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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

September 5, 2007

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

SUBCOMMITTEE ON PLANT LICENSE RENEWALS

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WEDNESDAY,

SEPTEMBER 5, 2007

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

MEMBERS PRESENT:

MARIO V. BONACA Chairman

GRAHAM B. WALLISMember

WILLIAM J. SHACKMember

SAID ABDEL-SHALIKMember

J. SAM ARMIJO Member

OTTO L. MAYNARD Member

NRC STAFF PRESENT:

TOMMY LE
ROY MATTHEW
GLENN MEYER
KEN CHAN
BARRY ELLIOT
AMBROSE LOIS
JIM MEDOFF
RICHARD CONTE
BILL ROGERS

ALSO PRESENT:

GARRY YOUNG
ALAN COX
STEVE BONO
JOHN McCANN
BRIAN FINN
JOE PECHACEK
MICHAEL STROUD
BRIAN FORD
TOM MOSKALYK
GEORGE RORKE
LARRY LEITER
ARTIE SMITH (via telephone)

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

10:28 a.m.

CHAIRMAN BONACA: The meeting will now come to order. This is a meeting of the License Renewal Subcommittee. I'm Mario Bonaca, Chairman of the License Renewal Subcommittee. The ACRS members in attendance are Graham Wallis, Sam Armijo, Said Abdel-Khalik, Bill Shack, and Otto Maynard. John Barton is also attending as a consultant for the Subcommittee. Gary Hammer of the ACRS staff is the designated federal official for this meeting.

The purpose of this meeting is to discuss the FitzPatrick license renewal application. We will hear presentations from Entergy Nuclear, NRC Office of Nuclear Regulatory Regulation, Reactor Regulation, and Region I. The committee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions as appropriate for the deliberation of the full committee.

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register. We have received no written comments or requests for time to make an oral statement from any member of the public regarding today's meeting.

A transcript of the meeting is being kept and will be made available, as stated in the Federal Register notice. Therefore, we request the participants in this meeting use the microphones located throughout the meeting room when addressing the Subcommittee.

The participants should first identify themselves and speak with sufficient clarity and volume so that they can be readily heard. We will now proceed with the meeting and I call upon Dr. Kuo of the Office of Nuclear Regulation to begin.

DR. KUO: Thank you, Dr. Bonaca, and good morning to all members. I am P.T. Kuo, the Director of Division of License Renewal. Sitting to my right is Tommy Le who is the project manager for the staff's review. To my extreme right is Glenn Meyer who is the inspection team leader from Region I.

We also have several people from -- one person from Region, Rich Conte, who is the branch chief in Region I, and Raj Aruk who is the branch chief here in the headquarters responsible for this review, and Ken Chan who is the branch chief for the audit team. We also have other technical reviewers sitting in the audience and ready and prepared to answer any questions members may have.

Briefly, this Safety Evaluation with open items from you has two open items. One is in regard to the fluence level and there are several sub items or sub questions with them because it all depends on the fluence level. Then the other open item is the fatigue evaluation. Actually, I'm going to talk about the fatigue in more general terms. I just wonder whether it is better to do now or perhaps before the staff makes our presentation. I can go either way. I can talk about it now.

CHAIRMAN BONACA: Talk about it now.

DR. KUO: Talk about it now?

CHAIRMAN BONACA: Maybe then the licensee may have some comments after the presentation.

DR. KUO: Okay.

CHAIRMAN BONACA: But it's up to you. I mean, whatever is more convenient.

DR. KUO: I can do either way.

CHAIRMAN BONACA: Now.

DR. KUO: Do it now. Okay. Just by way of background, we do fatigue evaluation for Class 1 components. That includes the piping and other metal components. For the newer plants most of them that have used the ASME code, Section 3 provisions. For older plants such as FitzPatrick and some other plants, some of the components were designed to NCP 131.1 standard.

Our issue here with the fatigue evaluation is that based on the research done in the late '80s and early '90s the people have identified that the fatigue curve is affected by the environment it's in. Section 3 code has the fatigue curve which basically is based on testing data in the air.

The components we have in the nuclear power plants are mostly in the reactor water involvement so it makes the difference and then we call the involvement a correction factor F sub EN. That's the question on the table with our fatigue analysis.

We had GSI 166 some years ago and the subject was fatigue. We had a contractor at the national lab who did the evaluation for us and the conclusion of that research result was that for most part the ASME code kind of design is good for 40 years. There may be some leakage that will occur but from the safety perspective for 40 years we do not have any problems.

It identifies six critical locations that they evaluated and it appears that the cumulative uses factors were okay. However, it made the conclusion that for a life of 60 years the staff should look at the effect of environment to the pipe or components. We created another GSI 190. After more than a year or so of research the GSI 190 was closed with the conclusion that based on the risk perspective it may leak but there won't be any safety concerns.

