MR. MEYER: And I would like to add from the inspection perspective, we did look at the containment in-service inspection program. I believe the inspector is Michael Modus who has spoken to you on other occasions, and has a lot of experience in the field. His writeup in the report said, the torus degradation has been occurring for several years. However Entergy has performed appropriate inspections, analysis and repairs to demonstrate the structural integrity of the torus. Entergy's program contains requirements to continue inspections of the containment, evaluations of the observed degradation, and prediction of remaining service life during the original license period and throughout the period of extended operation.

He said that - you know we do in Region 1 have a number of Mark I containments, many of which were built without coding and are dealing with similar issues. And what we see from FitzPatrick tends to be better than some of the other approaches. They are all acceptable, and we feel that FitzPatrick has done an appropriate job.

VICE CHAIRMAN BONACA: Good, thank you.

Any other questions for presenters? If not, I give the meeting back to you.

CHAIRMAN SHACK: We are just a little bit ahead of schedule, five minutes. But we'll go ahead and take our break until 10:45.

(Whereupon at 10:22 a.m. the proceeding in the above-entitled matter went off the record to return on the record at 10:44 a.m.)

CHAIRMAN SHACK: I think we can come back into session.

Our next topic is the final review of the license renewal application for the Vermont Yankee Nuclear Power Station.

And Dr. Bonaca is lucky enough to lead us through this again.

FINAL REVIEW OF LICENSE RENEWAL APPLICATION FOR

VERMONT YANKEE NUCLEAR POWER STATION

VICE CHAIRMAN BONACA: It was kind of hard to keep FitzPatrick and Vermont Yankee apart.

We met a month ago to review the application for license renewal for Vermont Yankee. And I believe we covered pretty much every item of the agenda having to do with license renewal.

There was one remaining item that was left because of the time; we did not have a final SER. And it has to do with the environmentally assisted fatigue calculations.

I would just summarize very briefly what has happened since. Entergy has chosen to address environmentally assisted fatigue by demonstrating that CUF and the most sensitive locations would remain below one throughout the period of extended operation considering both mechanical and environmental effects. The analysis performed by the licensee are supported also by assumptions that will be monitored and verified during the period of extended operation.

The analysis performed by the licensee

had confirmed that in all locations CUF is going to be below one throughout the period of extended operation. This staff however has challenged the use of the simplified methodology used by the licensee for those locations which exhibit geometric discontinuities or no symmetric loads such as the feedwater nozzle for example or the circulation out that nozzle and the coarse spray line nozzle.

At the request of the staff the licensee has performed an analysis for the limiting location which is the feedwater nozzle, using the methodology at our command which is using ASME code Section 3. The analysis has confirmed that CUF will be below one okay through the period of extended operation. However I believe assuming the same environmental multiplier, the result with more analysis show a higher value of CUF though below one. And so the staff has requested the licensee to perform also the corresponding analysis for the two additional cases where there are geometric discontinuities or no symmetric loads and essentially the locations are the circulation outlet nozzle and the coarse spray line nozzle.

Today I believe the licensee wants to

present their methodology and make the case for the analysis they performed originally. I believe the issue so far as the SER is closed in the sense that they have committed to perform the two additional analyses as requested by the staff.

But we will hear both from the licensee and the staff about this contention and it's an important issue because it may affect other licensees that have performed calculations before using the same methodology used by Vermont Yankee.

We would like to introduce and turn over to PT Kuo.

MR. KUO: Thank you, Bonaca.

Yes, this is indeed the last issue for the Vermont Yankee license renewal application review.

It has taken a long time, longer than what we would like to, but I think at this point we believe that the applicant has done what we have asked for, and we are satisfied with what they have done.

We have supplemented our SER with our writeup. It's just I believe a week or so ago. And sent it to the committee members.

I believe that right now with the additional calculations the applicant has done we consider this issue is resolved, and the applicant will first give you the story of how it is resolved, and the staff will also give you the reason, the basis of why we think this is acceptable.

Thank you.

With that, applicant, please, take over.

MR. DREYFUSS: Good morning.

Thank you, Dr. Bonaca, Mr. Chairman, members of the committee.

My name is John Dreyfuss. I'm the director of nuclear safety assurance for Vermont Yankee.

Before we get going with the presentation I do want to make sure that we introduce our Vermont Yankee and Entergy team here.

First, I'd like to recognize Ted Sullivan, our site vice president.

MR. SULLIVAN: Good morning. I'd like to thank the committee for allowing us to be here today to continue the discussion on our license renewal application. And I'd like the team to identify themselves, and then we'll turn it back over to John.

John's our lead spokesperson.

MR. MANNAI: David Mannai, licensing manager, Vermont Yankee.

MR. RADEMACHER: Norm Rademacher, engineering director.

MR. FITZPATRICK: Jim FitzPatrick, design engineer.

MR. STEVENS: Gary Stevens, structural integrity associates, consultant to Entergy.

MR. GOODWIN: Scott Goodwin, design engineer.

MR. METELL: Mike Metell, license renewal, project manager.

MR. YOUNG: Garry Young, manager of license renewal for the Entergy fleet.

MR. COX: Alan Cox, technical manager, license renewal.

MR. LOCK: Dave Lock, I'm part of the Entergy license renewal team.

MR. DREYFUSS: All right, very good. Good morning.

Next slide, Beth, please.

For the agenda for today we will go through the environmentally assisted fatigue. And we do recognize the last time we were here we went through the rest of the SER and application and talked about a lot of different issues.

Our focus here on our presentation is as requested on the fatigue issue.

So we'll go through an overview of that, some of the timeline, how we got to this point. We'll talk about some of the bases, and go through both the evaluation that we performed where there were challenges from the staff, and confirmatory analysis.

And just from a nomenclature standpoint, I did want to mention, a number of different terms have been tossed out. What we will refer to during the course of our presentation, we had original analyses, for the license renewal we performed re-analysis. I think we referred to that in the SER; you may have seen the simplified analysis. So we've called it a re-analysis.

And then the confirmatory analysis that we did I think is also referred to variously as the updated analysis. So for us re-analysis and confirmatory and we'll step through that as we go through the presentation.

I think the key thing to talk about is that for the license renewal the confirmatory analysis that we performed for the feedwater nozzle is the calculation of record for license renewal.

Additionally we'll talk about the license condition. We do have a license condition where we will perform calculations, confirmatory calculations, for the remaining two nozzles that were the subject of the challenges, and we will perform those calculations prior to two years prior to entering into the extended period of operations.

Next slide.

From an overview standpoint we did, as far as the full scope of environmentally assisted fatigue, we did the locations that are identified in the governing NUREG 6260, and that was the focus and the basis for the calculations that we did do.

Our original piping was designed to the B31167 code so therefore we did not have the calculations. That is what drove why we had to do these calculations.

From a timeline standpoint in September we completed the re-analysis as well as all the rest of the work that we did on environmentally assisted fatigue. There was an audit by the staff of those calculations in October. And really during the course of that timeframe, from October through January of 2008, a lot of questions back and forth, and a number of different RAIs and audits that were performed questioning the approach that we had taken.

And the key challenge was how we treated stresses at the blend radius for these three particular nozzles, coarse spray, reactor recirc and feedwater.

So what we'll do during the course of the presentation is, we'll talk about what we did on that reanalysis, and provide you with the basis for that. We will also talk about what we did on the confirmatory analysis as well.

We did complete - we had requested a public meeting. And that public meeting was held on January 8th, where we defined what approach we took with the reanalysis method. At that meeting we also said that we were working on a confirmatory analysis for the feedwater nozzle.

We did complete that analysis on the nozzle and submitted that on February 14th - I'm sorry, January 30th, Ray. And NRC, Dr. Chang, did an audit of that calculation on Valentine's Day of 2008.

We also submitted an amendment that provided some chemistry data. That was one of the key questions on how we treated the chemistry effects, and how it may have influenced environmentally assisted fatigue.

So as far as basis for the evaluation, we are consistent in our approach, consistent with the Gall report. We did evaluate the specified locations as I mentioned in the NUREG 6260, and the Fen methodology that we used was appropriate and was driven by the two cited NUREGs there for the different materials, carbon steel and stainless.

Additionally we did use our as-built drawings to do our analyses. We used the design.

MEMBER ABDEL-KHALIK: How different are the as-built drawings from the design drawings?

MR. FITZPATRICK: There is additional thickness for - this is Jim FitzPatrick - the shell has additional thickness in it from the design for rolling, like a quarter inch, and the nozzles have a little additional thickness from the original design provided on the fabrication drawings.

MEMBER ABDEL-KHALIK: And when were those as-built dimensions acquired?

MR. FITZPATRICK: They are on the GE drawings of the design before the plant started up.

MEMBER ABDEL-KHALIK: Thank you.

MR. DREYFUSS: We did use design transients versus the actual transients, so did not take credit for any - we used the conservatisms associated with design transients.

We'll talk a little bit more about cycle projections, but we did project cycles for 60 years. We'll talk about some conservatisms that we have inherent in those projections as well.

We also assumed -

CHAIRMAN SHACK: So when you say design versus accident transient severity, it means you are using the stresses from the design transient, not the numbers of the design transient?

(Simultaneous speakers)

MR. DREYFUSS: And again we did assume full uprate conditions for the 60-year period. We did do the uprate in 2006.

MEMBER ARMIJO: From day zero uprated conditions, and put those into all of these analyses?

MR. DREYFUSS: That's correct. Assume

from 1972 up to this point and through the 60-year period.

Now we are going to talk about the specifics of the evaluation itself, and Jim do you want to talk on this a bit.

MR. FITZPATRICK: We used existing design analysis for the RPB shell, the lower head, the recirculant nozzles, and by the FEM to those existing analysis, and for the fatigue analysis MB 3200 rules, for three nozzles that entire original design fatigue usage, we analyzed for new models, new analysis, for the feedwater recirc outlet nozzles and the coarse spray nozzles.

MEMBER ARMIJO: Was the feedwater inlet temperature changed as a result of the uprate?

MR. FITZPATRICK: 372 to 392.

MEMBER ARMIJO: Now is that change in the conservative direction as far as this analysis is concerned?

MR. FITZPATRICK: It increases the stress range from your normal operating down to your injection. Delta T goes from, instead of 372 to 100, it goes from 392 or 394 to 100. It's a small increase in range.

MEMBER ARMIJO: Okay, thank you.

MR. FITZPATRICK: And then for the piping we performed new ASME class I fatigue analysis for the recirc RHR.

On the reanalysis of the three nozzles, we used 60-year cycles projected based on design transient severity and the cycle. So basically reviewed our design spec, and updated BWR for thermal cycle definitions.

We had new answers, find out what models are developed for these three nozzles using the as-built drawings and the material specs for each one of these nozzles.

Heat transfer coefficients were based on the design report and design specifications.

A thermal stress response in the reanalysis was developed from a step change in the temperature. And Green's function was developed from that.

Using the Green's function we developed thermal transients, stresses, for each set of the design transients for each nozzle.

And we calculated component stress differences. This is where the difference between -

we'll explain a little further on, but this is where -

CHAIRMAN SHACK: Let me just come back to your Green's function. So you got your Green's function essentially from a finite element analysis -

MR. FITZPATRICK: Yes.

CHAIRMAN SHACK: - with a step transient.

MR. FITZPATRICK: Yes, sir. And you pull component stresses from there versus - it calculates stress intensity. And that has led to some confusion before.

Taking those, the thermal stresses, the pressure stress intensities were directly from the answers found with the models, and they were factored to account for the actual pressure during the transients, the unit load case and then factored up for that.

Adjusting intensities to detached piping loads were conservatively calculated and added to the other stress intensities for each transient and each temperature.

The maximum stress differences from the temperature transients were combined directly with the stress intensities from the pressure stresses, and the detached piping loads.

And the ASME MB 3200 fatigue calculations performed on the collective thermal transient stress systems.

And that gets rid of the ASME CUI. Then we used a bounding fatigue life correction factor for all the transients, one bounding number applied to that CUF for the entire 60-year operating period.

And then the environmental CUF is that bounding factor times the CUF.

We had a list of -

CHAIRMAN SHACK: One other - every time I read the analysis it says, axi-symmetric ANSYS model. This is a nozzle on a cylindrical shell. Why is it axi-symmetric?

MR. STEVENS: It's a simplification to - obviously when you model a nozzle axi-symmetric you treat, the vessel then becomes a sphere. So we also had to apply a correction factor to account for the ovalization of two intersecting cylinders.

And that's just a traditional way of industry way of modeling these nozzles.

MR. FITZPATRICK: Did that answer your question?

Some of the conservatisms in the analyses, the major ones -

MEMBER ARMIJO: Just before you go on, the bounding fatigue life correction factor, you say you calculated from water chemistry conditions expected to occur over the 60-year operating period. But you have had major changes with the water chemistry with hydrogen implemented many years after. So which is the water chemistry you used? Did you use the appropriate water chemistry for the normal water chemistry period, and a different water chemistry correction? Or the hydrogen water chemistry period?

MR. FITZPATRICK: Did both, and Gary can give you a detail on that.

MR. STEVENS: We actually broke the operating history up into three parts. The prior to hydrogen water chemistry, or normal water chemistry, where the factors, at least for the carbon and low alloy would be much higher and the oxygen content was higher.

Then we had the operation that was post hydrogen water chemistry implementation, with the historical duty if you will or availability of the system.

And then in the future and what that's projected to be. And that was based on water chemistry guidelines that the plants are following.

CHAIRMAN SHACK: And you used bounding strain rates for all these transients? Or you actually tried to estimate strain rates?

MR. STEVENS: We used bounding strain rates for everything.

MR. DREYFUSS: And we will talk a little bit more about chemistry during the course of the presentation.

MR. FITZPATRICK: Some of the major conservatisms in the nozzle reanalysis. The number of transient cycles using analysis was greater than the expected number of cycles for 60 years based on our plant experience. For example, heat up and cool down, there were 300 cycles - heat up cool down for the feedwater nozzle includes heat up and then a turbine roll. It's basically the major transient. We used 300 cycles of that. To date we've had 95 over 36 years of operation, and the original design was 200; we don't even expect to hit that number, based on the past history of 20 years of operation.

But the plant had more transients in the beginning than they do in later life.

The transient severity is a conservatism versus using actual transients. We used the bounding values, the pressure and temperature of the EPU for the entire life, and the bounding Fen multiplier. We used values, the input stat, the temperature strain rate, the sulfur content were chosen to maximize that. And that multiplier was basically applied to all transient stresses, and that was the reanalysis method that we used.

MR. DREYFUSS: We talked about the chemistry itself. Bottom line is we chose our chemistry factors conservatively, and chemistry effects have been conservatively factored into the analysis that we did.

We did use the Fen factors from the cited NUREGs. Additionally we selected the various parameters that you see here in such a way as to maximize the effects and maximize the contribution that they had in terms of their effect on the environmental factors.

So strain rates, temperatures, dissolved oxygen, were all factored in that way.

CHAIRMAN SHACK: Of course there is no

conservatism in that sulfur number since your sulfur probably is well over .015. In the materials you actually have in the plant.

MR. DREYFUSS: Correct.

MR. STEVENS: Plus that particular parameter tends to have less effect on the relations than some of these, oxygen and temperature and strain rate for example.

MEMBER ABDEL-KHALIK: Well, typically, how long would these oxygen excursions last?

MR. FITZPATRICK: A couple of days when there's the heating up, and you do a cycle flush, and then you start heating the reactor up, conduits come online. It takes awhile to get to the steady state on the chemistry.

MR. DREYFUSS: The startup might be over an 18-hour period, but getting it back to a stable condition will sometime take a day or two.

MEMBER ABDEL-KHALIK: So the different between the value that you used and the analysis, which is the mean plus one standard deviation, the difference between that value and the nominal value for dissolved oxygen, what would that be in percentage?

MR. FITZPATRICK: It's a little different. That number could be significantly higher, but there's no transient occurring at that time. So looking at 60 years we tried to do a bounding number, a representative number for all the transients expected to occur over 60 years.

MR. CHANG: If I may interject something. The staff did a focused review of what they did, especially in the oxygen content and excursion.

Now this is a BWR, not a PWR. The PWR, the maximum transients for the most critical components is during the heat up and cool down. The PWI especially the feedwater nozzle - now excursion of the oxygen content occurred during the heat up, but at that time there are no significant transients. So even excursion rate is high, applied to - if you apply to zero it's still zero. I don't mean zero; I mean small number.

MEMBER ARMIJO: So these excursions, these oxygen excursions, really had a very small contribution to the number that you used for the Fen?

MR. DREYFUSS: Right, it did not significantly impact it.

So the summary here is that the

cumulative usage factors at Vermont Yankee under all analyses that we did perform do remain below one for the full 60 years of extended operation with margin.

I'll talk a little bit about the audit that NRC performed of the calculations. And the key challenges really were when we had done the analysis, we did the feedwater coarse spray and reactive recirc nozzle corners. The challenges were at the nozzle corners, the blend radius as it's referred to as well. And the methodology by which we treated the stresses was really the key factor as Jim had talked about as well. So we used component stresses, stress difference versus the maximum stress intensities. And what it comes down to is the treatment of sheer stress and are you neglecting sheer stress using this methodology.

That was the challenge. So we did submit this amendment 33, based on or in response to an RAI. And we documented the evaluation that we had performed and the methodology by which we had treated the stresses versus the component stress difference.

And we did essentially a sensitivity calc that resulted in a change, a maximum difference between the reanalysis that we had performed and the sensitivity that resulted in a very small maximum change, a .003 change which I think would have been complete at that point. But we really only addressed one element of the challenge.

And Gary, if you would explain a little bit about that.

MR. STEVENS: Yes, I think what we really addressed in that response was the effect of sheer stress.

Another part of the challenge was on this, it's been coined in several different ways, uni-axial stress, one-D virtual stress. And I think what I'd prefer to do is, we have a slide coming up where we show the analyses we did side by side, and I can get into a little more detail on that one.

But for the purposes of this slide, I think we generally agree that we might have satisfied the sheer stress issue, but we didn't satisfy the uni-axial or one-D virtual stress issue. And we'll talk about that in a few more slides.

MR. DREYFUSS: And Jim, if you could step us through the approach that we did here on the confirmatory calculation.

MR. FITZPATRICK: We did a confirmatory

calculation on one nozzle, a feedwater nozzle. It's the controlling nozzle, because it is the most severe in design transients; had the highest fatigue uses of the three nozzles in question.

And we tried to put this, in simple terms, basically it's cold return water and is the hot vessel. That's why it is the more severe - the most limiting nozzle.

A number of design transients at two to three times the number of transients for the other nozzles. All the injections occur at that nozzle, versus the other ones feeling just the environment in the vessel.

And industry experience has shown that the fatigue usage is typically higher at the fatigue - at the feedwater nozzle than any other nozzles.

We used the same ANSYS finite element model, the same transients, the same cycles, and the same water chemistry that is the previous nozzle reanalysis.

And the confirmatory analysis, you combine six stress components for NB-32, 16.2. The sheer stresses are included for each stress.

And as the fatigue analysis was done for

NB-32 2.4 for all the stress pairs, and this is the same methodology used in the reanalysis.

CHAIRMAN SHACK: What is the difference between the confirmatory calculation and the reanalysis?

MR. DREYFUSS: We are going to show that on a slide. I make that very clear.

CHAIRMAN SHACK: Not the difference in the results. What's the difference in assumptions?

MR. STEVENS: Should we go to that slide now? So this slide has the two analyses in parallel, the reanalysis, and the confirmatory calculation.

And what's in bold we'll talk about is going to answer your question on what the differences are.

And I don't mean to simplify this calculation, and this analysis; it's done in six steps. We've simplified into six boxes, which in no way indicates that there are six simple steps to this. It's an ASME code analysis, and there is a lot of rigorous detail built into this.

So let's start at the left, and we'll kind of go through these both in parallel. Because you'll see a lot of the boxes are identical.

On the left we have 60-year cycles in design transients. That was the same and identical for both analyses. We assumed the same transients and the same quantity; we didn't differ on those.

We built an ANSYS finite element model. It was the same for both analyses. There was no different in model at all.

The model how we used it was, and the stresses we obtained, is where it was different, and that's the next one. So for in both analyses we'll take the simple part first, pressure stresses and piping stresses - pressure stresses were determined from that finite element model, pressure stress intensity, and piping stresses were done by hand. That was identical for both.

Now let's go to the first box, and here's where we have the first difference. In the first analysis rather than run all the transients, and we have approximately 20 transients in the feedwater nozzle - there's many and they are complicated - rather than run all of those individually through the finite element model, we used a Green's function to generate the stress history for those transients.

That's - the Green's function is a well

known technique in most all college mathematical textbooks. I don't think there is any controversy in how the Green's function generates stresses. But we'll talk about this uni-axial or one-D stress in a minute, and that's really where the contention lies there.

But in the first case, the reanalysis, we used the Green's function to generate stress histories for all those transients. That takes a significantly less effort than running all those transients through the finite element model.

CHAIRMAN SHACK: But this is purely an elastic problem, right?

MR. STEVENS: That's correct, so Green's functions would be appropriate for that. Everything is linear.

Now in the second case, the confirmatory calculation, we ran everything, all the transients individually through the ANSYS finite element model. So up to now the only difference is, we used a Green's function in the first case to generate stress histories; in the second case the ANSYS finite element model.

To your point the two should be

identical, because everything is linear.

So how did we combine - moving on to the fourth box - how did we combine and determine maximum stress intensities? Here is where we get into some esoteric differences between the two.

I'll take the easy one first, which is the lower one, the confirmatory calculation. We basically take for all those transients, we get six stress components out of the finite element program, X, Y, Z and three shears. And we combine those for NB 32 16.2 of the code, which for every peak and valley you take differences, in those six stress components, and you rotate those into principal stress differences, and it's stress intensity. And you use that history, resultant history, to calculate fatigue usage.

What did we do with the Green's function? We'll move up to the reanalysis. The Green's function, what we did there is, the Green's function itself, the stress history we got out of the finite element program, we could have had six Green's functions to use to generate six stress histories, six component stress histories for all the transients.

What we took out of the finite element program was basically the maximum stress difference, which is essentially equal to the stress intensity from the finite element program.

So what we got from the Green's function was a stress intensity history, and we used that to integrate and come up with a stress intensity history for all of the transients. So I think you can see that the simplification here that was made, and there are several, we are obviously by using the maximum stress component difference we are ignoring sheer stresses.

And in some of the responses to the RAIs, and John mentioned on the one slide we showed the sheer stresses were negligible.

But the other issue that we didn't address in those RAIs is taking a single stress intensity history and using that through a Green's function to generate a stress intensity history for all these transients.

Is that identical or proximate or close to taking all the six stress component histories and doing differences and rotations into a stress intensity difference? I think there is where the difference and the contention really lay was that approximation.

Both of these analyses, the intent is to do an ASME code fatigue calculation. There was never any intent not to do so.

The difference in that step I think is really key to our differences. And obviously doing a confirmatory calculation was intended to resolve that issue, proof that how close these were.

So after that step then we have a stress intensity history that was computed differently in each of the techniques. But given that stress intensity history, the fatigue usage analysis was performed identically between the two.

There is a type on the slide here. It's not NB 32 24, it's 32 22.4.

MR. RADEMACHER: So that is 32 22.24?

MR. STEVENS: Correct. So that step is identical between the two. And then the last step is - we get a fatigue usage out of that fifth box that we then apply environmental factors to.

In the reanalysis, the first one we did, the maximum Fen was applied to the total usage, to come up with the environmentally assisted fatigue number.

In the confirmatory calculation a maximum Fen was computed for each load there, where the only thing that was taken into account was the temperature. We took the maximum temperature of each load, put the strain rate and the sulfur and all the other primaries were the same. And good or bad the intention of that difference there was to demonstrate yet another conservatism built into the analysis.

So the only thing different in the last step, which is the environmental fatigue evaluation, was one Fen applied to total usage in the reanalysis; multiple bounding Fens applied to each load pair in the confirmatory calculation.

MEMBER ARMIJO: So the more conservative treatment was in the reanalysis?

MR. STEVENS: For that step.

MEMBER ABDEL-KHALIK: How much do the material properties change over the temperature range let's say for the feedwater?

MR. STEVENS: I can't give you a specific answer, but generally speaking there could be 10 to 15 percent variation I the material properties over the range of temperatures we are looking at.

MEMBER ABDEL-KHALIK: And how is that accounted for in the analysis?

MR. STEVENS: In the reananalysis we picked bounding temperature properties. Because of the Green's function use, everything - you do one run and everything is constant. So we tend to take the bounding material properties and heat transfer coefficients.

In the confirmatory calculation the material properties are varied with temperature input to the finite element program as well as heat transfer coefficients.

And you are really touching on one key element here, if you take these - we have identified really just three bold spots where these analyses are different. We identified on an engineering level 20 differences in these two analyses, things like you just mentioned, material properties; they were treated differently. Heat transfer coefficients were treated differently. Twenty differences between the reanalysis and the confirmatory calculation really that were levels of conservatisms built in to the analysis, approximations using a simplified approach versus a very detailed approach.

So we did not go through exhaustively a parametric study to understand which of those 20 items caused the differences between the two. We were satisfied at the end that the final result we got was the same, usage factor less than one with margin.

MR. DREYFUSS: Do you want to move on to the results?

MR. CHANG: Before moving on, could I put in a couple of comments?

I think Gary have summarized what you call the reanalysis and what you call the confirmatory analysis very nicely.

But I'd like to bring out a couple of key points that can facilitate going right through the heart of the issue.

Actually applicant submitted two reanalyses. One was submitted by amendment 31 which is dated 9/17. The second refined analysis was submitted December 11^{th}; that was submitted by amendment 33.

So those two I call them just reanalysis. And then there is a final confirmatory - you call final confirmatory analysis submitted by amendment 34 on January 30, `08.

Now in our final SER, submitted to the ACIS and it was issues, we call that analysis as analysis of record for the feedwater nozzles. Why? That's the point I'd like to point out. Missing this phase, this is the opportunity, you may keep in mind, reanalysis, analysis of record, which is not the case. The - now let's call that analysis of record. The analysis of record took all the unknowns out of the place. You use six components, stress, including sheer stress and nominal stress. Only thing is you approximate the header effects by a spherical header. That as Gary said is a very standard industrial approach. We buy that.

The difference comes that the reanalysis did not analyze every transient. From the base transient case, and finite element results, from that base case you project it to the other transient stresses by the Green's function.

I don't dispute the Green's function methodology at all; I love it. The only way is, how do you apply it? Now you apply it by six components, or you apply it by one-D virtual stress.

The reanalysis still have the one-D

virtual stress there. But the analysis of record do not have that.

So let's for the time being call the analysis of record close to the reality. The outcome, you don't see it at the amendment 34. Because amendment 34 seems to indicate the analysis of record always give you a lower answer. That means the reference analysis is conservative.

But that is deceiving, because if you use the same Fen as you used in the refined analysis, the CUF will be higher. As I report it, as the staff report it in the final SER, that number, the CUF, will be .893. It's not .353 anymore.

So in other words the analysis of record gives you higher CUF for everything the same condition.

In other words the refined analysis can be conservative, can be not conservative; can be conservative by a factor of two; and also can underpredict by a factor of two.

For that reason we don't call that the refined analysis or analysis of record. But for Vermont Yankee the feedwater nozzle, the final analysis, additional analysis, or whatever you call it, still give you at least 10 percent margin to the code CUF limits.

For that reason I feel comfortable. Now as long as you make this as the analysis of record. For the future if you want to adjust anything you base it on that. You don't back to the refined analysis. On the same basis if this can produce results like this, the same or similar results can also be produced. I'm not sure, because I didn't do that analysis on the other two nozzles.

For that reason we asked them to perform similar analysis for the other two nozzles. When all this is completed, we have three analyses of record. Those are fully justified.

VICE CHAIRMAN BONACA: What I would like to point out, however, is that this calculation results seems to be consistent with the one that was in the SER. So we would like to understand it better.

In the SER you asked the licensee to use the same maximum Fen.

MR. KUO: Right, what we consider that is acceptable is what the applicant calls confirmatory analysis.

VICE CHAIRMAN BONACA: Yes, but here in the confirmatory analysis I see the result being 0.35, and you are quoting .893.

MR. CHANG: Eight nine three, we have both numbers reported in the SER, so it's on record that the analysis of record, using the maximum Fen, you will get .893. But you use 24 different values of Fen which is appropriate, you will get .353.

In other words, the .353 is not wrong; it's just compare the earlier analysis and the newer analysis. The earlier analysis may not be conservative. It depends on the final analysis which we know is right and conservative.

CHAIRMAN SHACK: What you are arguing is that his stress analysis could be nonconservative, and he covers that up by using a conservative Fen, but clearly his overall calculation is conservative but he's piling it up in different ways, and I guess the question is, is that always going to be the case? It's certainly true in these two situations.

MR. CHANG: Normally staff do not second guess what the future outcome will be. But since this feedwater nozzle, the CUF, is five to 10 times higher as compared to the others, I would imagine the other two nozzles when you complete your analysis give us a good foundation to work for the future. This number will also be good.

MEMBER ARMIJO: I'm a little confused. The mechanical analysis I think, the confirmatory calculations were done by the methods the staff was comfortable with and were done with a lot of conservatism as pointed out in some of these charts.

In addition they applied a more realistic Fen for different periods as opposed to the original reanalysis approach. But still conservative.

So I don't know, and there's a big difference in CUF, right, .35 versus .89, that's a very big difference. So what does the staff consider to be the official number for CUF for this nozzle?

MR. CHANG: .353.

MEMBER ARMIJO: Okay.

VICE CHAIRMAN BONACA: Because in the SER you state very clearly that any request of the licensee to use a maximum Fen, and you got the value of .89, okay, still using the confirmatory calculation now it ends out to .89, and you are saying because it is higher than what you calculated with the reanalysis which was .64, then the analysis of record has to be the one with the higher value.

So here we are talking about apples and oranges. I mean I'm trying to understand what is the confirmatory calculation result, and what is the basis for forcing them to use the highest Fen? I mean that's probably the best question.

MR. CHANG: As many people call the fatigue analysis, it's a black box. You can turn out different results depending on the level of sophistication that goes in there.

The first step we are trying to establish is, is the Green's function methodology or the confirmatory analysis methodology, which is correct.

We say the confirmatory analysis methodology is correct. That's the purpose of bringing the .893 up.

VICE CHAIRMAN BONACA: But you told me that 0.35 in the confirmatory analysis calculation is conservative; that's what you said.

MR. CHANG: They are realistic. Realistically speaking, the refined analysis do not have to use Fen equal to 11 to all the transient pairs. If you make every assumption the same, confirmatory analysis will get you lower results.

MR. KUO: Just like you said, Dr. Bonaca, comparing this two analyses here is comparing apples and oranges, because the numbers involved are different in terms of Fen.

For the reanalysis that they used, okay, they used a bounding Fen value for all transient pairs. But for the confirmatory analysis as they called it they used Fen, maximum Fen for each transient pair.

VICE CHAIRMAN BONACA: that is what I understood. And you said you have to assume the same Fen for both methodology if you want to compare results.

MR. KUO: If they were to use the same bounding Fen for all transient pairs, using the methodology in the confirmatory analysis, the number would have been .893.

VICE CHAIRMAN BONACA: Okay, that's why you are talking about -

MR. CHANG: Dr. Bonaca, Robert Schu, who used to be on my staff and is fairly involved on this topic, he may supplement some of the points.

VICE CHAIRMAN BONACA: No, I understand now. But go ahead.

MR. SCHU: May I say something? Because basically when you are doing the fatigue analysis you've got to calculate the stress. And right now the stress implemented by the applicant is not correct. Compare - it's not adequate, because everybody believe the ANSYS result is adequate. So we asked the applicant to compare their methodology with the ANSYS analysis. The result, there is no way they can match. So from that analysis record point of view, their Green's function, any time they do a Green's function analysis, they've got to redo the traditional ANSYS analysis.

And actually the traditional ANSYS analysis will create the correct results and that's NRC accept.

MR. CHANG: The traditional ANSYS analysis will create reasonable results. That result could be higher; it could be lower. But that's reasonable. That's correct. That's why we think our - that's will be our future basis.

We want something to be correct.

MR. DREYFUSS: Garyk if we could summary?

MR. STEVENS: Okay, let's forget abou8t the sixth box here, which is the environmental fatigue, and let's look at the fifth box, which is, we've got the stress history. We calculated fatigue. And let's write some numbers down and put everything in perspective.

CHAIRMAN SHACK: That is the CUF in error if we just quite at the fifth box.

MR. STEVENS: We will compare apples to apples here, which is CUF from each analysis prior to an application of environmental factors.

Okay, the top box, the CUF for 60 years from the reanalysis was .064.

The bottom analysis, fifth box, the CUF for 60 years was .089. The difference between .025.

If we applied the same environmental factor to both fo those numbers, the difference in the magnitude would be identical to comparing those two numbers. So if I decided the environmental factor is 11, and I applied them to both, the ratio of the two would be the same.

So comparing apples to apples here, the confirmatory calculation, .089 versus the reanalysis of .064, as I mentioned before there were 20 some odd differences built into these two calculations, any one of which could have contributed to that difference.

The use of a single stress intensity history could be one. The material properties varying with temperature could be one. The heat transfer coefficients varying. Any of them. We did not do exhaustive analysis to determine which one contributed how much.

So I think what the staff is saying is that that increase is what has led them to the license condition for the other two nozzles.

MR. CHANG: You are correct.

MR. DREYFUSS: This is what took from September or so up to this point, going through this and trying to address staff questions on it.

It became clear to us that a simpler approach is to go with the confirmatory approach. That is why we did that for the feedwater nozzle, and we do have that license permission.

MR. CHANG: when all the three nozzles were done, the three confirmatory analyses would become three analyses of record; that's important.

MR. MANNAI: This is Dave Mannai, licensing manager. I'd like to make one point, because I did sense a little bit of concern on the part of the staff, the ACRS committee. The bottom line is, we agreed with the NRC in their request to make the confirmatory analysis the analysis of record.

When we had performed the calculation and then subsequently the NRC staff had ordered that calculation, they looked at our methodology, and they did not disagree with the fact that for the confirmatory analysis that the maximum Fen factors had to be chosen for each transient, but that was a more realistic use of that calculation that was wholly appropriate as Dr. Chang said a month ago.

And so if you stop in the middle of it you'd say oh there is this big difference. But as the analysts went through and our own folks reviewed that and then subsequently the NRC staff reviewed it, there were no concerns with the use of that calculation or those assumptions that were used.

MEMBER ARMIJO: Okay, so there is no disagreement with the staff on the use of bounding Fens for each transient pair as the right way to go; correct?

MR. MANNAI: Right.

MR. KUO: It is more realistic. The

reason that we want to make this so-called confirmatory analysis as the analysis of record is to prevent future readers getting the wrong impression. The original reanalysis is still the right reanalysis that we accept.

MR. CHANG: If you only read this analysis result once, you want to read the right one. You can skip all the intermediate steps.

MR. DREYFUSS: Okay, next slide.

These are the results, we've talked about them. And the next slide.

I'll speak a little bit about the license condition. As discussed, the confirmatory analysis for the feedwater nozzle is complete. It is the calc of record.

The reanalyses performed for coarse spray and reactor recirc outlet you can see the CUFs adjusted for environmental factors here. The .17 and .08, we fully anticipate that as we perform the confirmatory calculations, that we will again be below one with plenty of margin, and that in fact the feedwater nozzle is the controlling nozzle for us.

The license condition itself is, we will perform the confirmatory analyses for coarse spray and recirc outlet no later than two years prior to going into the extended period of operation.

MEMBER ARMIJO: If you are already tooled up for this analysis work, why don't you just do it?

MR. DREYFUSS: There is some additional work to do, there's resources, there's modeling work that needs to be done. We will be getting to work on that. We just don't have those analyses complete yet. Our intention is that we will be working on these during the course of this year, and getting that work complete.

VICE CHAIRMAN BONACA: Thank you for the presentation. It was clear, and we begin to understand what's happening here. And now we go to the staff presentation, right?

MR. ROWLEY: Good morning. My name is Jonathan Rowley, and with me I have Dr. Kenneth Chang. And we will discuss the environmental fatigue issue as it pertains to the Vermont Yankee safety evaluation report.

Next slide. I'd like to give you a quick recap of this discussion from the February 7th, HRS meeting. We talked about the resolution of this concern, and the included license renewal, the license condition that we have applied to Vermont Yankee.

Next slide.

As you can recall Vermont Yankee revised their application to use the fatigue model for their management of fatigue for the extended period of operation. The corrective action element of that program allows them to do a reanalysis of components. They submitted those reanalyses to the NRC that included incorporated environmental fatigue on September 17th, 2007.

We performed an audit of those reanalyses on October 9th and 10th. We asked six audit questions during that audit. One was not answered to our satisfaction, so we made that an RAI; we sent that on November 27th, 2007.

The response to that RAI came back on December 11, 2007.

We had some discussions about this RAI. There were some differences in nomenclature and other things that we couldn't quite work out, so we decided to have a face-to-face meeting on January 8th, which was a public meeting on January 8th, 2008, at that time they agreed to submit a confirmatory analysis of the feedwater nozzle. Next slide.