However, the report recommended that the staff would review several critical locations which is UF-high including the involvement of correction. We took the NUREG-6160 that was done at the end of the GSI-166 that identified six critical locations. After the close of GSI-190 the recommendation was the staff should have the evaluation of the six critical locations considering the involvement effects. That is what we have been trying to implement in the license renewal review.

Plant specific considerations for this particular SER we had the open items on fatigue. The reason is the Part 50 rule is a requirement to address the Part 54.21(c)(1). It gives three options for fatigue consideration. The first option was that the applicant is able to identify that the original analysis remain valid. That's the first option.

The second option says the analyses had been projected to the end of 60 years. They do the analysis and they were able to project the validity of their analysis to the 60 years. The verb the rule uses is "have been project."

Then the third option is if the applicant doesn't do either one or two, the first or second options, then do the third option which is an option that the applicant would provide an Aging Management Program that manages the aging effect throughout the extra 20 years.

MEMBER WALLIS: Can I ask you a question, P.T.?

DR. KUO: Yes, sir.

MEMBER WALLIS: On this fatigue matter, it seems to be all calculation. Is there any evidence of what the fatigue effects are? Are there any experiments or inspections that show any fatigue effect?

DR. KUO: Well, the use of the licensees, I believe, have this cycle counting kind of programs there. They use that to confirm that the original design was all calculations. Whether we have identified any cracks, for instance, due to fatigue or not I don't know. Someone has to help me.

Ken, do you know?

MR. CHAN: My name us Ken Chan. I'm the

branch chief for License Renewal Branch C which conduct all the audit. P.T. just mentioned that every applicant has a cycle counting either manually or automatic. In terms of experiments that Dr. Wallis mentioned, in the early stage when our national lab consultants help us to develop the so-called environmental adjusted fatigue CUF developed the FEN.

In those days they pour all the experimental data or all the extra monitoring data into the play to develop those factors. They vary one parameter for a range and another parameter for a range. Those experiments I included in original development of the FEN. Those factors also being used by the ASME code. Instead of trying to develop factors they are trying to develop curves. The curve is more definite. If you put a curve into the code, you have to go through so many cycles of review. So far the ASME code fatigue strength committee has not come to a conclusion what is the best curve to use.

They openly say since those FEN factors were developed mainly for license renewal and has been used for license renewal successfully, they say they don't object for license renewal to continue to use FEN. For the other kind of reactors like new reactors they expect them to use different technique, waiting for the new development of the curves. I don't know when it will be coming up.

MEMBER WALLIS: These experiments you mentioned, these are experiments on fatigue testing?

MR. CHAN: Some are fatigue testing.

MEMBER WALLIS: But they are not measurements in plants. I just wonder if there is any evidence of fatigue in these actual plants or is it all just a theoretical calculation that everything is based on?

DR. KUO: That's the reason I say I don't know if there's any actual identification of fatigue crack, for instance, from any plant. I don't have that knowledge. However, as Dr. Chan just mentioned --

MEMBER WALLIS: Maybe we'll get into this later when they are up to 87 percent of the usage factor or something. Does that mean they are getting close to a limit or is there a huge conservative factor on top of that?

DR. KUO: With regard to those when you see that the definition of UF is equal to one is that it is just initiation of indication. It is not the actual crack.

MEMBER WALLIS: Very conservative.

CHAIRMAN BONACA: The other thing at least I've seen is that when they count the number of cycles and project them based on past cycles, that is a huge margin oftentimes. The number of cycles is well below the allowable cycles.

MEMBER WALLIS: Maybe we'll get into this later.

MEMBER ARMIJO: But there have been instances of fatigue failures in power plants. Usually high cycle and thermal sleeve.

MR. CHAN: If I may add just one small point. In the recent audits we have started to ask the applicants to provide a so-called alarm limit. Before reaching the limit of one we want them to define what is your alarm limit. .89, is that big enough to become the alarm limit?

After .89 how many fuel cycles the component will be able to sustain without affecting the functionality of the plant. Those are being gradually put in and now it's almost a requirement to give alarm limit. You don't just say, "You hit one, you fail." Way before you hit one. For how long you identify you need to watch, you need to exercise Aging Management Program. That is being applied to the latest plants that we are auditing and reviewing.

CHAIRMAN BONACA: Okay. And we'll hear from both the licensee and then, of course, the staff.

DR. KUO: Later on if there are any other questions, I will try to answer.

MEMBER SHACK: P.T., what I'm confused about is why is this plant different than the other plants? I mean, you've had this in place since license renewal began.

DR. KUO: There is no difference from other plants. Like I said, the rule requires that if they don't use Aging Management Program, they have to demonstrate either that the current analyses will remain valid for the next 20 years or they do re-analysis to try to demonstrate that they are good projected to 60 years.