That analysis was to include benchmarking for the Vermont Yankee's feedwater nozzle using axi-symmetric on that element model, taking full care of all stress components of the nozzle using ANSYS code for all defined transients; demonstrated that Vermont Yankee specific benchmarking calculations bound the coarse spray and the recirculation outlet nozzles, calculated fatigue usage factors were done by ASME code Section 3, and they can compare the results to the previous calculations to determine if they were conservative or not. Next slide.

On January 30th Vermont Yankee submitted those what we called - a terminology change - updated analysis, which is one and the same with the confirmatory analysis. They proved to us that they used the same parameters, same data, methodology, as agreed upon.

And the last slide, what was stated during the January 8th meeting; determined that the CUFs were the safe ends and then rated lower than the previous analysis.

Next slide please. Supplemental information was submitted to us on February 5th to demonstrate that the updated feedwater analysis bounds the recirculation outlet nozzle, and it described how the water chemistry effects were accounted into this analysis.

Next slide. We performed an audit on February 14th, Valentine's Day, and we discussed the things listed here. And I would like Ken Chang to talk about what we did at that audit.

MR. CHANG: I will not follow these slides. Instead I will go through the process of how we performed the audit.

The audit, the main purpose to address the concerns expressed during the previous ACIS meeting. So really it's the chemistry, effect of chemistry on this EF analysis.

So we spent a good time of the day reviewing the absorbed oxygen content, the strain rate, the temperature, the surface content, those parameters that they used in the confirmatory analysis or the analysis of record.

Those parameters were properly used, like the dissolved oxygen is average plus one standard deviation. And then we asked about whether any excursion was there, the excursion happened during the heat up. During the heat up process we found that the feedwater nozzle don't have any significant transients, although it doesn't bound the oxygen level during the heat up, so that doesn't really matter.

And we also looking at the strain rate, a low strain rate to bound the value, to bound the Fen value, was used all along.

And the temperatures, we assumed using 550 degree Fahrenheit for the nozzle, which is also bounding.

For the surface content, for stainless steel, surface content is not one of the parameters evaluated by NUREG CR 5704. But for the carbon steel, .015 percent was used to have the maximum impact on the Fen.

We also look at how they performed this confirmatory analysis. The confirmatory analysis and the reanalysis use the same model, the axis-symmetric finite element model, for which the branch site is exact. You find the axis of symmetry. You do a revolution around it. But on the header pipe, on the header side, you can only simulate with either the flat plate or with a sphere.

Normally people do simulate the header effects by using a spherical header. The right way to do is to use two times the actual radius for the sphere. That way you simulate to accurately predict the pressure stress.

For Vermont Yankee there was a model using 1.5 radius already done, so I don't dispute that, since they adjust the pressure stress by another factor of 1.33, four thirds. Now four thirds times three halves, that's a factor of two. That is a typical number being used by the ASME stress analysis simulating the 3-D effects.

We also look into what Fen value we used. That has been already discussed in quite detail. I really fully endorse them of using 24 training pairs to come up the total CUF, and 24 Fens were calculated, one for each training pair. That is the most complete analysis I've seen so far. I hope we can make this as analysis of the future, as a general case.

Now, the - another question was asked during the early meeting was how was film coefficient calculated? The film coefficient was calculated correctly even including the gap between the thermal sleeve and the nozzle wall. They estimated how does the gap open or close, and calculated some film coefficient to simulate inside of thermal sleeve, between the thermal sleeve and the nozzle wall, and after the nozzle wall. So that analysis was quite accurate, and even by today's standards it's still very good.

Other transients: the two analyses use the same transients; otherwise you cannot compare. Transients got to be the same. Cycle got to be the same. Same training curves. Same number of cycles was used in the refined analysis and in the confirmatory analysis.

External piping loads, here is a little deviation from the traditional MD 3200 analysis as compared to this. Although Vermont Yankee did not apply the external piping loads in a 3-D way, but they calculated a stress intensity based on the external load.

And that external load was added, that stress intensity was added, to the stress intensity calculated for the thermal transients. After that stress intensity was calculated add on top, that is known to be conservative.

K sub e, ASME code requires elastoplastic cycling penalty factor. In old analysis normally people have K sub e equal to one. We look into it, and for the feedwater nozzle, K sub e the worst combination K sub e equals to 1.115. So in other words this 11.5 percent penalty on that underlying stress before you go into the -- allow the cycle to stress to the allowable cycle curve. That is also appropriate.

Young's modulus, ASME curve, the fatigue curve, is based on certain Young's modulus. When you are performing analysis you have to adjust your Young's modulus to the ASME code value. That was done also properly.

Six stress components, although it's not a true 3-D analysis, but six components was used. For the thermal transients, those components, in particular the unit stress giving small or big is included in their confirmatory analysis. That is, to us that's acceptable.

Seismic loading, seismic is one of the transients. Seismic, you cannot put on the 3-D analysis and put in six components, because you don't even know what it is. However, the seismic loads are small compared to similar transient loads. And seismic loads, when seismic load occurs, the strain rate is high, Fen is low. So by not considering the seismic load in the combination, produce conservative results.

Cycles: the two analyses use the same cycles, the same transient cycles. That is appropriate.

So based on these descriptions we felt through deeper review and through the cooperation of the applicant, by bringing two suitcases of material into NEI, downtown office, we reviewed there; we are very satisfied.

If you can make this as analysis of record for the feedwater nozzle, we say, we have no further questions.

On the same basis there are two other nozzles, could result in a similar way. So we say, if you perform this kind of confirmatory analysis as described above, then you heard it twice already. You heard it from the applicant; you heard from me. If you do that kind of analysis for the two additional nozzles, our confidence level also goes up for those two nozzles. So the whole issue will be resolved.

Now I really want to thank the applicant for performing this analysis, because this, let me remind you, yesterday we talk about whether on the nozzle, they are one location or two locations or three locations which you need to study.

This nozzle, the plan radius is not at the safe end. Yesterday you hear about safe end. You've got to evaluate your pipe to the nozzle well, you've got to evaluate the safe end. You've got to judge whether you have similar sleeve or not. You've got to evaluate the plan radius.

It happens to be for this nozzle the plan radius is the highest to CUF location. Did you see that yesterday? I don't. That's why we insist on performing similar analyses for similar kind of conditions and terrains.

That concludes my presentation.

VICE CHAIRMAN BONACA: Could you go to page nine?

MR. CHANG: Page nine?

VICE CHAIRMAN BONACA: Here you are talking about previous analysis. Is this the reanalysis?

MR. CHANG: Previous analysis means the reanalysis. The September 19 and December 11.

VICE CHAIRMAN BONACA: Okay. We got an explanation of what we meant by reanalysis and confirmatory analysis. So the October analysis now is the confirmatory analysis.

MR. CHANG: One and the same.

VICE CHAIRMAN BONACA: That's what I thought.

MR. CHANG: Updated analysis, the confirmatory analysis, and the analysis of record, those three are equal right now.

MR. SHUN: I am sorry, Ken, why do you say these three are equal? I thought they are different. Reanalysis is reanalysis; normally reanalysis is - they are not equal.

MR. CHANG: What Jonathan call is update analysis, and what applicant call as confirmatory analysis, we call them analysis of record.

MR. KUO: I would personally suggest, let's not confuse the issue. We, at least from staff's point of view, we stopped using the term, confirmatory analysis. We have the analysis of record.

MR. CHANG: I agree.

VICE CHAIRMAN BONACA: Are we disagreeing with the previous statement, that previous analysis means reanalysis?

MR. ROWLEY: No.

MR. CHANG: For the feedwater nozzle, there is only one analysis of record; that is submitted on January 30, `08.

VICE CHAIRMAN BONACA: Still it says, the confirmatory analysis which now has become the analysis of record.

MS. FRANOVICH: If I may, this is Ronnie Franovich, the reason that this has been such a strong view by the staff is that we are establishing a new licensing basis for license renewal, and so being very clear on what the licensing basis is for this issue is really important for the future regulation of the facility.

I wanted to answer one question by the gentleman, why wouldn't they do the analysis now for the other two locations. The end of the current - the period of extended operations really begins in 2012, and so two years before that would be 2010. So it won't be but for another couple of years th8at we will get that analysis in for the other two locations.

Just wanted to clarify that too.

MR. ROWLEY: All right, next slide please.

Our conclusion is that the feedwater analysis is the analysis of record, as performed in accordance with ASME code Section 3, the coarse spray and the reactor circulation nozzle analysis will be performed according to the fourth condition which is, next slide, that the licensee perform and submit to the NRC for review and approval an ASME code analysis for the reactor circulation and outlet nozzle and the coarse spray nozzle at least two years prior to the extended period of operation. This analysis shall be the analysis of record for these two analyses.

VICE CHAIRMAN BONACA: Now on the conclusion on the second bullet, did you say that the CUF was calculated in accordance with ASME code Section 3. But the analysis was also in conformance with the ASME code Section 3?

MR. ROWLEY: The entire analysis - the entire updated - well, confirmatory analysis, yes.

VICE CHAIRMAN BONACA: Yeah, the claim was made that the original analysis was also conforming to ASME code Section 3.

MR. CHANG: to be precise, that should be performed according to the ASME code without using Green's function methodology.

VICE CHAIRMAN BONACA: Yes, okay. They stated the same thing. So that is not the distinguishing attribute

CHAIRMAN SHACK: Well, just to defend the poor Green's function here for a second, poor Mr. Green, the Green's function is fine. It's how they combine the stresses after the use the Green's function that is the problem.

MEMBER BLEY: Calling that the Green's function method is not right.

(Simultaneous speakers)

CHAIRMAN SHACK: I did have a question, if I could ask Gary Stevens, this came up.

Does the location of the maximum fatigue usage change when you do the individual transients, decay Fen? You find that the actual location of maximum usage has shifted? You didn't look at that?

MR. STEVENS: We did. I'm trying to figure out the best way to answer your question without confusing the whole room.

The answer would be no, but what location we looked at we built into this going into the analysis. And there were several considerations.

First and foremost would be looking at what the original design analysis tells us about where the high usage location is. And that's an appropriate technique -

CHAIRMAN SHACK: Well, no, when we say high usage location, I mean are we talking nozzle or are we talking finite element location, et cetera.

MR. STEVENS: I'm not sure I understand that question.

CHAIRMAN SHACK: You get a different usage factor for every finite element in this whole axis-symmetric model, and I'm assuming the number you are quoting here is the highest usage factor for any given element that you are looking at.

MR. STEVENS: That's right. We based our selection process on really three things: maximum stress, which is going to give us high usage factor; we also need to look at different materials. Some of these nozzles have stainless steel safe ends and low alloy steel nozzle forgings which have different Fen factors associated with them. And we also have to look at chemistry, as in water chemistry.

An example there would be the feedwater nozzle where the incoming feedwater stream, the oxygen content is significantly different than it is in the vessel. So the environmental factor for the safe end would be drastically different than it is for the nozzle forging.

All that was built together, and that's why for each of these nozzles we take two locations, the limiting location in the safe end, and the limiting location in the nozzle forging. And that is a composite of all those factors going together, that collectively this gives us - between the two locations we've covered the maximum possible usage factor for the whole component.

If I - I would come up with a different conclusion if the chemistry was constant for all locations, the material was constant, I might pick one location in a safe end, in a PWR for example, especially where stratification loading is present, and it drives you back to the safe end.

In this situation here, with different materials and different chemistry, we chose to evaluate two locations to bound it.

MR. CHANG: Dr. Chang. If I may supplement what Gary says. You vary two locations, but when they say safe end, actually they evaluate three locations in the safe end; the pipe end, the pipe to nozzle weld; and the transition. Consider, next to that transition there is a thermal sleeve which can change temperature diffusion pattern.

So one location covers three areas which they did not advertise. I just tried to clarify.

MR. ROWLEY: So that ends our presentation unless there are more questions.

VICE CHAIRMAN BONACA: Thank you for your presentation. And are there any questions? Or further comments?

I guess not, so I'll give it back to you.

CHAIRMAN SHACK: Gentlemen, I think we can break for lunch until 1:15. And again I'd like to thank the licensee and the staff for very interesting presentations. It did help clarify an issue that was quite confusing.

(Whereupon at 12:04 p.m. the proceeding in the above-entitled matter went off the record to return on the record at 1:15 p.m.)

CHAIRMAN SHACK: We can come back into session.

Our next topic today are some selected chapters of the SER associated with the ESBWR design certification applications. And Dr. Corradini will lead us through that.

MEMBER CORRADINI: Thank you, Mr. Chairman. I'll just give a short reminder to the Members about where we are in this. So the purpose of this portion of the meeting is to review four chapters of the design certification document and the associated SERs that we have talked about in subcommittees. Those chapters of the SERs are chapters 9, 10, 13, and 16, with open items related to the ESBWR design certification. G.E. Hitachi, Nuclear Americas, GEH, which we'll keep on using that. I can't pronounce them all together, is here to start this off. Office of New Reactors, Amy Cubbage will give us an introduction to the folks from GEH, who will provide us presentations about those four chapters.

To remind everybody, we had the subcommittee meeting a while back, the week before Thanksgiving. Since then we've had already another meeting on another set of chapters and we're only focusing on these four chapters which we'll go through today, 9, 10, 13, and 16.

Other than that. I'll remind everybody that the expectation is we will write a letter from this as an interim letter, our second interim letter back to the staff and to the Commission.

Amy?

MS. CUBBAGE: Thank you very much. Amy Cubbage, lead project manager for ESBWR design certification. As Mike indicated, we were here back in November briefing these chapters to the Subcommittee. We've chosen to structure our presentations to focus on some of the key question areas that the Subcommittee had. So rather than go back through all the material that we presented, we're going to focus on some of those key topics. G.E. Hitachi will be presenting first today and then followed by the staff.

Jim Kinsey from G.E. Hitachi.

MR. KINSEY: Again, as Amy mentioned, we're here for a follow-up visit. We made a presentation on these four chapters to the Subcommittee earlier. We've captured the

Subcommittee's questions and comments and our focus on the presentation today will be around those topics and I'd like to turn it over to Peter Jordan from our Regulatory Affairs Department to start our discussion.

MR. JORDAN: Thank you, Jim. Good afternoon, Mr. Chairman, Members of the Committee. My name is Peter Jordan. I am a lead engineer with Regulatory Affairs on the ESBWR project. As Amy mentioned, we have these four chapters which are scheduled for discussion this afternoon and we do understand we have a limited schedule, so we have admonished our personnel to keep their remarks brief, particularly to allow the Committee to have any dialogue that they wish on these various chapters.

The presenters we have this afternoon are starting at my immediate right is Mr. Mike Arcaro, followed by Jack Noonan, Jerry Deaver, and Dan Williamson.

As we mentioned, these are the four chapters we intend to have discussion on. I would add at this juncture we do not have a specific presentation on Chapter 13, but we are prepared to discuss any topics that the Committee wishes to have some discussion on.

With that I'll start off with Mike Arcaro who will provide some remarks on Chapter 9, the balance of plan and auxiliary system.

Mike?

MR. ARCARO: Thank you very much. My name is Mike Arcaro. I'm a principal engineer for Balance of Plant Auxiliary Systems for ESBWR. I'll go over a brief overview of Chapter 9 and answer any questions or concerns you have. We also have some topics of interest that came up in the Subcommittee that we'll discuss.

Chapter 9, overview of auxiliary systems. It provides a description of the axillary and balance of plant systems required for ESBWR. These support systems incorporate design features that are similar to earlier vintage boiler water reactors with the main difference ESBWR uses passive cooling for the first 72 hours, so the systems that were safety related are now nonsafety related or written as systems.

Overview. Chapter 9 is broken down into different sections. Section 9-1 is for fuel storage and handling. 9-2 is the water systems. 9-3 is compressed air and gas systems. 9-4 are all the ventilation systems. And in addition to 9-4, control room, habitability is also found in Chapter 6-4 for control room habitability, interfaces with the ventilation system.

Section 9-5 is those auxiliary systems associated with fire protection. We also have a fire hazard and analysis in 9-A. Support systems for the diesels will be found Section 9-5 and also lighting and communications.

A couple of topics of interest we wanted to discuss today, the first one, hydrogen water chemistry. Hydrogen water chemistry, GEH has made the recommendation to customers that the best way to avoid cracking, IGGCS, is to operate with as much of the reactor in a reducing environment. And that's obtained through noble chemistry and hydrogen water chemistry application. Not all customers have followed GE's recommendations and we do have plants operating for extended periods of time without indications of stress corrosion cracking.

The ESBWR uses similar material and process selection as we see with those plants that are operating. ESBWR design is less susceptible through mitigating actions such as improved materials, welds, either avoiding welds, avoiding welds in high-flux areas, allowing accessibility for nondestructive testing.

The ESBWR basic design provides provisions for implementing hydrogen water chemistry. The shielding is in place. The space allocation is in place for installing the system. So right now hydrogen water chemistry is an optional design for ESBWR with recommendations that the customers do implement it.

The second issue --

MEMBER ARMIJO: For a matter of record, and I may not be up to date, but the sources I have on the industry that all ESBWRs in the United States are using hydrogen water chemistry or noble metal chemical additions or some version. All the BWRs in Europe are using some version. Mexico is using it. Taiwan is using it. And with the exception of certain plants in Japan are using hydrogen water chemistry. So the experience based on which we're getting perhaps more favorable IGS in heat performance seems to be predicated on the use of this improved water chemistry and so I'm just still a little puzzled by may be a small handful of your potential clients --

MR. JORDAN: Large clients?

MEMBER ARMIJO: Deciding well, maybe we don't want to use that. It's clearly an economic decision, but I'm just curious if the information I have is out of date or incorrect?

MR. TUCKER: This is Larry Tucker with GEH. Do we want to address this now or after the presentation?

MEMBER ARMIJO: Now. I would say if it's short, now.

MR. TUCKER: We have Tom Caine here with us today.

Tom, could you address the question, please. Identify yourself for the record.

MR. CAINE: I'm Tom Caine, Manager of Chemistry and Materials for GEH. To the question, as far as implementation, all of the plants in the U.S. are on hydrogen water chemistry. Most of them also using noble chem.

In Europe, I believe none of the German BWRs are on hydrogen water chemistry. Few, if any, of the Swedish and Finnish plants are on hydrogen water chemistry. Really, it's just the plants in Spain and Switzerland who are either doing moderate HWC or noble chem. with HWC.

MEMBER BANERJEE: Doesn't Forshmark use hydrogen water chemistry?

MR. CAINE: There may be one or two in Sweden, but across the board, most of them are normal water chemistry and have not had major issues with cracking, partly because of the material selections done at that time and because of the geometries, somewhat unique geometries of the licensee plants.

In Japan, a fair number, most of the plants are on hydrogen. I wouldn't say that they're necessarily at the right level of hydrogen because of operating dose rate issues and they are still in development activities to figure out the best way to address that long term. They've done a lot of reactor internal replacements, so it's not an urgent issue for them.

So there's a fair number that are running on normal R chemistry.

MEMBER CORRADINI: Does that help you, Sam, for the moment?

MEMBER BANERJEE: Yes.

MEMBER CORRADINI: We can return to this.

MEMBER BANERJEE: I guess your point will be why don't you --

MEMBER ARMIJO: I'm not sure it's a regulatory issue, but it's kind of like the life blood of a plant. And it's the most beneficial chemistry. It's still surprising to me that she just simply says that's the way a BWR should operate and hard wired into your DCD and into your certification. But apparently, there's no regulatory forcing function.

MEMBER CORRADINI: I think that's a proper analysis.

MEMBER ARMIJO: That's where we are.

MEMBER CORRADINI: The other part of the equation is that we're also making strides to improve the durability of the internals too so I think --

MEMBER ARMIJO: But you know, you can't solve the problem with just materials or just with water chemistry or just with careful fabrication. You've really got to do belt and suspenders so that this new generation of plants doesn't have chronic, infrequent, but painful cracking experience that we've had in the past. I think it's the combination of good water chemistry, good fabrication, and good materials is your -- is the way you'll keep these plants operating well without spending millions and millions of dollars repairing broken things.

And one solution alone, I don't believe will solve the problem.

MR. JORDAN: Okay, why don't you continue with the air systems.

MR. ARCARO: Okay, the next topic of conversation is instrument air quality and air moisture and contamination. Under Rev. 4 of the DCD we changed the configuration of the instrument air and service air systems. The original configuration had separate service air and instrument air systems and the current configuration, the design enhancement utilizes service air compressors to feed the instrument air system through air dryers. And the question was is there concerns with that.

To answer that, the service air compressors are oil-free compressors. They're not the reciprocating type compressors, but the modern oil-free compressors. The instrument air, the service air system is maintained at a cleanliness specification at 10 microns which is better than the

ISA cleanliness requirement.

The instrument air system is maintained at a 3 micron downstream of the air dryers. It's got continuous dew point monitor for moisture. The concern was also that what would happen if you operated extended period of time with the air dryer out of service? And in order to do that, the air dryers are designed for 100 percent capacity. We have two of those. So you would have to have multiple failures to get into a bypass mode where they're bypassing service air around the dryer and that's not a credible event and that wouldn't be how we would be operating the plants.

So the current configuration meets the requirements of the URD, Utility Design Manual. It's the configuration that the existing plants are going to and is an enhancement over the original, the original system design.

Let's see. The next issue --

MEMBER BLEY: I understood everything you said. As long as there's a -- you guys aren't actually operating a plant and so the way you would operate it isn't quite the issue. The people who do operate it sometimes even with that kind of configuration, for one reason or another have opened those bypasses and sometimes have gotten moisture out into the system. That was the concern. And I guess just recording that for now, unless you had something more to say.

MEMBER STEKAR: Operating experience has shown substantial problems with air dryers, regardless of the air dryer design. And instrument air systems operating for reasonably extended periods with the air dryers bypassed and that's just operating experience from a broad range of different plants, different system designs. It just happens. They're high maintenance, high failure rate complements.

MEMBER BLEY: And often people decide maybe I've got a problem with the dryer, let's just bypass it and see and then they leave it sit. And even though it doesn't sound like it happens, it does and it happens a lot. Well, enough that substantial problems have been seen and they can be tricky operational problems. That was our main point.

MR. ARCARO: I think the design mitigates that having 200 percent dryers by doing continuous moisture monitoring and by doing periodic testing, we test for contamination in the system.

MEMBER STEKAR: Every plant that I've ever looked at and done a risk assessment of has had two 100 percent air dryers and if you look at the fraction of time where both of them are out of service, it's a measurable fraction of time.

Everything you say in the design is absolutely true and it applies to essentially every operating plant that I've ever looked at.

MEMBER CORRADINI: I think the concern is there. I don't think we can do much more of that on this point. Is that a clear statement?

MEMBER BLEY: I think so for now. Maybe this will come up later in some of the other.

MEMBER CORRADINI: Keep on going.

MR. ARCARO: The third topic was control room habitability issues. I guess two separate topics of discussion. The first is the passive heat sink. Previous plants had safety-related control room ventilation systems to maintain the required temperatures in the control building, in the control room. ESBWR uses a passive heat sink. When power is available we have the recirc. air handling units that maintain the space temperatures. If AC power is lost, the nonsafety-related loads are dissipated and we use passive means to remove the remaining heat loads in the control building.

The question came up last time what have we done so far as far as modeling and analysis of the passive heat sink? We have a preliminary calculation. It was done in contained software for the high temperature applications and we used eco. sim. for low temperature. So the question was what conditions have we modeled for the control room heatup analysis?

The first condition was zero percent exceedence value. That's the design condition for the control room. That's using 117 degree dry volt temperature. We modeled that condition for the period 0 to 2 hours, 2 hours to 72 hours, and then after 72 hours. We modeled a second condition for the effective humidity on the control room heat up rate. So on that condition we used 88 degree wet volt temperature and 100 percent humidity and modeled that. We also looked at the winter heat load. The concern or question was what happens during the winter time when you're at -40 degree design condition and you have minimum heat loads in the control room? So we also looked at that.

The analysis, the initial analysis shows that we're within our limits for those three conditions. We don't exceed the 50-degree heat up which is the design constraint. The models are less than 95 degrees after the period of time in question. The limiting condition is the zero percent exceedence value. So the condition with the humidity resulted in a less limiting condition than zero percent.

During the winter time load, the control room temperature went down to around 61-62 degrees, so that's an acceptable value there.

MEMBER CORRADINI: If I might just interrupt so I make sure, now this is -- because when we were together before Thanksgiving, you guys were in the midst of doing these calculations. Have these been passed over to the staff?

MR. ARCARO: They are still in review at GE.

MEMBER CORRADINI: Okay, fine. So the staff has yet to see them.

MR. ARCARO: That's correct. And there is an open RAI that we're answering with these questions.

MEMBER CORRADINI: Right. One follow-up question then, relative to -- if I understood what you said, is you used one computational pool for the hot and one for the cold?

MR. ARCARO: That's right.

MEMBER CORRADINI: Why?

MR. ARCARO: The contain won't work with negative numbers, so if we're analyzing a -40 degree temperature --

(Laughter.)

MEMBER CORRADINI: Wait, wait, wait.

MEMBER STEKAR: You can have a great hit that goes like this, but not like this.

MEMBER CORRADINI: You mean the bloody thing is coated with degree C instead of degrees K, is that what you just old me?

MR. ARCARO: My understanding was it doesn't work for --

MEMBER SIEBER: A Y2K problem.

(Laughter.)

MEMBER ABDEL-KHALIK: How do the results of this new calculation differ or compare to the results that were presented back in November?

MEMBER CORRADINI: We didn't have results back in November.

MEMBER ABDEL-KHALIK: They presented some results and simple back of the envelope calculations showed that this is nonsensical.

MR. ARCARO: Shows that it's what?

MEMBER ABDEL-KHALIK: That the results were nonsensical. If this were to happen in the middle of the summer on a very hot day, it wasn't clear that you could ever meet this requirement of 117 degrees?

MR. ARCARO: I think the results show that 117 degrees, the heat up rate in the control room will be less than the limit in the 72-hour period.

MEMBER ABDEL-KHALIK: Will we have the opportunity to review the details of this new analysis?

MS. CUBBAGE: First, the staff needs to receive it. So that would be the first step. The Staff, we're not planning to present on this topic today because we don't have any new information from when we were at the Subcommittee meeting, but yes, we will come back with the resolution of this issue to the Committee.

MEMBER ABDEL-KHALIK: If we want to see, I'm sure the Staff will share it with us.

MS. CUBBAGE: We will be happy to provide that, when it's submitted.

MEMBER ABDEL-KHALIK: One of the issues that the staff raised as well in that the analyses appeared to be inadequate when the results seemed to be unreasonable.

MS. CUBBAGE: When the response comes in, I'd be happy to provide it through the ACRS Staff and we'll present our conclusions about it later.

MEMBER STEKAR: May I ask a couple of questions? I want to ask one question and also make a point of concern.

The question is do your heat-up calculations for the control room just look at bulk control room air temperature or do you look at temperature within the various cabinets where the heat loads and the sensitive equipment actually exist?

MEMBER BLEY: Actual temperature conditions inside the cabinets.

MEMBER STEKAR: Within the cabinets, not

-- even if it's a lump, I think John's point is if you have a heat-producing element somewhere and the cabinets are going to have a delta T that you --

MEMBER BLEY: Cabinets have power supplies.

MEMBER STEKAR: Right, right.

MEMBER BLEY: They're the heat generators.

MR. MARQUINO: This is Wayne Marquino of GE. The calculations that Mr. Arcaro is referring to are volt temperature calculations. The cabinet calculations take that as an input and as part of the EQ program for ESBWR, when we have the detailed procurement of the equipment, we know how much is going to be in each cabinet, then we do that evaluation.

MEMBER STEKAR: That has not been done yet, but the volt temperature would feed into that.

MR. MARQUINO: Yes, sir.

MS. CUBBAGE: An implementation of the EQ program is post-design certification.

MEMBER STEKAR: The point is they don't have the cabinet designs yet, so they're not quite sure what's there.

The second item that I wanted to bring up is that your presentation today has focused on the control room habitability which is one area of concern that we have.

We also or at least I have concerns regarding room heat up in the remainder of the control building, control building general areas that do have safety-related cabinets in them. And possibly more limiting might be the reactor building where there are even larger -- the averters are out there and you have more safety-related cabinets out in the reactor building areas.

And I think we brought that up at the meeting. The focus seems to keep coming back to the control room which may or may not be the most limiting location.

MEMBER CORRADINI: I think we mentioned it. I think actually in the letter, as we've been going back and forth in the draft, it's there.

MEMBER STEKAR: I just didn't want those other two areas to get lost in the noise with the focus on the control room and if indeed the control room is evaluated as being acceptable saying the whole problem is solved -- it's not.

MEMBER ABDEL-KHALIK: I guess I am just concerned about the superficiality of this presentation. There is nothing here on a technical level for a committee of this type to evaluate or review.

MR. JORDAN: Our approach --

MEMBER ABDEL-KHALIK: Simply your comments that we have developed a model. We've done the calculations and we've responded to the questions.

MR. JORDAN: Our approach on these presentations, again, because of the limited amount of time provided for the four chapters to be discussed was not to get into specific details.

MEMBER CORRADINI: That is partly -- let me interject. In some sense, that's my fault in the sense that we had a two-hour window. We had to go through the four chapters and I told them to address the key concerns that we had discussed from the subcommittee meetings. So in some sense that's at my direction. I think they have enough of a staff out there that if you have questions, you should bring them on and the staff, they look like happy campers out there. They should be ready to answer them.

MEMBER ABDEL-KHALIK: But how would a sort of a presentation or the comments, how would the comments made with regard to the passive heat sink issue with regard to control room habitability that were presented just a few minutes earlier assure a committee of this type that what you've done is adequate?

MR. KINSEY: This is Jim Kinsey from GE Hitachi. I guess to help with that answer, as Amy pointed out, and as the team has pointed out, we've continued our evaluation of these topics since our last gathering. We are giving you a summary of what the results are telling us at this point as we're finalizing those results, that we still need to transmit those to the NRC staff and I assume we'll have some dialogue there regarding those results, but again, we're providing you a status of our activities in this area.

MEMBER MAYNARD: I think that we have drawn more from the Staff's evaluation for this particular one. They haven't received it yet, but I don't think we just take what the applicant says. We have to then talk to the Staff about did they review and what did they review and what was done to confirm what the applicant has said.

MS. CUBBAGE: I would not expect you to be making any conclusions about this topic based on what you're hearing. You're absolutely right.

MEMBER CORRADINI: It's still an open issue. In this one case we heard that you guys were in the middle of it, had some results, were going to talk about them, and still had to do more work, were in the process of transmitting them to Staff. But I think Otto's point is fair is that we -- this is step one, and we have a couple more steps to review before we pass on it. So this is more in the sense of progress report.

MS. CUBBAGE: And Staff is not satisfied at this point. We don't have the information.

MEMBER SIEBER: The place for the details is in the Subcommittee.

MEMBER STEKAR: I don't know if this is appropriate to ask, but it's come up. How far along are you or is it not worthwhile asking in terms of going out for procurement of the DCIS equipment?

MEMBER CORRADINI: That's right. You asked that three months ago. Ask it again.

(Laughter.)

MEMBER STEKAR: Are you close or not?

MR. TUCKER: This is Larry Tucker with GEH. GE's work on the ESBWR as part of the 2010, that phase for certification and certain other activities associated with the design of the ESBWR. There are no funds for equipment. So in terms of business cycle, we're working to the 2010 program.

MEMBER STEKAR: Thank you.

MR. ARCARO: The second topic on control room habitability has to do with actual habitability. The question was how do we maintain habitability during the period where you lose off-site power and the way we do that is through emergency filter units, under a radiation event, or an accident, the control room will isolate the emergency. Filtration units will operate to maintain the system in a habitable condition. We maintain the life support per ASHRE-62. There's a flow rate required to maintain the required amount of -- the required quality of air for the operators in the control room.

And that system also maintains, in addition to the required flow rate, it maintains the positive pressure that's assumed in the dose and leakage requirements for control room dose concerns.

To do that, we maintain 424 CFM and maintain a positive pressure of an eighth of an inch. One of the RAIs that we're responding to had -- was asking about how do you maintain that flow rate and the way we'll do that is have a controlled bleed off point to make sure that we have the required flow going through the control room habitability area to maintain life support for the operators.

The next topic of concern -- or topic of consideration --

MEMBER MAYNARD: I'm sorry, back up just a minute. Control bleed-off point, is that some type of an automatic control or would it be a manual control? I take it it's basically going to be controlling the DP across something so that you keep an air flow through there?

MR. ARCARO: That's correct.

MEMBER MAYNARD: Something has got to be making the adjustments, if needed.

MR. ARCARO: What we'll do is dependent on the leakage of the control room habitability area, we'll size it in order to get that minimum flow rate, so we'll maintain, based on the fan curve, we'll maintain a pressure at the flow, so it would be an orifice that could be adjustable depending on the leakage you get through other paths and it would be located where you could get the flow rate to flush the different spaces to maintain the life support requirements.

MEMBER CORRADINI: This is on the downstream side, am I correct, right, for exhausting?

MR. ARCARO: That's correct.

MEMBER CORRADINI: Because just to go back a little bit, if I remember back in November where we were asking this was we didn't see anything so that led to the questioning of it. So this is still in design or it has been designed?

MR. ARCARO: Still is in design.

MEMBER CORRADINI: Okay, fine.

MEMBER MAYNARD: Now this addresses the long-term, the after the 72-hour time frame?

MEMBER CORRADINI: No, this is during the 72 hours, I think, right?

MEMBER MAYNARD: So what if you don't have a fan running?

MR. ARCARO: You will have a fan running. The fan will be running -- it's a safety-related fan. So you either run it on the safety-related power or post-72 hours you actually have a generator that's going to provide power for that fan.

MEMBER MAYNARD: Okay, so it would basically be a battery -- a battery would be running a fan?

MR. ARCARO: That's correct.

MEMBER MAYNARD: All right.

MEMBER STEKAR: The air supply hasn't been a problem. It's battery powered and it's getting the through put of ventilation, basically the exhaust that brought the question up.

MR. ARCARO: The last topic of discussion had to do with having the heat transfer, evaluate the cooling for fuel bundles in the inclined transfer tube.

MR. DEAVER: This Jerry Deaver. I'll be discussing this issue. What we've done in this area is that the inclined fuel transfer system is, in essence, the same as what we have in BWR6. So in going back and reviewing the work that was performed for those plants, we found that it's bounding for the ESBWR design and the limiting case for heating is with the inclined fuel transfer tube, the sliding assembly in the full-down position and with the water drained off. That's the normal process for equalizing the water line such that you can take out the bundle in that condition. That represents the minimum amount of water that would be in the tube at that time to provide cooling. And the results of the BWR-6 analysis said they had 10 hours to facilitate a repair or a change to get the bundles out.

And there are several options. Either you can open a valve up manually at the bottom of the tube to facilitate flow or you can basically close the drain line off and refill the tube so you have plenty of water. So at this stage, we know that the analysis is bounding and we will be doing the detailed analysis ultimately to establish the hours associated with the ESBWR.

We find that the water height in an ESBWR is much higher than the BWR-6.

MEMBER CORRADINI: Now, you reminded us of this. What plants right now have this sort of arrangement that also have gone through this analysis? I can't remember.

MR. DEAVER: There's Clinton, Riverbend, Grand Gulf, Perry, that vintage of plants.

So at this point --

MEMBER MAYNARD: The ESBWR has the same elevation differences and incline as your BWR-6s do?

MR. DEAVER: It's a different angle and it will be a longer movement of the bundles down to the fuel building, but the basic concepts are all the same. It will have a tube. We'll load the tube with one or two bundles and they'll be trolleyed down to the lower elevation where the fuel building is.

The major difference is that in the BWR-6, they actually had a breach containment. In the ESBWR design, we don't have to do that.

MEMBER CORRADINI: You're still within the dry well?

MR. DEAVER: Yes, that's right. I'm sorry, no, I misspoke.

MEMBER STEKAR: Is the BWR-6 incline transfer tube designed for tube bundles or only --

MR. DEAVER: It is.

MEMBER STEKAR: It is, okay. I'm familiar with the operations. I just didn't know whether it was designed to handle --

MR. DEAVER: Yes, it was.

MEMBER STEKAR: Okay.

MR. KAUFMAN: Okay. I guess that

concludes the Chapter 9 discussion and we're moving to Chapter 10, provided by Jack Noonan. This is a pretty easy chapter to go through, so I would challenge you to go for five minutes.

(Laughter.)

MR. NOONAN: My name is Jack Noonan. I'm a senior engineer in the VOP group at GE Hitachi. We're going to be talking briefly about the Chapter 10 of the DCD.

I just want to give a design overview. Chapter 10 considers all the guidance in NUREG 0800, at least from Section 10-2 to Section 10-47. The turbine generator and pyrocycle systems do not perform any -- or support any -- nuclear safety-related functions.

The ESBWR BOP is based upon a very conventional BWR 6 plant cycle. It's approximately 20 percent larger, about a 1600 megawatt electric gross.