CHAIRMAN BONACA: Including environmental effects.

DR. KUO: Including environmental effects.

MR. BARTON: What you're saying is all the other B31 ones that we've done to date have all satisfied that requirement?

DR. KUO: I wouldn't say all but based on our search I would say all but two. For whatever the reasons there, I don't know yet, but for the past review that we have done all but two have all demonstrate by the one or the other.

CHAIRMAN BONACA: I'm surprised by two because we have always looked at this issue of GSI 190 for all the applications we have reviewed which is all of them.

MEMBER SHACK: When I look back at Tobin, which is where this thing seemed to have started, there's this Commitment 31 and Commitment 35 and there's a change in wording here. You have now changed your standard for what is an acceptable commitment?

DR. KUO: No. That is why I mentioned the rule language. The verb there is "have been projected to." If you do the analysis it has been completed.

MEMBER SHACK: Oh, I see. Okay. You can't say you are going to do the analysis.

MR. BARTON: You have to say completed the analysis. Okay. All right. Got it.

MEMBER SHACK: And they have it.

MR. BARTON: And they have it. That's right.

DR. KUO: If there's no further questions, then I turn the presentation over.

CHAIRMAN BONACA: Please.

MR. BONO: Mr. Chairman, ACRS members,

good morning. Thank you for allowing us to make this presentation. I would like to begin by introducing the FitzPatrick staff that we have in attendance today. My name is Steve Bono. I'm the engineering director at the facility.

To my left is Joe Pechacek. He is our programs and components manager. To my right is Alan Cox. He's a member of our License Renewal Project Management staff. He's a senior manager of the Project Renewal Staff. To his right is Garry Young who heads up our project group that runs the License Renewal Projects. I would also like the other members of the FitzPatrick staff to introduce themselves at the back table.

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

MR. FINN: I'm Brian Finn, director of Safety Assurance at FitzPatrick.

MR. FORD: Brian Ford. I'm the senior manager for Corporate Licensing for Entergy.

MR. BONO: And we did bring some technical members of our staff that will hopefully be able to answer every question that you present to us today and provide the necessary backup to the director as needed. They will announce themselves as they make any presentation. Those are the people that we brought in attendance.

Our agenda today is we'll describe the FitzPatrick site, the current status, some history and highlights of both the licensing and the way we have maintained the asset over the years, an overview of our project, review of our cost, beneficial SAMAs, and then we have two specific presentation topics that we would like to present.

One is a drywell and torus monitoring that we do, and the other is a torus repair that we did based on finding indication on our course that we think is somewhat unique to FitzPatrick and worthy of a presentation. Then we'll open it up for any questions that we don't answer during the actual presentations.

MEMBER ARMIJO: Is anyone on your team prepared to talk about the fluence issues that currently are the subject of these open items or is the staff going to bring that up?

MR. BONO: We do have members here that can talk about that. We do have a slide on the open item that I think we can go through that level of detail when we get there but we do have some members of our staff that are prepared to answer where we're at, what we have remaining, and what are current results are.

The FitzPatrick site is located just outside Oswego, New York in upstate New York. It's just off Lake Ontario. It's a General Electric NSSS and TG. Stone and Webster was our architect engineer and our constructor. It's a BWR-4 with a Mark I containment. Right now our power limits are 2536 MWt thermal power which equates to approximately 881 MWe. We are --

MEMBER WALLIS: What is your snow load specification?

MR. BONO: Our snow load specification. Tom.

MR. MOSKALYK: Thomas Moskalyk. I'm a constructural design engineer at the FitzPatrick plant. The snow load specification is 50 pounds per square foot.

MEMBER WALLIS: Fifty pounds per square foot?

MR. MOSKALYK: That's correct.

MEMBER WALLIS: That's not much snow. That's only 10 or 12 feet of snow or something? (Laughter.) Thank you.

MR. BONO: It is another area that we are known for. We are once through cooling from Lake Ontario. No cooling tower once through condenser. We have a staff complement of approximately 650 people onsite.

Our current plant status, we started up our current cycle from our 17 RFO November 4, 2006. We had approximately a 300-day run at which time we were monitoring our safety relief valve leakage. We shut the unit down August 20th to repair that leakage. Started back up at 100 percent power this morning with leakage down in the low level so we repaired that condition and are running without challenge to safety or generation. Our next outage will be September 2008. We are on a 24-month cycle.

Just some licensing history from the plant. We did receive the construction permit in May 1970 with an operating license of October 17, 1974, which obviously brings us here today with a 40-year license. Began commercial operation July 1975.

We did do a smaller 4 percent uprate at the end of 1996 coming out of our outage in that time period. November 21, 2000 the license was transferred from the New York Power Authority to Entergy. On July 31 we submitted our application for license renewal.