As far as the turbine and generator, the turbine rotors use integral forgings, monoblocks, sometimes. It is minimizing the probability of missile generation. The fully bladed rotor assembly is spin tested at the factory to 120 percent of rated speed. GE has a fairly long history with this design. This replaced the previous design of the shrunk on wheel that was used in the industry prior to the '90s.

The generator is a standard design synchronous generator with water-cooled stator windings and a hydrogen cooled rotor. This is, like I said before, approximately 1600 megawatt electric gross, rated at 1933 MVA.

MEMBER CORRADINI: That's the size the turbine can handle? Can you go back and repeat what you said? I apologize. I was reading something.

Okay, thank you very much.

MR. NOONAN: As far as turbine missile considerations, as I mentioned earlier, we have integral forgings, monoblock rotor. This turbine is favorably oriented so that the hazard zone or the strike zone, as some people call it, of the turbine missiles is away from the containment and reactor building.

BOP pumps are adjustable speed motor-driven feed pumps capable of 33 to 45 percent flow. We use four feed pumps, essentially three running and an installed spare.

We've eliminated the gland seal steam evaporator with improved reliability and actually reduced the dose associated with maintenance on the gland seal steam evaporator.

Overspeed protection system is a fully electronic, redundant, fail-safe, and testable system using 6 probes.

To summarize, ESBWR Balance of Plan is designed with flexibility and basically can be sited anywhere in the U.S. where the design parameters for the cooling water systems are met. It is one basic design.

The design incorporates best practices and industry lessons learned. Some of those that I talked about were the arrangement of the feed pump where you have an installed spare. Basically, the loss of a feed pump would not lead to a reactor trip. We use a feedwater tank which allows you to basically withstand the loss of a condensate pump and not have a reactor trip. There's a full bypass and the plant is capable of high-end load operation.

Basically, you know, the design of the BOP for ESBWR really was with the goal of eliminating plant transients using lessons learned in the industry on events that were initiated from balance of plant transients and improving plant availability through on-line testing and maintenance.

I think I made it in five minutes.

MR. JORDAN: Less than that. Good.

MEMBER STEKAR: That, in the Subcommittee meeting we noted that the feedwater system has in the basic design that we've seen a single low-flow control valve so that if you have to run -- you have to control feedwater at low loads, you're dependent on a single valve.

You said at that time you were considering a possible design modification to install a redundant valve. Has a decision been made yet? And if so, what was the decision?

MR. NOONAN: There has not been a decision made on that.

MEMBER SIEBER: I would think that probably it would not be very severe because of variable speed couplings that you have. You can match horsepower, output of the motor, required to drive the pump to balance the flow.

MR. NOONAN: The low-flow control valve is generally in use when you're not running a feedwater pump. It's during start up. So you don't have that feedwater pump consideration at that time.

MEMBER CORRADINI: Can I ask a different question?

So in a Subcommittee meeting that you probably weren't at, but this is your Chapter 10, so it's kind of fair game, the discussion was to essentially change the operation, to change the feedwater temperature, therefore to give you more maneuverability within the core behavior.

How does that affect the actual system here? Would you change anything in the design we've seen or is this simply a change in the flow rate within the design?

Do you folks know what I'm asking?

MR. UPTON: Yes.

MEMBER CORRADINI: Is it a change in the operation using the same equipment, or is there a modification of the equipment? You were displaced a few months in time and I wanted to make sure there's a connection.

MR. UPTON: Yes. This is Hugh Upton with GEH. What we've actually done is the seven stage of feedwater heating that's been installed in the system. It's always there. It's always warm, but when we decide to valve it in, that's when you're going to get higher feedwater temperatures in the impact reactor power.

MEMBER CORRADINI: Okay, so the feedwater here is there and essentially it's kept toasty and then it's valved in and out as necessary?

MR. UPTON: That's correct.

MEMBER CORRADINI: Okay, thank you. It's a bypass. Primarily a bypass.

Thank you.

MR. JORDAN: Okay, moving on. As I mentioned, we didn't have a specific presentation on Chapter 13, but I'll open this up now if there are any comments or questions that any of the Members may have.

Hearing none, we'll go to Dan Williamson to talk about --

MEMBER CORRADINI: Before you go too fast, so you're asking us about 13, aren't you?

MR. JORDAN: Yes.

MEMBER CORRADINI: So the one thing I'll just remind you all because we have that for the April 9th Subcommittee meeting is that the one thing the Committee was asking about and we were deferred through when we talk about human factors was conduct operation issues that essentially interact with human factor concerns and that would be where we're going to review it in Chapter 18. Correct? I just want to make sure we're on the same page.

Right?

MEMBER STEKAR: Yes.

MEMBER CORRADINI: We delayed questions here with the understanding that we'd bring them up relative to Chapter 18 and human factors.

I just want to make sure the Committee knows.

MEMBER STEKAR: The only -- for the benefit of the Committee, anybody who wasn't at the Subcommittee meeting, the only, I think, technical questions that I have a note on anyway was regarding the survivability of the technical support center for longer than two hours during a station blackout. I think your statement was that the technical support center is not designed to be habitable after two hours. It's strictly a two-hour time window.

MEMBER CORRADINI: So this is an HVAC question relative to the --

MEMBER STEKAR: No, it's actually power supplies.

MEMBER CORRADINI: Oh, power supplies.

MEMBER STEKAR: The entire design is predicated on a two-hour use time window. I only wanted to bring that up for the benefit of some of the other Committee Members who might not have been a party to that discussion.

MEMBER BLEY: We had discussed with you folks at that meeting the idea of the development of your emergency operation procedures being integral to the development of the design and I think you told us this work had just started to get underway and I wonder when we'll hear more about that.

I'm not sure where that was going to get picked up. Do you know?

MEMBER CORRADINI: Let's talk about this.

MR. MARQUINO: This is Wayne Marquino. I'm responsible for the EPGs and EOPs for ESBWR as part of the HFE process. It's covered through an ITAC and it will be performed post certification. We're staffing up and beginning to work on the EPGs and EOPs.

MS. CUBBAGE: And the development process we can discuss at the April 9th Chapter 18 meeting, correct?

MR. MARQUINO: Yes.

MEMBER CORRADINI: Thank you. Okay.

MR. JORDAN: Okay, moving on to Chapter 16, technical specifications. I'll turn this over to Dan Williamson.

MR. WILLIAMSON: Good afternoon. Quickly, we'd like to just brief you on the preparation of the tech specs.

Dan Williamson, GEH team lead for tech spec. development. The tech specs for ESBWR were based primarily on BWR/6 standard tech specs. We utilized what's in existence. The operating fleet is familiar with and licensed too, for the numbering format content, rules of usage and therefore. We also took specific evaluation of the ESBWR systems and the ESBWR analyses and application of the 50.36 criteria for what goes in tech specs, evaluated the ESBWR specifics to ensure that we had the right systems and the right components within the tech spec scope, using the precedence of an existing standard tech spec to establish the form format actions, completion times.

One of the things that wanted to be talked about specifically --

MEMBER SIEBER: Before you skip that last slide or move from it, completion times and surveillance frequencies are based on engineering judgment. There has been a movement for some time to make it risk-based. Had you considered that at all?

MR. WILLIAMSON: We considered several options. Certainly the move afoot in existing fleet is to use risk-based arguments to extend completion times and the Reg. Guide 174, 177, I think it is, provides the application of risk-informed extensions to completion times for surveillance frequencies.

As a base, as a starting point, to facilitate the review and just start in the same ground if you will, as the existing fleet, we utilize existing deterministic-based completion times and frequencies to the extent they apply to the similar systems.

Moving forward in the future, we would expect the same application to dovetail in with the existing fleet on efforts that they're making in the risk-informed tech spec improvement area. We didn't want to spearhead out and do anything too new and different at this time for ESBWR basic certification.

MEMBER CORRADINI: So if there's some sort of result from those efforts this might be modified relative to it?

MR. WILLIAMSON: It would be considered as future activity to be considered.

MEMBER APOSTOLAKIS: Would you do it now? I don't think so. Wouldn't you need more detail to put in the risk calculation?

MR. WILLIAMSON: That is certainly a part of it is the risk -- that the PRA needs to evolve and mature to support those kind of activities.

MEMBER APOSTOLAKIS: When you say the PRA, you mean the PRA for the ESBWR?

MR. WILLIAMSON: Yes, I do.

MEMBER CORRADINI: Dan, let's let Mr. Jakobiac address this.

MR. JAKOBIAC: Rick Jakobiac from GEH. One of the things that we're doing with the ESBWR PRA, as you well know, the design PRA excludes credit for things like operators for the most part. There's a few operator actions that we take credit for, but in general, it's not to the same level of detail in that area as the PRAs that are being used to modify technical specifications in the existing plants.

So rather than do a partial risk-informed tech spec now with a PRA that isn't exactly what the rest of the utilities are using, it's a different level of detail in areas like the humans and the procedures, things like that, doing a partial now and then another partial later, we thought it would be best to use the as-built PRA, if you will, as a basis for going forward with any sort of risk-informing of tech specs.

MEMBER APOSTOLAKIS: I didn't understand the last sentence.

MR. JAKOBIAC: The question was were we going to do risk-informed completion times.

MEMBER APOSTOLAKIS: You are not?

MR. JAKOBIAC: And we are not in the design phase.

MEMBER STEKAR: Let me ask you though, I thought I understood the first part of your discussion saying you took limited credit for human performance in the PRA which I would understand as limited credit for operators manually helping out to mitigate an accident sequence. It's not clear to me what relevance that has to testing and maintenance frequencies and the modeling of durations that equipment are out of service or the frequency of testing. That's not necessarily a human performance conservatism.

MR. JAKOBIAC: By excluding things like operator actions and by using generic data and things like that, it tends to push the risk metrics like risk achievement where it's up very high and you would get very, you'd get more limited benefit from trying to risk inform some of these completion times because the importance measures of the components that you're looking at are artificially high.

We know they are artificially high because we haven't taken credit for certain types of recoveries.

MEMBER STEKAR: You mean real live?

MR. JAKOBIAC: Real live recoveries. So --

MEMBER SIEBER: Wouldn't that be better than an engineering judgment? There's no real basis for the completion times and surveillance intervals for the engineering judgments.

MR. JAKOBIAC: I think that's a good point, but one other thing that we have to consider with this is it's been very difficult for the existing plants to risk inform their technical specifications. That's a very long, arduous undertaking. And if we were to combine a new plant license with a partial risk informing of the technical specifications, I think we would be at a different time line than we are right now.

I think we'll get there, but not on the certification time line.

MEMBER STEKAR: In the PR, we haven't seen the PRA yet, so we have a version, but it's -- what I wanted to ask is you mentioned generic data. The testing frequencies, obviously, are specified in the tech specs, so you must be using those.

MR. JAKOBIAC: To the extent that they apply, yes.

MEMBER STEKAR: Okay. Maintenance unavailabilities are based on historical data from operating plants or are they based on estimated frequencies where the tech spec allowed outage times?

MR. JAKOBIAC: The tech spec allowed outage times are associated with it and we also have, in our design specs, target reliability values that help inform what we would put the unavailabilities at.

MR. WILLIAMSON: We also wanted to talk specifically about the passive systems, the surveillance that are conducted on the passive systems and the frequencies. As an example, we'll talk about GDCS specifically. And again, we applied precedence in our engineering judgment, precedence for similar systems, similar applications in establishing our surveillance and surveillance frequencies.

In the case of the gravity-driven cooling system, there's an inspection for flow obstruction, a 10-year surveillance, typical of systems that are -- that don't experience flow. You don't have a quarterly pump flow, systems that rely on FME, foreign material exclusion, and cleanliness. Containment spray headers have a 10-year frequency. Similar systems in AP1000 have a 10-year frequency.

MEMBER APOSTOLAKIS: Where is this 10-year frequency specified?

MR. WILLIAMSON: In the surveillance requirement for the --

MEMBER APOSTOLAKIS: No, no, no. You said there is a basis some place.

MR. WILLIAMSON: Precedent. Similar systems, passive systems that don't experience any flow or any mechanism for degradation have historically had a 10-year inspection for flow obstruction.

MEMBER APOSTOLAKIS: Such as?

MR. WILLIAMSON: Containment is the one that comes to my mind. Containment spray is one, is the classic example, I think. There are other systems that don't -- for instance, the AP1000 has similar systems to the ESBWR and have a similar 10-year frequency applied for.

MEMBER CORRADINI: So let me just broaden this question because this one, I don't know enough, but I want to make sure I understand the thinking process of you guys.

So now I've gone from a current light water reactor where the only passive system, the notable passive system is the building, the containment, and all associated things. And there, there's a containment leak rate test every 10 years. So now I was looking at the frequency here, so now you mentioned this one and I was looking down at the isolation condenser. So is the basis to use what is currently passive systems or safety systems that have a passive attribute and use that sort of frequency or is there a -- what is the technical basis for rather than history says we did it and it seems okay and we'll keep on doing it that way?

MR. WILLIAMSON: That would be the engineering judgment basis. There are other preventive maintenance activities.

MEMBER CORRADINI: Right, I can imagine.

MR. WILLIAMSON: There's ISI and IST on the check valves and flushing of the lines that occur, but the tech spec required operability verify there's no obstruction is a span of 10 years.

MR. DEAVER: I think if you look at the system, the geometry of the system with the gravity-driven pools and such and the screens that basically allow venting at the top, there's just not any real opportunity to -- the screens have limited whole sizes and such. The opportunity to get debris into the pools in the first place is very limited so flow obstruction, you know in a totally stainless steel system just seems to be a remote possibility.

MEMBER CORRADINI: I understand. Can you remind me for the gravity, for the GDCS what is the pipe diameter coming into the vessel? I forget now?

MR. DEAVER: It's six inches.

MEMBER STEKAR: Are these the only access points with regard to foreign material exclusion?

MR. DEAVER: Well, we have valves, but basically the piping that goes from the pool to the vessel, there are only maintenance valves, squib valves, check valves, that sort of thing. So the only opportunity is you are somehow taking a valve apart and you happen to leave something inside. That would be the only opportunity.

CHAIRMAN SHACK: And historically, given the importance of this system, historically you believe that a 10-year frequency is adequate?

MR. DEAVER: Yes, and the valves basically, the squib valves basically, we just check the charge to make sure that that's operable. We don't really need to take the valve apart. The check valves get stroked in every outage and such. So there's not much need to do maintenance on these valves in the first period.

MEMBER ABDEL-KHALIK: There is no other activity during an outage where other foreign material can get into the system and cause partial blockage?

MR. DEAVER: That's what I find hard to imagine because each location of the pools and the vent being right at the top of the ceiling of the containment and the limited access with the perforated holes in the plate to prevent debris from entering into the pool. So there just doesn't seem to be any opportunity. Somebody would have to purposely do something to cause an obstruction.

MEMBER STEKAR: This is just a point of personal ignorance and maybe somebody on the Staff might know, what are the current requirements for injection flow verification from pressurized water accumulators, actual flow verification testing? Does anyone know?

MR. HARBUCK: I'm from the Staff. My name is Craig Harbuck. There are no pressurized water accumulators.

MEMBER STEKAR: We're talking about the current plants, existing plants.

MR. HARBUCK: That's another passive system.

MEMBER STEKAR: That is a very, very similar low-pressure injection type of system. So in terms of looking at precedent, I would certainly be curious about what the requirements are for functional flow testing of pressurized water reactor accumulus. They're very, very similar.

How do you verify it?

Periodically, you actually have to open a valve and make sure the level of the accumulator goes down and level in the vessel goes up. I was just curious, how frequently people do that because I know some years ago when I was operating we did one accumulator per outage per year.

MR. KINSEY: Dan or Jerry, maybe you want to talk about flushing water down the line?

MR. WILLIAMSON: I just pulled up the Westinghouse existing fleet Westinghouse tech specs for 351, their accumulators. And they have no flow surveillance. They have a verified nitrogen pressure every 12 hours, verified boron concentration every 31 days, and verified the powers are moved from the isolation valve every 31 days.

MR. WILLIAMSON: I happened to have been in the same plant that he was and I remember doing this test.

MEMBER STEKAR: But that was all. I was

curious what's current. I'm not trying to be contentious. I'm just curious.

MR. KINSEY: At a PWR, when you do that test, when you inject, you're actually doing it to check the check valve.

MEMBER STEKAR: That's right. But it's the same --

MR. KINSEY: Same outage.

MEMBER SIEBER: But the flow rate is a function of --

MEMBER STEKAR: Is that still the case on existing plants?

MR. WILLIAMSON: That is based on the BWR at I worked at.

MEMBER STEKAR: That's my case, too, but that was 30 years ago.

What's the third bullet under the GDCS?

MR. WILLIAMSON: What would be the ASME. The ASME components have this requirement for stroking and you do that for the flow test and the case --

MEMBER STEKAR: But it also functionally verifies point to point. I mean water goes down here. Water goes up over here, so you're actually verifying the continuous flow, even though you're doing the test to verify a particular component.

MEMBER SIEBER: The only way to measure that is to measure the change in level.

MEMBER STEKAR: Yes.

MEMBER MAYNARD: I forget the frequency and it's not all with the cumulative tech specs that cover the surveillance that you do for flow because you also have to flow through the check valves to make sure that the check valves open and stuff there. So there are periodic --

MEMBER STEKAR: I think that is another --

MEMBER MAYNARD: I forget the frequency.

MEMBER STEKAR: It's just a point that if the 10-year frequency for the gravity-driven, the GDCS, is as you mentioned based on industry practice or precedent, I'm hoping that we're looking broadly enough across industry practice and precedent for similar types of passive injection systems.

MR. WILLIAMSON: And also, the ASME requirements that apply to these passive components, same tests.

MEMBER MAYNARD: I've got a question

primarily for the staff as to how much of the tech spec is approved as part of the design cert. versus how much for the -- as part of the COL.

MR. HARBUCK: This is Craig Harbuck again. Most of the tech spec should be approved during the design certification process. However, there are some things which cannot be done at that time. The surveillance for the passive ECCS should be established during the design certification as well as the frequencies.

MEMBER MAYNARD: It's important to get the frequencies right at this point.

MEMBER SIEBER: It would be nice.

MEMBER STEKAR: Frequently enough because of the pressure later to make them less frequent.

MEMBER CORRADINI: I think we can.

MR. WILLIAMSON: Isolation condensers is another one that we briefly mention. We do have a heat transfer test that's done at a frequency will test one of the heat exchanger every 24 months to confirm the transfer coefficient remains within the analysis assumptions.

MEMBER CORRADINI: In 30 seconds, can you remind me what that test is? We were debating privately here. Remind me of what that test is?

MR. WILLIAMSON: It will be a test to confirm the heat exchanger transfer coefficient.

MEMBER CORRADINI: And it is conducted how?

MR. WILLIAMSON: That we don't have the procedure drafted. We have in the bases, I had that available to -- what's outlined in the bases. The temperature sensor located downstream of the condensate return isolation valve and the differential pressure transmitter on the condensate return line may be used to provide the test data. A brief summary of the components, there are ways to do the test that have been evaluated by engineering when we propose this to ensure that the tests could be performed.

MEMBER CORRADINI: But let me just push you a bit and so here's where I'm going back to history. So I'm going to get the wrong plant. It's not Oyster Creek, right? It is which plant?

MR. WILLIAMSON: Dresden.

MEMBER CORRADINI: Dresden.

MR. WILLIAMSON: I suspect.

MEMBER CORRADINI: So how did,

historically, Dresden check their isolation condensers and I would assume you would have a similar sort of test. What I guess we're worrying about, what I'm worried about, I don't know about anybody else, is the frequency of it again, but you've already said it's a 24-month period for each of the 4, so over 8 years, you'll check them all and also the test because this, to me is an important test to verify you've got capacity.

So if you can point me to something I'm happy to go read.

MR. WILLIAMSON: Meaning the Dresden procedure or --

MEMBER CORRADINI: Just to understand because I would think that knowing nothing else, you'd use something, a standard similar to what you used in the past.

MR. MARQUINO: This is Wayne marquino, GE. So Dan Williamson is describing what parameters we will measure during the test, we are still working through the more specifics about the procedure in terms of what operating point it will be. And you had a request on trying to get you the procedure for an operating plant and we'll work with our potential customers that have isolation condensers to get that information to the staff.

MEMBER CORRADINI: We're going to see you for a little bit longer, so I don't think you're going anywhere, but yes, we would like to see that.

MEMBER BANERJEE: I have a question. I had to go to a meeting, so maybe I missed it, but is there some tests being done for gas intrusion in these GDCS lines?

MR. DEAVER: Let me answer that. We're going to control that basically by geometry. The squib valves will be the low point in the system such that we'll slope the lines going towards the vessel such that any gas entrainment in the nozzle or the piping going to the squib valves will go back into the vessel. The gas will not stay in the line and then likewise, coming up from the squib valves, because of the pools and the venting allowed by the pools, if we slope the lines upward, then we don't get any accumulation of anything. We always vent the system such that there's no way to entrap gas or air in the line itself.

MEMBER MAYNARD: I would be surprised if the Staff doesn't require either at the design cert.

stage or at the COL stage some type of monitoring or testing of this. There are issues with you can do it by design, but by the time you do the design and that you install it, it depends on design tolerances sometimes. Sometimes you may have designed a line to be where you know where the high point would be or whatever, but in reality with tolerances and -- they don't end up that way. So there has to be at some point --

MR. DEAVER: There has to be a final check or inspection.

MEMBER CORRADINI: This is one inch in a hundredth slope, right?

MR. DEAVER: Yes.

MEMBER BANERJEE: That's not much of a slope. I thought it was like a 20 degree --

MEMBER MAYNARD: There are some current issues with plants right now with a real low slope and that the construction tolerances and even the pipe not being straight, I mean you may have one end that's higher than the other, but the whole pipe is not at that angle, so there's --

MEMBER SIEBER: We occasionally find pipes that are bowed.

MEMBER MAYNARD: Yes.

MEMBER BANERJEE: And this is what, an 8-inch pipe?

MR. WILLIAMSON: Six inch.

MEMBER BANERJEE: Six inch. And we have relatively short runs coming out of the vessel until we get to the maintenance valve and then into the squib valve. Those are very short lines.

MEMBER CORRADINI: I think we are going to return to this one in Chapter 15 questions. I seem to remember somebody bringing up this question in other contexts.

MEMBER BANERJEE: In different contexts.

MEMBER CORRADINI: Yes. But we won't forget it. This one is important for a number of reasons relative to performance of the systems. I agree with that.

MEMBER MAYNARD: This is critical.

MR. WILLIAMSON: We have already mentioned several times squib valves. Obviously, there's squib valves and we have the standard surveillance that apply to squib valve applications today with verifying continuity and the ASME requirements for sampling, batch replacement, standard precedent applied for squib valve testing.

Any more questions? I think we are probably eating into the Staff's time already.

MEMBER CORRADINI: I think we are -- let me go around and make sure that the Members have -- for the moment, are you guys okay?

All right. Thank you very much.

MR. WILLIAMSON: You're welcome.

MEMBER CORRADINI: We'll have a change in the team.

(Pause.)

MS. CUBBAGE: Good afternoon, Amy Cubbage, Lead Project Manager for the ESBWR design certification. It's a pleasure to be back again.

(Laughter.)

I'd like to introduce some of the members of the Staff over here to present with me today. Gorge Hernandez from the Balance of Plant Branch and NOR; David Shum, also from Balance of Plant Branch; Craig Harbuck from our Tech. Spec. Branch. We also have a number of members of the Staff in attendance to address any questions you may have on top of this that they're going to be addressing in the presentation.

So I'll give you just a little summary of what we're going to be presenting. We're going to be covering the topics of spent fuel passive decay heat removal. That was a topic of interest at the previous meeting. Inclined fuel transfer system, instrument and service air, hydrogen water chemistry, emergency lighting. There was a question on that. I'd like to update you on where we're at with that.

On the steam and power conversion system for Chapter 10, we don't plan a presentation there. If you have questions, we have a reviewer for most of that, and we have others here as well.

Chapter 13, again, no presentation planned.

Chapter 16, Craig will be presenting some of the topics of interesting including surveillance requirements for ECCS and surveillance frequencies.

I'll turn it over to Jorge for our first slide here.

MR. HERNANDEZ: Good afternoon. My name is Jorge Hernandez from the Balance of Plant Branch in NOR. I'll be briefly going over updates on the -- on our review for the spent fuel pool decay heat removal and also touch on the subject of the incline of fuel storage transfer system which were topics that were discussed as Amy mentioned in the Subcommittee meeting.

After the Subcommittee meeting, we reviewed the applicant's boiler analysis for the spent fuel pool. In summary, essentially the analysis concludes that following the loss of force going there will be at least two meters of water of active fuel. GEH calculated that 1690 cubic meters of water would be lost during that 72-hour period. And this assumes that the spent fuel pool is full at capacity and there is one pool for offload also.

They also assume that the transfer gates are closed and the analysis starts at the normal water level which is 14.35 meters.

MEMBER BANERJEE: The two meters, is that the collapsed liquid level or --

MR. HERNANDEZ: Yes. That will be collapsed without voids.

They also specified three alarms. There's one at the low level which is just below the normal --

MEMBER BANERJEE: How high are these fuel stacks?

MR. HERNANDEZ: Three point five meters. And the normal level is 14.35 from the bottom of the pool.

MEMBER BANERJEE: And where does the boiling start on this?

MR. HERNANDEZ: At 14.35. From the bottom of the pool. They would essentially lose 8.85 meters of water.

MEMBER BANERJEE: Sorry, is there boiling within the fuel or is it only boiling --

MR. HERNANDEZ: At the top.

MEMBER BANERJEE: At the top. So it's just -- I'm just trying to understand. So this is a pool full of water. In it, there's some fuel, right? Now you've lost convective cooling so eventually it has to boil. Natural convection can't take care of it and there's not enough -- is it boiling within the fuel bundles themselves or is it just boiling in that two meters above because to due to lack of gravity?

MR. HERNANDEZ: This is part of the -- there will be some boiling at the -- I believe that there --

MEMBER BANERJEE: In the fuel itself?

MR. HERNANDEZ: The thermohydraulic

analysis will show that there is enough flow going through the racks such that there won't be trapped voids within the racks and so they won't just all go to the top.

MEMBER CORRADINI: So just to repeat so I'm clear. Your boiling would first initiate at the top of the fuel or near the top of the fuel, not exactly at the top of the fuel, but near the top of the fuel. Is that correct? I think that's what Sanjoy is asking.

MEMBER BANERJEE: And then it will propagate down or how far down?

They have two meters of water above.

MR. HERNANDEZ: The boiler analysis was really a bulk type of analysis, assuming that there's a heat source within the pool. And essentially you're boiling an inventory of water so it doesn't go specifically as to the racks themselves or the fuel cells themselves.

MEMBER CORRADINI: Just to circle back to what Professor Banerjee was asking. I think his point is he's trying to understand the source of the vapor and I think the source of the vapor is probably not at the dead 3.5 meters, but a few right below that because your delta T would be somewhere around in there to start the boiling vessels.

MR. HERNANDEZ: And like I said the analysis is not specific as to where exactly.

MEMBER CORRADINI: I understanding.

MEMBER BANERJEE: It is similar to analyses that you do for other spent fuel pools?

MR. HERNANDEZ: Well, normally, you won't go into a scenario where you're boiling the pool for active plants, so you usually determine an analysis that looks like normal operating conditions and usually you have safety-related force cooling.

MEMBER BANERJEE: So why has this not got safety related, because it's passive?

MS. CUBBAGE: It is a passive plant.

MEMBER BANERJEE: That's why there is none. So this is sort of a unique situation in that sense, right?

MR. HERNANDEZ: Correct.

MEMBER BANERJEE: And you haven't done a -- at some point, there will be a detailed thermal hydraulic analysis done of this.

MR. HERNANDEZ: What I've seen so far is a thermal hydraulic analysis for normal operating conditions, assuming that you have forced cooling.

MEMBER BANERJEE: That's easy.

MR. HERNANDEZ: There is no analysis for that for the emergency scenario.

MEMBER BANERJEE: And in the current plants, there is a backup system which is pumped, right? Or not.

MR. HERNANDEZ: Correct.

MEMBER BANERJEE: Or does it depend on boiling?

MR. HERNANDEZ: You essentially rely on forced cooling for all the plants. In the AP1000, that's a reactor that has also similar design which you also boil in pool. Normally, you don't expect the pool to be boiling.

MEMBER BANERJEE: It's interesting to have a boiling pool for the fuel.

MEMBER MAYNARD: I am a little confused. Even with the existing plants, they've all had to do coping studies for station blackout and they've all done --

MEMBER SIEBER: There's no cooling at all. They just heat up the bulk water.

MS. CUBBAGE: I am not an expert in this

area, but I know this is unique in that it's a 72-hour period rather than the --

MEMBER SIEBER: It's a design basis condition.

MEMBER MAYNARD: But as far as the ability to calculate the heat transfer and the boiling, how long you can --

MEMBER SIEBER: Pretty simple.

MEMBER BANERJEE: But once you've been boiling for 72 hours, I mean I don't know what's happening to this. You've lost quite a bit of water by then.

MEMBER CORRADINI: That's the whole point. They go from the 8.5 to the 2.

MR. HERNANDEZ: Right, and at that point you hook up the emergency makeup which is the --

MEMBER BANERJEE: But this is not fresh fuel you're talking about.

MEMBER ABDEL-KHALIK: Sanjoy, a minimum of two meters is maintained above the top of the active fuel, just hydrostatic pressure difference between the top of the pool and the top of the active fuel is roughly 3 psi. And the corresponding change in saturation temperature between the free surface of the pool and the top of the active fuel is roughly 10 degrees F. So you may not have boiling inside --

MEMBER BANERJEE: That's what I was asking.

MEMBER ABDEL-KHALIK: And you get essentially a boiling as the pressure decreases as you go up.

MEMBER BANERJEE: The question I was asking is do you get boiling.

MEMBER SIEBER: As opposed to boiling in the fuel, the assembly itself -- because the whole pool is boiling.

MR. HERNANDEZ: The water heats up in the fuel, but it will --

MEMBER STEKAR: I have a more basic question since I don't understand how to boil water.

(Laughter.)

MEMBER STEKAR: There was some -- I'm useless.

MEMBER BANERJEE: Do you know how to percolate?

MEMBER STEKAR: No, no, that's a mystery. Anyway, there was a discussion in the DCD, there are a couple of places where it said that the -- my question was that the heat-up analyses were performed using 20 years' worth of spent fuel although the current design capacity is only 10 years, right? Is this calculation done -- you said you used spent fuel full capacity. Is that 20 years' worth of spent fuel or is that 10 years' worth of --

MR. JORDAN: Twenty years.

MEMBER STEKAR: Twenty years. Okay, thanks.

MR. HERNANDEZ: I think GE rectified that during the Subcommittee meeting.

MEMBER STEKAR: I just wanted to make sure that where you say at full capacity was 20 years.

MR. HERNANDEZ: Yes. Like I said GE specified three safety-related alarms. There's the low-level alarm just below the normal level, but within the two meter range, so it's not going to be below, two meters below the normal level. There's the safe shielding alarm as well that is located above 3.5 meters or 10 feet above the top affected fuel to meet shielding requirements.

And there's also a type of factor fuel elevation alarm which is essentially to the arrow, temperature-related alarms that are announced in the main control room and they would alert the operators that the fuel has been exposed.

The Staff requested GE to address a postulated drain. This was based on comments from the ACRS of the Subcommittee meeting as well, for them to address a scenario in which you would drain -- it's a postulated drain through the gates and also to define the distance between the top of active rule and the bottom of the gates.

There's a statement in the DCD that says they will have at least 10 feet of water. We just want to know what's happening. How much they will have and how much margin they will have.

With regards to the inclined fuel transfer system, GE --

MEMBER MAYNARD: Sorry, is that still an open item or an issue that's being --

MR. HERNANDEZ: Yes. They haven't addressed that.

Again, based on the comments from the ACRS during the Subcommittee meeting, we had a discussion with GE regard the postulated loss of power to the transfer to system and with two assemblies stuck inside the transfer tube. They have indicated that the analysis for the ESBWR is bounded by the BWR6 which they have already mentioned during this full Committee meeting. And that it provides at least 10 hours of passive cooling before they start boiling.

The analysis basically assumes that the assembly center is at the bottom of the tube and that the transfer tube is partially planing. They have also indicated that they makeup water can be added via the upper or the bottom valves or the upper manual valves and that doses have been analyzed.

We found that there is sufficient time and ability to provide makeup. It's acceptable. That's basically it.

MS. CUBBAGE: David Shum.

MR. SHUM: Good afternoon. My name is David Shum. I'm a senior engineer and I have reviewed the instrumentation and service in the systems project, the ESBWR.

By design, the systems are non-safety related systems and they do not perform safety-related function. They're not considered as a candidate for the RTNSS, and are not required to achieve or maintain safe shutdown of the plant.

MEMBER CORRADINI: Can I ask a question there just to -- it's for my edification. What qualifies a system to be part of a RTNSS system, part of the set of RTNSS systems?

MR. SHUM: They have to be usually as a defense-in-depth and have to make sure those are criteria specified in the Chapter 19 because there are five criteria.

MS. CUBBAGE: We're going to get into a lot of information on the RTNSS systems at a subsequent meeting, but you know in a nutshell -- this is regulatory treatment of nonsafety systems and there are different ways that a non-safety system in a classic plant could be elevated to raise additional regulatory control and some of it there are deterministic criteria that's being used as a post-72 hour defense-in-depth system.

MEMBER BLEY: When will we get to those?

MEMBER CORRADINI: That's what I was going to ask you.

MS. CUBBAGE: June.

MEMBER CORRADINI: June.

MS. CUBBAGE: Chapters 19 and 22.

MEMBER CORRADINI: Twenty-two.

MS. CUBBAGE: Twenty-two of the Staff's SER. It's covered in 19 of the applicant's DCD.

MEMBER CORRADINI: Thank you. We'll talk about that then, but the one thing that just comes to mind if we're looking at these systems under design assumptions, if those design assumptions haven't been realized in practice in operating plants, could that elevate something to this list?

MS. CUBBAGE: I'm not sure of the question.

MEMBER CORRADINI: Instrument air systems often control -- and I don't know everything that's air controlled here, often control things that would be important except they're fail safe. But the way they're fail safe is if pressure goes from full pressure to zero, everything goes where it ought to go. If it either decays very gradually or the system is not completely clean, that assumption no longer holds. If it decays gradually, things happen in sequence that wasn't designed. There's plenty of events showing that. If the system gets moisture or debris in it, even at full pressure the outlet of the compressor, odd things happen one at a time. Things get starved for air and things move around. So the assumption that it's fail safe might not -- hasn't been realized in practice across the board.

So my question was if, in fact, there are things here that might matter if that assumption of fail safe weren't true --

MS. CUBBAGE: Well, due to the nature of the passive plants I think they've made strides to not require any of these active systems to be operable for the safety systems to function. I'd have to call on GE Hitachi or Dave to explain more about failsafe nature.

CHAIRMAN SHACK: But I think Dennis' question was are they designed -- if they're not designed to operate, they're designed to fail safe and if they don't fail safe, is there a problem.

MEMBER BLEY: Would that put you on the RTLSS list then?

MR. ARCARO: This is Mike Arcaro from GEH. The instrument air is not RTLSS. The safety function is for those loads is performed by accumulators, so that's why the high pressure air systems aren't safety-related, aren't RTLSS. We did do an --

MEMBER BLEY: If it worked for the accumulators, they might be?

MR. ARCARO: The URD and the design has check valves or isolation between the air system and the safety loads and then there is accumulators. So if we didn't have the accumulators, then they would be performing the safety function.

MEMBER ARMIJO: But the last bullet on your chart there is a very strong statement and I'm just wondering if that's really the Staff's position that failure of the AIS or SES does not compromise any safety-related system or component, nor does it prevent a safe shutdown.

MR. SHUM: Yes, that's what we understand.

MEMBER ARMIJO: Is that your conclusion that --

MR. SHUM: Yes.

MEMBER ARMIJO: That's a very strong statement.

MR. SHUM: Based on what we understand about the system.

MS. CUBBAGE: I think this ties into the comment from GE Hitachi about the accumulators and the nature of the arrangement of their pneumatic valves.

MEMBER MAYNARD: I think that probably for this design, they are not really relying on it. They rely more on the accumulators. For other plants, this really is -- any operator will tell you the instrument air system is one of the most important nonsafety systems that you've got. But for the way this plant operates, in the accident mode --

MEMBER STEKAR: It's not clear. It's not clear.

MEMBER BLEY: We haven't seen enough for it to be clear and I guess the thing that keeps bringing it back to me is the key assumptions that the check valves protect you from everything, that the accumulators back you up, we've got systems out there that have the same kind of things and have had significant problems. So it just kind of feels like operating history is disconnected from the review and I don't know if that's true or not.

MR. SHUM: Normally, your accumulators supply from the high pressure and larger supply systems, normally. This is the case you've got the air for the accumulator.

The instrumentation -- only connected to that system, the high pressure, supply system outside of the container as a back up.

MEMBER BLEY: Normally, everything works great. There's always been, it seems, it appears there's always been a design assumption that the way air fairs is suddenly you lose a compressor and you have no pressure. History tells us it fails in many different ways and that way is well protected. All the other ways may be not.