Some major improvements that are complete. These are some things that we pulled out of our plant history. Obviously in the early '80 time frame we completed the Mark I containment modifications much like the rest of the industry with the Mark I containment.

In 1988 we implemented hydrogen water chemistry. I won't go through this whole list but 1998 we performed a ECCS suction strainer upgrade. 1999 we went through our first noble metals application. We have since had a second noble metals application. We have done some secondary plant upgrades, some --

MEMBER SHACK: Do you still inject zinc?

MR. BONO: We still do inject zinc. That is correct, into our feedwater system. More recently in 2006 our last outage we replaced our high pressure turbine rotor to do some indications that were identified in phased array of the turbine rotor. We have upgrade that to a new model block design from general electric.

MEMBER SHACK: Is that capable of an upgrade, too?

MR. BONO: The secondary system is capable of further uprate. Right now we are limited on the electrical side.

MR. BARTON: What is this 1990 power uprate? How long was that?

MR. BONO: That is the 4 percent. That's when we began the 4 percent uprate.

MR. BARTON: What equipment upgrades did you have to do for 4 percent?

MR. BONO: What equipment upgrades did we have to do?

MR. BARTON: Did you do at that time, yes.

MR. BONO: We did some secondary plan upgrades, most of it in the feedwater system, monitoring feedwater components for vibration and elements like that.

MR. BARTON: Okay.

MR. BONO: Then some of the other 2006 upgrades we had was the off-gas condenser replacement. Then, as I'll talk later, we did add a sparger to our HPCI steam exhaust line which we'll show later was the root cause of the through-wall indication that we identified at this stage.

MEMBER SHACK: Are there any other discharges into the torus?

MR. BONO: There are safety relief valve discharges and there's also a RCSI steam discharge into the torus.

MEMBER SHACK: Do those have spargers but those are still the old design?

MR. BONO: The SRVs are analyzed for the condensation oscillations that were the cause. The RCSI discharge line does not have a sparger. We have analyzed the configuration. I think later when we get into the presentation on the HPCI exhaust you will see the uniqueness of the way that discharged into the line. At that time we can communicate why the RCSI -- we are able to look at the RCSI line and did not have the same environmental geographical type indications or situations.

MEMBER WALLIS: You've got these condensation oscillations and big collapses of bubbles. Is that something that is audible in the plant? Is it quite noticeable?

MR. BONO: I would like to follow up on that. We do HPCI runs and we do have operators that monitor the HPCI runs. I think the challenge to the question, sir, is that the noise we had at FitzPatrick, how do you consider that for noisy plant with a sparger? That's a challenging question.

MEMBER WALLIS: The sparger presumably does away with most of the noise.

MR. BONO: I would like to be able to contact some of the operators back at the plant. What I can communicate is the difference in noise between the pre-start, pre-sparger runs of high pressure cooling injection, versus the post. I think that is the best way I can answer your question is did we see the noise change.

MEMBER WALLIS: I would hope you did.

MR. BONO: I know we did. At what level I would like to do a little follow up, Tom, unless there is something you can add based on the post-maintenance running or post-test running from the sparger repair.

MR. MOSKALYK: During the sparger repair -- Tom Moskalyk, structural design. During the sparger design I actually went down into the sparger room and listened to the sound from the collapse of the condensation oscillation from the HPCI exhaust. I noticed the sound. It was certainly a reverberating sound.

Following the sparger installation, which has a full series of one-inch holes, the frequency changes considerably. We have an eight hertz frequency before we add the sparger and went to about 250 hertz frequency and significantly less. There was really no noise after the sparger was installed, just a steam sound and really no residence at all.

MR. BONO: Does that answer your question, sir?

MEMBER WALLIS: Thank you.

MR. BONO: We have some future improvements. These are slated for our next refueling outage. One is to replace our main transformers. That's a capital end-of-life replacement to set us up for a longer operation. Core spray motor replacement is again end-of-life. We do see some minor oil leaks in that motor so we think that compared to the other ECCS motors that's the proper one to replace.

We are doing a breaker replacement in our 345KV switchyard. It has to do with a good study that identified a single phase to ground for this breaker would challenge this breaker so we are upgrading its duty cycle and its rating to allow to meet the grid study conditions. Those are three upgrades.

If you could back up for a second, Mike. I do want to point out these are some short-term upgrades we have at the station right now. In all the Entergy plants we have an asset management plan that identifies capital improvements over a 15-year period and 15 years in advance. I list three that we are planning.

We are in the final stages of planning for our upcoming refueling outage but we do have a plan that lays out 15 years worth of improvements to feed our capital budgeting process. Some highlights from that plan is just large motor replacements are sequenced out over time. We do have recirc pump overhauls based on their end of life and setting up for the longer run. Then we also have another condenser retubing based on end of life projections from our condenser.