MR. SHUM: I agree with you, but this is non-safety system. Our job is safety, our concern. If it doesn't -- if the system fails, isn't compromised, and safety-related system or event of the safe shutdown, our job is done. I don't care whether they have to shut the plant down or not. That's why GE has to answer the question.

MEMBER BLEY: You've also claimed that there's no way these are written systems and maybe that's true, but what you just said was they would be if you didn't -- if the accumulators didn't work.

MEMBER STEKAR: Let me ask something else to get through this. Was there instrument air in the PRA model? Does it model in the PRA?

MEMBER BLEY: And alternative modes of failure model.

MR. WAKORVIAK: Instrument air is modeled in the PRA. The alternative failure modes that you're specifically talking about are captured in the data for air-operated valves, so we don't specifically have something that says the accumulator is at half pressure or something like that.

MEMBER BLEY: I'd urge you to think about that.

MR. WAKORVIAK: I understand --

MEMBER BLEY: It's a common effect.

MR. WAKORVIAK: I understand what you're looking at, but we've got -- we can look at those sorts of things.

The Staff has asked us in RAI about what we -- about any other systems that may have what you're talking about is covered under criterion E of RTLSSs adverse system interactions. And what we've said so far in that at this stage of the design it's difficult to tell what adverse system interactions there are because we don't have something to look at and that's a very component-specific FMEA sorts of things. You have to have something to look at to see if there's an interaction.

We certainly wouldn't design in an interaction like that, but sometimes because of engineering you have to have things like that.

So the staff has asked for some sort of assurance that these things will be looked at later. We're in the process of answering that RAE and before we get to Chapter 22, you'll have our response on that.

MEMBER BLEY: Okay, thank you. One last thing from me and I won't say anything more about the air system. When we first went through this in the Subcommittee meeting, the impression I got was this didn't get looked at very hard because it's nonsafety and it's not RTLSS.

But the review was based on sort of a cartoon of the system which was very incomplete and that nobody said gee, where's the real drawing of this system? The bypass valves was where we started on this. Are there bypass valves? No, there aren't any on this picture. The picture was a cartoon. It wasn't a real system drawing. It's troublesome.

Go ahead.

MR. SHUM: I agree with you. When we

came to the Subcommittee meeting, we -- our conclusion at that time was based on Rev. 3.

MEMBER BLEY: Okay.

MR. SHUM: In Rev. 4, they decided --

MEMBER BLEY: But you didn't even have an RAI on what's the system look like. That's what bothered me.

MR. SHUM: By looking at the system, what I call Mickey Mouse diagrams --

MEMBER BLEY: Fair enough.

MR. SHUM: It looked all right to me.

MEMBER ABDEL-KHALIK: So the determination that this system does not perform a safety-related function is based on -- and let me just guess the fact that if you have an instrument air operated valve in a safety system that is required to either fail as is, fail open, or fail closed, that this will be -- that this will indeed happen.

MS. CUBBAGE: You do not need the instrument air system to be operable for any of the safety valves to function.

MR. SHUABI: This is Mohammad Shuabi from the Staff. I guess it's important. I'd like to add that for example, when we do these chapter reviews, aside from the PRA and aside from the RTLSS discussion which will come later, this is design basis space type review. So what we're looking for is is there a safety function that needs to happen? Is there a safety function of this valve of the system of this component that we need to look at to make sure that it's done correctly, it's designed correctly, it's provided and described correctly in the DCD.

In this case, there is not a safety function that the system is serving. The other thing that we look at is is there something that the system can do to prevent a safety system from performing its job? That's another thing that we do when we look at these systems and what you're hearing there is that number one, this does not provide a safety function, and number two, our conclusion is that it does not impact the safety function.

Now when you get into PRA space and when you look at severe accidents, other considerations come in to play and that's where the comment was made that in that area they do some modeling and they do a little failure modes and things like that, but in a design basis space, we're looking at the safety-related, the safety functions that these have to provide to meet the regulations.

I just want to make sure that there's a distinction between those two types of review.

MR. SIGALA: This is John Sigala. I'm the Chief of the Balance of Plant Branch.

I did also want to point out some other things. I mean there's been a long history of operating experience on instrument air. It started back with Generic Issue 43. There was an OAD study that was done on air system problems. That turned into Generic Letter 88-14. We had all licensees go out there and look at their systems, look at an instantaneous loss of instrument air, a loss -- a gradual loss of instrument air, an increase in air pressure to see if that would cause failures of components. Licensees went out and did that. We have a Reg. Guide 1.68.3 which is initial testing for instrument air systems.

GE, I believe, has committed to that in their initial test program. That has them do this testing when they build the plant to do a gradual loss, an increase in pressure and then an instantaneous loss.

We do look at operating experience. We have issued Generic Letters, information notices on these topics. We do take that into account when we do our reviews. We do factor that into updates to the SRPs. But we believe, if you go back to the maybe earlier slide, the continuous monitoring of the air quality, we believe prevents a lot of these -- or allows these degradation issues to become aware. A lot of the problems from operating plants were because the instrument air systems were not properly taken care of over long periods of time. You had corrosion products build up. You had moisture problems. You had desiccant filter issues, clogging up valves and then when they would lose instrument air the valves wouldn't shut.

I think these are all the issues that you guys are concerned about and we are too. And I think that the continuous monitoring of the air system, the periodic testing in accordance with the ANSI standard, those are all things that are built into our SRP as ways that the systems are maintained so that you minimize these kinds of effects from happening.

There was a research report that was done a couple of years ago that looked at hey, it's been 20 years since we've issued Generic Letter 88-14. Have we seen any operating experience since then, since plants fixed the problems, have we seen any operating experience that lends us to believe that we need to issue another Generic Letter or what not. The conclusions out of that was that that was not the case, that we have not seen a resurgence of instrument air problems and I guess the Staff has done a review. We feel like this design, with the Reg. Guide 168, initial testing, and the periodic looking at the moisture content and the periodic testing, we believe that this is adequate.

MS. CUBBAGE: I just want to briefly cover an issue of emergency lighting. Since the Subcommittee, we did get clarification from GE Hitachi in an RAI response. The emergency lighting and the remote shutdown area is fed from safety-related 72-hour power supply in a similar arrangement to the main control room.

We're reaching resolution on that issue pending GE updating the ITAAC to include this item.

MEMBER BANERJEE: Is this UPS of batter

supply or what?

MS. CUBBAGE: Amar?

MR. PAL: Amar Pal, NRO/DE. Yes, these are backed by UPS for 72 hours.

MEMBER BANERJEE: But what is the UPS system?

MR. PAL: Uninterrupted full Power Supply.

MEMBER BANERJEE: What is it?

MR. PAL: Battery.

MEMBER BANERJEE: What kind?

MR. PAL: BRLA. Valve regulated lead acid battery.

MEMBER BANERJEE: What?

MS. CUBBAGE: Valve regulated.

MR. PAL: Lead acid.

MEMBER BANERJEE: And these are similar capacities to the existing lead acid system?

MS. CUBBAGE: A very large battery.

MEMBER CORRADINI: We needed you on this Subcommittee. You would have had fun at this point.

MS. CUBBAGE: We did cover this at a previous meeting and he's nodding his head. Our lead electrical reviewer is not here, but --

MEMBER CORRADINI: Is there a GE person that can --

MEMBER BANERJEE: I'm really asking is there any qualitative difference between what we do today. And I suspect that it does.

MS. CUBBAGE: The technology is different in that these are the valve regulated batteries. They're large batteries. Beyond that, I need to call on GE.

MEMBER SIEBER: In a lot of plants today, you have a light with an integral battery that's plugged in if the power supply fails, the battery will take over. It depends on if there's enough light in the room or not, it turns on, if there isn't.

MR. UPTON: Amy, this is Hugh Upton with GEH. I don't believe we have our experts here in the electrical uninterruptable power supply system. So we would have to defer that until we get the right experts in.

MEMBER CORRADINI: At the time when we were explained this and we quizzed them, we were satisfied.

MEMBER STEKAR: Is there light at the

remote shutdown panels for --

MS. CUBBAGE: Yes.

MEMBER STEKAR: How you get it there, I don't care.

Are the lights on for 72 hours?

MS. CUBBAGE: The lights are on. It's powered by that --

MEMBER BANERJEE: I just wanted to double check that the source of the light is there.

MEMBER STEKAR: The source of the light is the source of everything else that's important in the plant. If that's not there, there are big problems.

MS. CUBBAGE: And there is additional detail in Chapter 8 of the design cert. document and the Staff's safety evaluation that we briefed the Committee on in the fall.

MEMBER CORRADINI: I can lend you my CD.

MEMBER BANERJEE: Please. Just this part of the CD.

MS. CUBBAGE: There was some discussion earlier on hydrogen water chemistry. I'd just like to reiterate the Staff's position that current regulations do not require applicants to implement hydrogen water chemistry. I will note that the first two COL applications referencing the ESBWR design certification have selected hydrogen water chemistry. We don't see any significant safety issues with treating hydrogen water chemistry as an option to any future applicant because of the selection materials. They're resistant to degradation. They also, a key point is the in-service inspection required by the ASME code and that's all I plan to present on that.

MEMBER CORRADINI: But under NUREG 03-13, wouldn't you have still have augmented inspection if you didn't have hydrogen water chemistry, because you wouldn't have two means of mitigation?

MS. CUBBAGE: We have Gregory Makar from the Staff here.

MR. MAKAR: Hi. I'm from the Division of Engineering, Component Integrity. Yes. That's true. Our approach -- our safety concern in this area is the leakage and structural integrity of the reactor coolant pressure boundary. And our regulatory approach here is the design and fabrication of the reactor coolant pressure boundary and then we have -- in order to prevent rapid or sudden types of degradation and inspection requirements are key to that.

With respect to the reactor coolant, we agree that with -- in terms of stress corrosion cracking which is the concern here, that these -- this combination of materials and the environment and the stresses could create -- is susceptible to stress corrosion cracking. And that we probably cannot pull that, pull those -- that intersection apart completely. And even going to hydrogen water chemistry, it's not an on-off switch for stress corrosion cracking. It is -- it's an engineer -- it may represent an engineering threshold that allows us to go to longer times, feeling that we can't have stress corrosion cracking. But really with respect to our safety concern, that trying to optimize the materials and the augmented inspections and the code required inspections are adequate to ensure that integrity.

MEMBER BANERJEE: Let me ask a question about the mixing of the hydrogen. This is a natural circulation system, so if I recall, at some plants there was a problem with how well the hydrogen mixed in the downcomer, right, the feedwater injection and stuff.

Are there any issues related to that which occur in this system? I remember this occurred in Forshmark and they asked me to evaluate how well it mixed at one point. But does this happen in this plant, the velocities are somewhat lower, I imagine. Are there mixing issues?

MR. MAKAR: I'm sorry. I don't know the answer to that.

MEMBER BANERJEE: How do they inject it?

MR. CAINE: This is Tom Caine from GEH. It's injected in the feedwater and the example you mentioned in the Swedish plant was really due to the configuration of the feedwater sparger not getting a full azimuthal distribution out into the reactor annulus. My understanding is that the ESBWR is going to have that good azimuthal distribution so that shouldn't be an issue.

The feedwater is a pumped-driven system so getting the feedwater into the downcomer flow should be very similar to what happens today in the operating plants.

MEMBER BANERJEE: Thank you. That deals with it.

MEMBER ARMIJO: I would just like to make one point. I agree with Amy's points that it's not a regulatory requirement, but I do disagree with the point that the ESBWR Class 1 and 2 materials are resistant to stress corrosion, cracking, degradation.

They may be better than 304 or 304L, but they're not immune. And a lot of testing, as well as plant experience has shown even the 360 nuclear grades can crack and have cracked in European plants, have cracked in Japanese plants. And so that's just factually wrong. That's just one element of protection against stress corrosion, cracking. They are better materials, but they're not immune. The fabrication can undermine their immunity. Poor fabrication can cause good material to be susceptible.

So again, I'm glad that the plants that are looking seriously as ESBWRs are selecting hydrogen water chemistry because then they have the benefits of better materials, better fabrication, and good water chemistry. That combination, I think, offers the potential for a crack-free operation of these plants with later benefits on inspection and everything else.

Finding and fixing cracks is a very poor substitute to picking the right materials, the right water chemistry and fabricating them properly. So I'm glad that the actual operators that are looking at this system are selecting this kind of water chemistry and in time I would hope that the regulatory body pushes that, even though you legally may not be able to do it. I don't know.

MS. CUBBAGE: I understand what you're saying and Bob Davis is at the mic here.

MR. DAVIS: I'm Bob Davis, and I'm the Senior Materials Engineer that reviewed a lot of the reactor coolant pressure boundary. And I just want to note that NUREG 03-13 provides recommendations for material selection, augmented inspections. This all came out of the early BWR stuff. The materials that GE is using are considered category A material. They don't require -- they're not considered category A if they hydrogen water chemistry. They're considered category A materials. They don't require any augmented inspections --

MEMBER ARMIJO: I thought you had to have two.

MR. DAVIS: In the NUREG, what's category A though, but not in category A.

MEMBER ARMIJO: I'm not too worried about categories. I'm worried about physical resistance to stress corrosion, cracking, and real conditions, not what some category says. The testing data is out there in the literature and the operational experience in power plants is out there in the literature. I think you're doing a disservice to your clients by giving the impression that these materials, by themselves are perfectly adequate. All you have to do is wait around until they crack and then you find them and fix them.

That's not the way to field the brand new design that has a potential of being basically immune from these problems if you take advantage of all the tricks you've learned over the past 40 years.

MEMBER CORRADINI: Just to move on, I think you see Sam's point for the first bullet or the sub-bullet and it seemed a bit smudged. But I think we need to go on --

MR. MAKAR: I agree. The staff agrees with his comments on that and we intentionally did not use the word immunity because we do not believe that these -- and they may not be immune in hydrogen water chemistry to irradiation-assisted stress corrosion, cracking and it may give a false sense of security to --

MEMBER ARMIJO: Right, but you've got to agree that the combination of three independent mechanisms to minimize risk is much, much more powerful than any one by itself.

MS. CUBBAGE: But we have assured ourselves that the safety issues are resolved and that the regulations are met.

Craig Harbuck from Tech. Specs.

MR. HARBUCK: My name is Craig Harbuck. I'm in the Technical Specifications Branch in the Division of Construction, Inspection Programs. And I understand you were wanting to talk about passive ECCS and containment cooling surveillance requirements and their frequencies.

We touched on it earlier in the GE presentation. The systems that we're going to talk about as it comes up are the Automatic Depressurization System, the Gravity-Driven Cooling System, the Isolation Condenser System, Passive Containment Cooling System, and associated with those are the EC/PCC Pools and I inadvertently left off the Standby Liquid Control System.

We believe that the testing that's specified in the technical specifications for these systems is consistent with what testing is done on similar-type components and operating plants. It's consistent with the standard tech specs. And it's mostly based -- there are other considerations, but engineering judgment being a consideration for frequencies, and to facilitate discussing these, there's four slides that list by focusing on the frequency what the various tests are and the very general language and what systems they apply to.

Another thing to point out is that many of the components in these systems are also subject, particularly valves, are subject to in-service testing and so we can talk through in-service testing also. But in particular, squib valve testing is included. The ICS return line valve testing, ICS system initiates by opening a couple of nitrogen motor-operated valves. And those valves have to be struck tested quarterly. And then GDCS injection line check valves are by virtue of test connections on the injection lines are able to operate the check valves to verify they function properly. But that comes under the in-service testing.

There was some discussion earlier about the non-condensable gas venting. The only thing I'd like to point out there, other than the GDCS lines is that the isolation condenser system and PCCS condensers all have provisions for either automatically or upon actuation venting of any noncondensables that might occur as part of the design. And all that venting is done to the suppression pool.

And the last --

MEMBER CORRADINI: Where is the venting done from? Maybe I forgot.

MR. HARBUCK: Well, there is -- the ICS system has vents from both the high and low parts. And in the PCCS, I believe the venting is from the lower drum.

MEMBER CORRADINI: Lower drum into the wet well?

MR. HARBUCK: Yes, the connection -- well, no. The lower drum of the condenser and then the water drains through the GDCS pool and the gas vents to the suppression pool.

MEMBER CORRADINI: But when you got to the vent -- I guess maybe -- when you said venting, I thought you were talking about not during operation, but during to clear it. So I seem to remember this is a small point. We can talk about it in a side question. I just wanted to understand for venting where it was done. So let's just move on.

MR. HARBUCK: All the venting goes to the suppression pool.

MEMBER CORRADINI: Okay.

MR. HARBUCK: And then this other issue, resolution of bracketed items, we had a question early on in the review about to clarify what was meant by bracketed information in the tech specs and in the bases. And there was response that was implemented in Revision 3 which indicated that items that were in square brackets would be items that might be contenders for COL information items.

And if they were curly brackets it would be stuff that was to be settled during the design certification. Well, in Rev. 4 that changed and there was this shift in using curly brackets to also mean items that potentially could go to -- be completed by a license holder and so we've had some discussions about that and where we're --

MEMBER SIEBER: You should have used this kind.

MR. HARBUCK: Where we're going on this is that we would just use the square brackets. We would use the square bracket for both kinds of information, whether it would be provided during the COL application review or after the license was issued and then in the tech specs we would have reviewers' notes which would explain how the brackets would be -- how they would be resolved or how -- what the applicant or the licensee had to do to resolve the provided information.

And those brackets that are for the COL applicant, we would prefer that they actually put something in the brackets, not have a set of brackets in empty white space. And holder items, license holder items indicated by brackets would need to be tied to design acceptance criteria.

An example would be instrumentation settings tied to instrumentation system design, detail design.

So just looking at this list, the frequencies that you see are fairly typical for what we would find in comparable systems in the --

MR. NAMARA: This is Mike Namara from the

Branch for Tech Spec. and I just want to clarify that the bracketed item issue is still an open issue between the Staff and GEH with regards to which items might be going forward as COL holder items or going forward as COL applicant items.

The preference of the Staff would be to resolve or have most of these addressed on the design certification stage.

MEMBER CORRADINI: I'm going to let you guys sort out the bracket stuff.

(Laughter.)

MEMBER SIEBER: When we are all done, there won't be any.

MS. CUBBAGE: It's what gets filled in when. If it's part of the certification and part of issuance of the license or something that needs to be filled in after they've constructed the plant and the equipment, and finished the design of the instrumentation and pick set points.

MR. HARBUCK: On the first slide of this four slide set, I just would add that the standby electric control system for a 24-hour frequency also has for the accumulators which are pressurized to check the volume, temperature, and pressure in a 31-

day frequency to check concentration of the solution.

MEMBER CORRADINI: So remind me, the second one, and maybe I just don't understand the -- so every day RPV --

MR. HARBUCK: I need a little more explanation for that one.

I didn't distinguish between operating modes and shutdown modes, but the second -- that second one is for shutdown modes.

MEMBER CORRADINI: Thank you.

MR. HARBUCK: To make sure your mode 5 or beginning mode 6, you -- if you have some reason -- you've lost decay heat removal and the GCS needs to inject, you've got a vent path.

MEMBER CORRADINI: Thank you.

MR. HARBUCK: And then the pool inventory you see is repeated, but the second one is for shutdown situation.

MEMBER CORRADINI: Thank you.

MR. HARBUCK: And then on the next page there's also a standby electric control system, the valve position verification and the squib firing circuit continuity check.

On the last one on the second page, the

automatic valve actuation, this typically doesn't involve actually -- changing the valve position, you test everything but the valve position.

MEMBER CORRADINI: We're doing fine.

MS. CUBBAGE: We're on 13 still?

MR. HARBUCK: I'm on 15.

MS. CUBBAGE: Fifteen.

MR. HARBUCK: Fifteen.

MEMBER CORRADINI: Before you go to 15, can we talk about 14 for a minute?

MR. HARBUCK: Sure.

MEMBER CORRADINI: So 24 months, verify valve locked open. I understand that.

Twenty-four months, SRV Manual Actuation. So you would go through on the non-squib SRVs and cycle them on that frequency. So all would be cycled within on a two-year basis. Do I understand that correctly?

MR. HARBUCK: Which one are you looking at?

MEMBER CORRADINI: Page 14, second one.

MR. HARBUCK: The second one.

MEMBER CORRADINI: GEH can correct. I've got them.

MR. HARBUCK: You mean page 16?

MEMBER CORRADINI: Yes.

MR. HARBUCK: Okay, what this is is that there's four solenoids on each valve.

MEMBER CORRADINI: That page, second line.

MR. HARBUCK: Right. And there's four solenoids in each valve, so every 24 months they cycle all the valves, but using one of the solenoids and they move through the different solenoids to actuate. I was confused. That should be 96 months to indicate the total time between testing each solenoid because there's three from the normal actuation system and then there's a diverse actuation system which is the fourth solenoid.

MEMBER CORRADINI: Thank you. And the verify drain lines to GDCS pool.

MR. HARBUCK: The GDCS system has no valves in it. It's a straight shot from the dry well through the tubes and back down to the -- draining back down to the GDCS. And there's also a vent line to the suppression pool. So there's a requirement -- and there's six of these condensers. So you check one every outage so that would be 12 years between this and it's basically just verifying there's no obstruction.

MEMBER CORRADINI: Just to go back to GEH, you already said the GDCS pool line is six inches. The vent lines and suppression pool and flow path through condenser -- what are those lines again? I have forgotten and I apologize.

MR. UPTON: This is Hugh Upton with GEH. The PCCS vent line is a 10-inch vent line and this is what we're talking about is the vent line coming from the PCCS heat exchanger to the suppression pool.

MEMBER CORRADINI: To the suppression pool. And then -- okay, thank you very much.

MR. HARBUCK: The last page, you'll see the isolation condenser heat capacity verification. There's four condensers. There's four condensers on staggered test bases. You do one -- each one gets tested every eight years.

And then the 10-year, the verify flow paths unobstructed. We discussed that one earlier and then this 10 year on the verify vent path from the pools unobstructed. This is the path where the water evaporating to exit the --

MEMBER ARMIJO: Are those verifications

very difficult to perform?

MR. HARBUCK: There is a number of ways you can do the verifications. I would have to defer to GE to offer an explanation or more description about that.

MEMBER ARMIJO: Somebody just tell me. Is it every 10 years? Because it's very difficult to perform or it's every 10 years because that's the general practice on things like this?

MR. HARBUCK: Again --

MEMBER ARMIJO: But if it was easy to perform would you do it more often?

MR. HARBUCK: Not necessarily.

MEMBER BANERJEE: Are these empty lines basically?

MR. HARBUCK: For the ECCS line, they're basically empty, except for a sealed line down in the --

MEMBER CORRADINI: So let me be provocative to get an answer out of GEH. So if you're doing everything else in two years, why are you waiting ten years for this one? That's where I thought Sam was going with it.

Is it a matter of difficulty? What it

isa matter of because you're changing the inspection frequency of a factor of five with two different sets of lines.

MR. WILLIAMSON: Dan Williamson, GEH. I lost track of exactly which one we're talking about.

MEMBER CORRADINI: We're looking at page 14 and page 15. And page 14 if I understand it, you're verifying drain lines to the GDCS unobstructed and line suppression pool every two years. And on page 15, you're verifying flow paths unobstructed like the GDCS I assume to the vessel and from pools unobstructed every ten years. And so Sam's first question was how hard is it? And then next follow-on question will be so if it ain't so hard, why are you doing it five times longer?

MR. WILLIAMSON: The frequency, in fact, the 24-month frequency is staggered for each PCCC, so it's essentially you do one of them every two years. You repeat that same one 12 years.

MEMBER CORRADINI: Okay.

MR. WILLIAMSON: It's very similar to the 10-year frequency.

MEMBER CORRADINI: Okay.

MEMBER BANERJEE: How do you do this?

MS. CUBBAGE: Which one?

MEMBER BANERJEE: Verify the line is unobstructed.

MR. HARBUCK: there is in-service testing, there's pressure testing.

MEMBER BANERJEE: Is it a flow rate that you look at? How do you know it's unobstructed. The word unobstructed is interesting.

MR. HARBUCK: I would have to defer to GE as exactly how it's done, but I suppose it would have to be some --

MEMBER CORRADINI: So let me just take an extreme case. I'm wondering where Sanjoy is going, but my extreme case is the oil company sends down a little beastie that goes and looks at it.

MEMBER BANERJEE: It's a pig.

MEMBER CORRADINI: I couldn't remember what it was called, a pig. So my question is what's your equivalent of a pig to determine it's unobstructed?

MEMBER BANERJEE: And they have smart pigs as well.

MEMBER CORRADINI: They're smart pigs. They're not stupid pigs, that's true.

MS. CUBBAGE: Other than firing off the squib valve and --

MEMBER CORRADINI: I am sorry to be so -- this is -- you're kind of back to the overall thing that we're just kind of mulling over about checking passive systems.

MR. DEAVER: This is Jerry Deaver with GEH. There's any number of ways that could be used. What we're suggesting right is that flowing of the lines is one way possibly; flushing visual inspection, what might include a bore scope kind of inspection which would be sending small cameras down the line to take a look.

A lot of it depends on geometry and in some cases that would be very difficult.

MEMBER BLEY: You have not decided yet how you're going to recommend this be done?

MR. DEAVER: We haven't really gotten into all the specifics, but obviously, as we design the actual pipe runs and so forth, we need to keep this under consideration.

MEMBER BLEY: Okay.

MEMBER CORRADINI: That helps. So we'll be talking. Thank you.

MR. HARBUCK: Is there anything else that you want to ask about either the surveillance or the in-service testing?

Conclusions. First one I believe I've already mentioned. And we're pretty -- we've concluded that what's been proposed is acceptable for ensuring we're meeting the LCOs. And then the next slide is a repeat from the previous presentation, but we've got a number of issues remaining at this time and so we haven't reached an overall conclusion about the acceptability of the tech specs. We also are dependent upon what happens in other chapters for so many of our issues.

That's it for me.

MS. CUBBAGE: And that overall conclusion does apply across the board to these chapters. They all do have some degree of open items. We'll be presenting to the Committee at the end stage, when we have a final safety evaluation. It addresses all of the open items. We'll brief that to the Subcommittee and then to the full Committee.

MEMBER CORRADINI: Are there questions by the Members?

MEMBER BLEY: Yes. Amy, this isn't an

instrument air question, but I'm going to pull on a thread that came from there. I'd like to understand the process you folks use when a new DCD revision comes out and it was that cartoon issue that comes to mind to look at new drawings that are issued for systems and if there's anything different that isn't fully explained in the text, does that generate a question back about why this change and what does it affect?

MS. CUBBAGE: In this particular case the system did change between Rev. 3 and Rev. 4.

MEMBER BLEY: No, but I mean in general.

MS. CUBBAGE: In general --

MEMBER BLEY: When the new rev. comes out does somebody compare these and say oh, this is a little different.

MS. CUBBAGE: Yes.

MEMBER BLEY: Why is it?

MS. CUBBAGE: We do look at the new DCD revisions in detail. We ensure that it has not invalidated any of the conclusions that we had drawn previously and we'll base our conclusions in the final DCD revision that comes in.

MEMBER BLEY: So for every system you're

looking at, you do those.

MS. CUBBAGE: That's right. To facilitate that, GE has been providing us with the document that shows the changes between one rev. and the next rev.

MEMBER CORRADINI: So there's a tracked change.

MS. CUBBAGE: We don't have to go word by word, but again that is our responsibility to ensure that the SED is acceptable at the end.

MEMBER CORRADINI: So there's some sort of track changes.

MR. HARBUCK: They provide a change list.

MEMBER CORRADINI: Ah.

MR. HARBUCK: And there's usually an explanation of why the change and oftentimes it's related to our questions.

MEMBER CORRADINI: Okay.

MEMBER BLEY: In the second -- I had two. They both came from the same source. I appreciated the discussion on the instrument air problems and the insights that were there in the staff, but listening to the interplay on all these systems, is there a place or a process that that kind of knowledge of operating experience comes -- where does that come into this review to make sure that the reviews conducted by individuals who might not be so familiar with that are taking those things into consideration, as least to the extent it's important?

MS. CUBBAGE: As John Sigala indicated, we do periodically assess our Standard Review Plan as we did this about a year ago now and when we do that, we factor in any experience that has happened since the last SRP updates.

MEMBER CORRADINI: So it's through the SRP.

MS. CUBBAGE: Through the SRP and in the interim the Staff also has an obligation to look at all of the Generic Letters, bulletins, generic safety issues, etcetera, that have been issued by the Staff to ensure that they've been properly incorporated by the applicant into their design.

And you will be seeing at the final SER stage in our Chapter 20, we will have a listing of all the Generic Letters and bulletins and other generic issues that the Staff looked at and it will show where in the staff's evaluation that it has been addressed.

MEMBER CORRADINI: I appreciate that.

MEMBER BANERJEE: I just have a question about the equalization line. This was back to the presentation actually, I'm sorry.

Do you have a procedure to verify that the equalization line is unobstructed?

MS. CUBBAGE: The equalization line --

MR. HARBUCK: It's included in the surveillance requirement to verify the lines are unobstructed.

MS. CUBBAGE: It's part of the GDCS spec.

MEMBER BANERJEE: It's part of the GDCS spec.

MR. HARBUCK: Right.

MEMBER BANERJEE: And the condensate drain line is part of the --

MS. CUBBAGE: The condensate drain line for the isolation condenser? That would be part of the isolation condenser.

MEMBER BANERJEE: So there is a procedure in place to validate those are unobstructed.

MR. HARBUCK: Well, every two years you operate the ICS condenser so you verify performance of the whole.

MEMBER BANERJEE: How about the equalization line? How do you look at that?

That's quite a trick, I would think.

MS. CUBBAGE: They would look at the GDCS objection line.

MEMBER BANERJEE: Okay. Unspecified as yet.

MEMBER ABDEL-KHALIK: Mr. Chairman, I'd like to express my personal concern regarding the process by which this piecemeal chapter by chapter review is being conducted. The time line of scheduled pressure which has necessitated the use of this piecemeal process are no different, in my view, than plant operators whose culture emphasizes production over safety.

Such a culture causes the applicant to continually justify minimum standards and present incomplete analyses, rather than perform and present high quality complete analyses that withstand the scrutiny of a thorough review.

I hope that at the end of the process we will have the opportunity to review this application in total rather than a piecemeal, incomplete, inadequate fashion.

Thank you.

MS. CUBBAGE: I appreciate your comment and I'd just like to point out that we've taken this approach in order to engage the Committee early and receive early feedback, not in any way to try and rush this review or to address any schedule pressures.

We will be coming to the Committee with a comprehensive complete safety evaluation at the end of the process.

MEMBER CORRADINI: Can I just clarify? Said, your point is that you would rather have seen it with all the RAIs settled and looked at the complete product.

MS. CUBBAGE: The concern on our part with doing that would be that an issue might be raised by the Committee because you certainly all raised very good questions and the opportunity to address them at the end is much more challenging when the design is at a much later stage. There's more opportunity for your issues to be addressed at this stage. It certainly doesn't preclude you from raising issues later.

MEMBER ABDEL-KHALIK: But when an issue

is raised I think it would be much more beneficial if we revisit that particular issue after the applicant has responded to the RAIs and the appropriate analyses had been completed.

MEMBER MAYNARD: I don't think we're being asked to approve these chapters. What we're really being asked to do is to make sure we have the right issues that are being addressed. If there's any more to be carried out, but we're not being asked to approve anything at this point.

MS. CUBBAGE: You're absolutely right. We're looking for that early feedback and education from the Committee that if you have any issues that are not -- were not engaged in GE-Hitachi on at this time we'd like to know about those that we can address them. We're looking for the Committee's final approval at the end when we have a final safety evaluation.

MR. SHUABI: Let me add to that. This is Mohammed Shuabi of the Staff. We had a decision to make about a year ago and the decision was do we want to wait another year, two years, three years before we start engaging the Committee on the design certification at the point to where maybe we would be

-- where you want us to be.

We felt that it would not be in our best interest to wait until then to come and start briefing you on what we're doing in this. We wanted to come here and present these chapters, present to you what we're doing, present to you the open items that we've identified and we're coming and telling you that these are the open items that we, the Staff, are pursuing. And if you have any additional open items, we're looking to get that into our review process so that we can address that. And you've had your questions and we've taken those back and we've actually asked RAIs as a result of these interactions and I actually think it's been a very good way to do it.

The challenge, I think, and maybe at least a little bit of frustration is sometimes we have to say this topic or that topic, it's addressed in a different chapter and then you come back with comments about well, how do these link together? I think when we come back to you at the final NCR stage and we have the whole consolidated safety evaluation, you might be able to see how the whole thing fits together. But at this point in time, I did not want to wait. We did not want to wait another year, two years, before we're here for the first time talking to you about what we're doing, how we're doing this, what issues we're raising and to get your insights and your input.

So we valued interactions with you early in the process so that we can get your input and I hope that that was beneficial to you. It was beneficial to us. And we really did take your comments back and we're trying to address the ones that we believe need to be addressed.

MEMBER ABDEL-KHALIK: I think it's just a matter of balance as to where the appropriate point, especially when issues are revisited.

MR. SHUABI: We agree.

MS. CUBBAGE: There's an efficiency issue and we didn't want to waste your time. We feel at this point that it's beneficial to hear any of your comments and concerns as early as possible.

MR. SHUABI: We really did think hard about this and we consulted with the ACRS Members and staffers to make sure that this is a workable process and we said we want to try this. So we're trying it.

I guess I'll defer to the Committee in

terms of whether they'd like to stop and for us to do it differently.

MEMBER CORRADINI: Well, I think we'll probably have to discuss this. I wouldn't say we're going to stop talking about this point, but we can stop at this moment about this. I think we're going to come back to it. I think the first interim letter specifically was crafted so that we didn't commit to anything, but we raised concerns. And I think if there is a second letter, it will be crafted similarly.

MS. CUBBAGE: And we understand that and that was the expectation.

MEMBER CORRADINI: We see where the Staff is coming from on this. I appreciate them giving us a heads up and I also appreciate GEH for the same things.

MEMBER SIEBER: I think the design is more flexible. As more time goes on, the less flexible it becomes and therefore things, our concerns that are raised now are far more easily addressed than they would after General Electric does a lot more engineering work and it becomes financially prohibitive to make major changes.

So I think there is an advantage doing a pre-review like we're doing as long as we get the opportunity in the end, the entire GCD application.

MR. KINSEY: This is Jim Kinsey from GEH. I guess I'd just like to echo that same position. We were trying this based on dialogue with the ACRS early on and with the NRC staff. We're trying a new and different process here, working to get your inputs and issues on the table early. Again, we can accommodate a more comprehensive and succinct resolution to many of those issues, the earlier in the process we're aware of them. And we recognize that that brings some frustrations with it and it takes a lot of resource to do these Subcommittee and follow-up full Committee meetings, but it's been very, very valuable to us at GEH and I think the process is working. Again, it takes some level of effort, but it's been very beneficial to us as we proceed through the remainder of the design certification process.

And as Amy mentioned, we do plan to or will be required to come back around with the full SE at the back end of the process and hopefully we'll have addressed all of your issues and concerns at that point, but we're certainly willing to listen to any new or different ones that may be identified at that time.

MS. CUBBAGE: And one last note to just put in perspective where the Staff is at in the process.

We had issued a total, at this point of just over 3,700 RAIs. At this point, 2,800 are resolved, so that's three-quarters. And so I think the timing is such that we do have a lot of issues that have been resolved.

MEMBER BANERJEE: When do we see the final SER?

MS. CUBBAGE: The final SER, we're actually currently reassessing the schedule for that and I would estimate that it won't be in this calendar year.

MEMBER BANERJEE: It will be?

MS. CUBBAGE: Will not.

MEMBER CORRADINI: You won't get a Christmas present.

MS. CUBBAGE: You won't be getting a Christmas present, but we will be following up with your -- the ACRS Staff to make sure those interactions are scheduled.

MEMBER CORRADINI: We can discuss that, I think in the context of when we start -- when we discuss the letter because you're going to hear about potential outgoing meetings and how to schedule that.

MS. CUBBAGE: Right, our near-term concern would be scheduling the next Subcommittee meetings on the SER with open items. We do have a couple of chapters to finish before we're completed with this SER with open items cycle.

MEMBER ARMIJO: When will we see the final DCD?

MS. CUBBAGE: GE-Hitachi is going to be submitting a revision to the DCD, DCD Revision 5 at the end of May and their intent is that that would be the final rev. that we're basing our SER on. And of course, the staff would need to review that rev. and come to that conclusion.

MEMBER SIEBER: They would like that.

MS. CUBBAGE: They would like that. It will be here at the end of May.

MEMBER CORRADINI: Mr. Chairman, on time, and on budget. Back to you.

CHAIRMAN SHACK: On time.

MEMBER CORRADINI: This is the new world. I can spin it any way you want.

(Laughter.)

CHAIRMAN SHACK: We'll take a 15-minute break and then we'll teach Professor Corradini how to tell time.

(Laughter.)

(Whereupon, at 3:42 p.m., the meeting was concluded.)