MR. BARTON: You have tubing right now?

MR. BONO: Our condenser tubing right now we have titanium tubes in the upper regions but we also have the admirillity brass on the lower sections that are not steam impinged.

MEMBER ABDEL-KHALIK: With regard to high-pressure injection, have you had any problems with gas intrusion in the intake lines?

MR. BONO: We have not to my knowledge unless some of the staff that I brought here. We have seen no gas intrusion or high-pressure injection lines. I am aware of some of the Entergy PWRs that have seen that phenomenon but we have not seen that at FitzPatrick.

MEMBER WALLIS: Are you going to talk about your sprinkler systems and deluge systems at all?

MR. BONO: Sure.

MEMBER WALLIS: I was interested that they are normally dry?

MR. PECHACEK: Joe Pechacek. I'm the --

MEMBER WALLIS: There have been instances of water hammer at plants when these things get turned on and water comes down the pipe.

MR. PECHACEK: Yeah, we -- first of all, Joe Pechacek. I'm the Entergy program and components manager at the MPG FitzPatrick plant. I was also previously the principle fire protection engineer. We did review it and there were several significant industry events in the past going back about 10 years.

We did look at our systems and the number of systems that are dry that are closed heads are very, very small. In fact, diesel generators, our main turbine generator, and also the MG-7. They were actually supervised by us so those are the ones that are potential to having a water hammer event. We did look at a configuration of our piping and performed some limited modeling and we did not see that we had the same configuration as some of the other plans that had rather significant ruptures.

MEMBER WALLIS: So you did some analysis of what would happen?

MR. PECHACEK: In addition to what I just stated there was a very, very comprehensive fire suppression effects analysis that was performed that looked at flooding due to inadvertent operation and also fracture or breakage of fire protection lines. That is correct. Does that answer your question, sir?

MEMBER WALLIS: What would be the consequence if you did have a water hammer in the diesel area and it broke a pipe?

MR. PECHACEK: The diesel area there are some areas where we would have out-fall to some of the adjacent areas, the primary access to where there is a door to the screen lower area that we would have some out-fall there. There is also floor drains throughout the rooms that are 100 gpm.

Those are periodically surveilled to make sure that they do have that capacity. Given the relatively small size of the system the diesel generator rooms are, I believe, either six or nine sprinkler heads, the floor drain system along with out-fall just through door gaps would be more than able to take care of the water that would be discharged.

There also is a series of curves that would preclude flooding in the adjacent division as well. Does that answer your question?

MEMBER WALLIS: I might come back to it. Let's see where you go.

MR. BONO: Just a kind of overview of our project and the way FitzPatrick went about submitting the application. We do have, as the other Entergy plans have, we have experienced multi-discipline Entergy team preparing our license renewal applications. We did incorporate lessons learned from previous applications for FitzPatrick. This is a continuing process for us at Entergy.

Just as an example, even after our submittal, we did identify that some issues in the Vermont Yankee scoping that we went back and did further walkdowns over spacial concerns, fed that back into our amendment. It was reviewed during the regional inspection and we did incorporate those into our amendment 11 so we are trying to learn from the process as the other Entergy plants are further along through it.

CHAIRMAN BONACA: The question I posed before to Mr. Young because we have seen Mr. Young in the other license renewals and that was my question, you know, how credible is the scoping that you did at FitzPatrick given that you had this problem at Vermont Yankee. The answer was that it was -- I mean, the approach was correct. In the implementation there was a mistake or problem in the turbine.

MR. YOUNG: This is Garry Young. The Vermont Yankee situation was the same methodology we used at FitzPatrick but at Vermont Yankee we had a database that we were using in the turbine building to identify those locations that needed to have systems in scope for a(2) and there was some data missing from that database that we did not catch at the time and it was caught during the Region inspection. After we learned that lesson at Vermont Yankee, we did go back and double check FitzPatrick and ensure that we didn't have the same problems.

CHAIRMAN BONACA: Who caught it during the regional inspection?

MR. YOUNG: Who caught it?

CHAIRMAN BONACA: Yeah.

MR. YOUNG: It was during the walkdowns.

MR. MEYER: This is Glenn Meyer. I have looked at the scoping for Pilgrim, Vermont Yankee, and for FitzPatrick and I identified the problem. I can talk to that during our discussions.

CHAIRMAN BONACA: When we come to the scoping portion. At some point you're going to talk about scoping. Right?

MR. MEYER: That is correct.

CHAIRMAN BONACA: That would be the time just because that is a question that the committee will raise, why is it okay for FitzPatrick.

MR. BONO: I think one of our points here is understanding we started from a different place with the database, we still looked at that and did physical walkdowns in our facility to make sure we didn't have some of the same things. My point is as a project we are trying to take those lessons learned from those plants and we applied them to FitzPatrick.

CHAIRMAN BONACA: Let me ask one more question. Have you looked back to the other plants?

MR. YOUNG: Yes, we've gone back and looked at the Pilgrim plant to see if there were any problems there. The specific issue that happened at Vermont Yankee from our review was each plant has their own type of database and this was a slightly different approach to the database than we had seen previously. That's why we had this oversight but we haven't seen that in any of our other projects and we're doing the walkdowns to verify as part of the --

CHAIRMAN BONACA: Did you have many other plants that you looked at before?

MR. YOUNG: Yes. Arkansas 1 and 2 are the other plants that we looked at and we did identify -- in those cases we did -- this was an electrical equipment and a straight pipe run type issue that didn't show up in the database. We had already identified those types of equipment in the Arkansas applications.

MEMBER MAYNARD: For the record, tomorrow you will probably get a chance to answer that again for the Pilgrim station.

CHAIRMAN BONACA: It's important because corrective action program and then implementation of lessons learned is such a fundamental stepping stone in the license renewal program just because you ought to have something working that way so that's important that you did those things for verification.

MR. YOUNG: Yes.

MR. BONO: You bring up a good point. The corrective action program at Vermont Yankee was used and that lesson learned was applied into our application and Garry can speak to that.

MEMBER WALLIS: So you had this peer

review and you had this very experienced team. When the audit happened there were a huge number of questions and quite a few resulted in changes to the LRA. The audit presumably was after all this. Wasn't it?

MR. BONO: The audit was after our internal reviews and our peer reviews.

MEMBER WALLIS: I just wonder why they caught so many things.

MR. COX: I think you've got to look at the nature of -- this is Alan Cox with the License Renewal Team, Entergy. There were a lot of changes made but I think a lot of those were clarifications. I don't think most of those were significant issues.

MEMBER WALLIS: Those seem to be fairly small.

MR. COX: Right. For whatever reason we had a lot more audit questions at FitzPatrick going into the audits than we had at the previous plants. Each audit team's makeup is a little bit different so the circumstances are different.

MEMBER WALLIS: It was the enthusiasm of the team that led to all these questions?

MR. COX: I think Mr. Chan picked out a good team for FitzPatrick. Pretty impressive.

CHAIRMAN BONACA: By the way, this is the first application for which we see that the audit has been integrated in the SER. Although the SER now has become huge, still there is one place as a focus. That's good. I like that.

DR. KUO: Great.

MR. BONO: I think the members of the FitzPatrick team will agree that we have a very challenging audit and it was an enthusiastic team. All the comments from our internal review we incorporated those before we submitted the application.

As part of our commitment structure at Entergy we do track all the commitments both by commitment tracking system and a work tracking system that ensures that we'll have all commitments implemented prior to the period of extended operation.

I will note we have begun taking a fleet approach to some of these commitments as they are very similar among the different boiling plants so as we implement program enhancements or new programs, we'll be doing those as a fleet and implementing those in that fashion so we can all learn from the same process.

Thirty-six Aging Management Programs and

17 programs in place without enhancement. Nine programs we will have to enhance to meet the requirements of the license renewal. We will be developing 10 new programs.

As far as GALL consistency, 10 were consistent. Twenty were consistent with exceptions and enhancements. Fifteen of those 20 were more on the exception side so five of those were enhancements to come to consistency with the GALL and then six plant specific programs.

MEMBER ABDEL-KHALIK: So the tracking system is fleet-wide?

MR. BONO: There is -- the commitment tracking system and the work tracking system are fleet programs. That is correct.

MEMBER ABDEL-KHALIK: And where is the QA for that fleet-wide program done to make sure that it's consistent with the individual unit commitments?

MR. BONO: The commitment tracking system is actually a subset of the same software that runs our corrective action program and that gets that level of oversight. We do have a regulatory compliance department at the site that monitors commitments and any change to those goes through that level of review and approval.

MR. COX: This is Alan Cox. Let me clarify that. I think, Steve, the process is a fleet-wide process but the actual implementation is by each site. I believe that's correct.

MR. BONO: That is correct. Did I misunderstand the question?

MEMBER ABDEL-KHALIK: When you said the process is fleet-wide there is obviously a time line for the individual elements within the matrix of things you have to do. The question is how does that fleet-wide matrix match with the individual plant commitment?

MR. COX: Really each system is maintained individually by the plant. It's the tools or the program used as a common program across the fleet.

MEMBER ABDEL-KHALIK: Thank you.

MR. BONO: The timeline would be established by the most limiting plant. Is that kind of the line of questioning?

MEMBER ABDEL-KHALIK: Right, if you are going to implement these changes fleet-wide.

MR. BONO: Right now the commitment dates are all prior to the period of extended operation. I guess what I'm trying to communicate is we may implement in advance of that as a fleet to support VY period of extended operation which might be before ours. Right now the dates all look like they are on the 2014 date but we would do that as a fleet to develop the program and then they would be site implemented each program.

MEMBER MAYNARD: But still for the site it's easy to identify what commitment, what requirement, what corrective actions of various things you've got for that site. It's accessible to the rest of the fleet but it's not something that you're tied up by something some place else.

MR. BONO: That is correct. It is our system and it's easy to recognize our corrective actions and our commitments.

MEMBER MAYNARD: Even as a fleet, it's still identifiable to FitzPatrick.

MR. BONO: It is a FitzPatrick commitment.

MEMBER MAYNARD: Gotcha.

CHAIRMAN BONACA: I have some questions regarding the exceptions you mentioned. Is this the right time to ask questions or do you want to put it off until after the presentation?

MR. BONO: Okay. Would you like to go through the programs with exceptions?

CHAIRMAN BONACA: Yeah. Are you having a

presentation about the programs later on?

MR. BONO: We didn't have a separate --

CHAIRMAN BONACA: Let me ask a couple of questions. One that struck me was you have the BWR vessel internal program. There are five exceptions they should have there. The first inspection is you do rely on ringhold dam bolts and you have no wedges to prevent lateral motion of the plate during blowdowns, for example.

I understand that they are going to be committed to do something by two years before getting in the area of center vibration which is either you are going to install the wedges or you are going to perform an analysis to demonstrate that you don't need them

MR. BONO: That's correct.

CHAIRMAN BONACA: The question I have is, and maybe it's a question to the staff, is why is it acceptable now? Why is it acceptable to operate now with that issue? The issue is not only a license renewal issue, it's a current issue

DR. KUO: In fact, almost every issue that we look at are current issues. In license renewal our basis for review is the current licensing basis.

CHAIRMAN BONACA: Well, some issues are

specifically license renewal in the sense that right now I was questioning myself and saying if you're concerned about lateral motion of the plates during a blowdown in license renewal, wouldn't it be the same now? I mean, it still should be the same.

DR. KUO: There are issues as such that you mentioned. What we normally do is that when we identify issues like such, we will actually pass the issue to our tech divisions, project management divisions for them to look into it.

CHAIRMAN BONACA: It seems to me that if you come up with an analysis that says that the holddown bolts are not sufficient, then you would have to install the plates, the wedges now when you refuel the plant.

MR. BARTON: Wasn't there an analysis that said that they are okay for the first 40 years of operation?

CHAIRMAN BONACA: I didn't see that.

MR. PECHACEK: Let me just jump ahead to the FitzPatrick programs and components. We currently have an engineering evaluation that supports operations without the BWR VIP recommended reviews of the holddown bolts because of the absence of technology needed, the UT from above or ultrasonic testing or enhanced digital inspection from below.

That is actually common. There are actually quite a few boilers that just because of access and not having available technology so that evaluation provides assurance that given the current license that is our licensing basis. I have some more specifics that I can dig up if you are interested.

CHAIRMAN BONACA: BWR VIP says that you're okay. By BWR VIP you should do one of two things that you are committing to do for license renewal. Anyway, this is an issue that doesn't have to do with the license renewal itself but it is a concern with the licensing basis that I think should be addressed. Do you feel right now you believe you have in place an analysis review by the NRC?

MR. PECHACEK: We have an evaluation that was performed in accordance with the BWR VIP guidelines. It is obviously available to the staff for review. In fact, I recall discussing it during one of the audits with our BWR VIP program when the NRC was on site.

CHAIRMAN BONACA: And that was two years before the event?

MR. PECHACEK: That is correct. Additionally, we are performing additional inspections that, again, do not meet the true intent of the BWR VIP guidance but they also provide reasonable assurance such that there is actually a welding lock on the nuts. These are the core plate nuts and that provides additional insurance. That is part of the technical basis for the engineering evaluation.

CHAIRMAN BONACA: All right. The other question I have is regarding the exceptions 3 and 4 where you have a number of deferred inspections. I was trying to understand the basis for deferring the inspection. You said you had a technical basis but really in both places in the SER it states that it was postponed because of management decision. Well, I mean, that could be a bad management decision. I don't know.

MR. PECHACEK: Just to clarify also, I think that was basically the previous outage. Again, 2006 October we completed our refuel outage 17 and we are current with required inspections that can feasibly be performed. Specifically with the jet pumps we provided full UT on our group 2 beams that were replaced in '92. We also performed jet jump internal UTs on all jet pumps.

CHAIRMAN BONACA: Now for the welds which are inaccessible, exception No. 4. Do you foresee that some technology will come and they will have to inspect those?

MR. PECHACEK: That is something that we are aggressively working with the industry. We actually have a number of our plant staff on the inspection focus team for the BWR VIP. I know that group in conjunction with EPRI is further looking at technology.

In fact, you could even look at the technology to do internal jump pump UT inspections that five or six years ago wasn't available. As it becomes available we will look at all technology that is available to complete inspections that are currently not reasonable.

CHAIRMAN BONACA: Meanwhile you have confidence that without inspections you still can operate safely?

MR. PECHACEK: That is correct. Again, the VWR VIP requires that the owner and the licensee have an evaluation that provides a technical basis for not performing the inspection. They also recognize in some situations that the technology at this point is not available to perform those inspections.

MR. BARTON: Since we are on the subject, I have a question. In RO 16 you found cracks in the steam dryer. You looked again in 17 and 17 has come and gone. What did you find?

MR. PECHACEK: Seventeen we found a couple things. First of all, we found a new crack. It was southwest quadrant, near one of the guide rods several inches long. It was actually through the middle of the weld so, again, not integrating stress corrosion cracking but apparently fatigue in that area. That was removed, ground out, and repaired.

We also had on the top of our steam dryer eight blocks that were originally for start-up testing, vibration testing. We had indications along the perimeters of those blocks that were previously found back two outages ago. We thought we had found additional indications.

Once we went back and reviewed the tapes from the previous outage, we found out that they were already there and we had an existing indication. I believe it was found in 2004 on the skirt area. Again, that was looked at in subsequent outages and there was no change in the crack. Again, we'll go back and look at all these indications.

CHAIRMAN BONACA: Even though there were cracks in the shroud the vertical welds are stable.

MR. PECHACEK: Yes. That is correct. We

had some challenges previously due to our shroud configuration with a 10 tie rod repair access. We did work with GE to come up with some techniques to a lot of areas where we only had visuals. We were able to go in with UT and better characterize those welds and the indications that are present.

CHAIRMAN BONACA: Thank you.

MR. PECHACEK: You're welcome.

MR. BONO: I think we've covered -- we're into program implementation and I think we have talked about how it will be a fleet approach. The commitment is a FitzPatrick commitment.

In the scoping phase we did utilize our component database and, as we talked about before, we started with the spacial configuration was better covered in our data base than I think the historical VY submittal which led to some of their issues. We used our drawing system and isometrics and we looked at the actual cable and piping locations which we performed walkdowns as part of our scope verification. We also reperformed that based on the Vermont Yankee operating experience.

The regional inspection verified our scoping in all plant areas and that will be discussed later. We did make scope changes based on both the regional and our own walkdowns. All those have been incorporated in Amendment 11 to the application. We had a conclusion that we had an acceptable method for scoping and screening of non-safety-related SSCs. Any question on the scoping and screening process? I know you talked a little bit in detail before.

CHAIRMAN BONACA: No. We'll hear from the staff in the afternoon.

MR. BONO: The next area we were going to discuss was the two open items. The draft SER has two open items for the FitzPatrick submittal and no confirmatory items.

The first open item deals with our vessel neutron fluence. Our current pressure temperature curves are valid through 2014, our current licensing commitment. We will be submitting fluence analysis per Reg Guide 1.190. Right now that draft analysis has been complete and it's in our Entergy review process looking for the more limiting fluence issues.

The draft right now has some results from our draft. The axial weld failure probability is limiting and our adjusted reference temperature and our upper shelf energy values will not be challenged based on that draft analysis at the 54 effective full power years.

MEMBER SHACK: I take it the problem here is not the use of the RAMA analysis that caused the problem at Pilgrim. It's somehow your verification of your surveillance capsule data?

MR. BONO: George, I don't know if there is anything you want to add. George Rorke is a member of our technical staff. Part of ours was in the method of the analysis and the way we incorporated Reg Guide 1.190. When our analysis was done we had done G. We had used General Electric for that and they had looked at the guidance in draft form and felt we were in compliance.

George, is there anything you want to add?

MR. RORKE: No, I think that's the case. This is George Rorke.

MR. BONO: It wasn't a case where I know with Pilgrim and their benchmark not being valid. We don't have that same code restriction. It's more a case of becoming current to the new Reg Guide.

MEMBER MAYNARD: You did use the RAMA code or you did not?

MR. BONO: We did use the RAMA code.

MEMBER MAYNARD: You did? You don't have a benchmarking issue. You were able to benchmark with your capsule?

MR. BONO: BWR-4 plant there's plenty of benchmark data with the RAMA code for our unit.

MEMBER ARMIJO: I would like to know is there a substitute issue here or is it a regulatory language issue? Are the fluences changed as a result of your most recent analysis?

MR. BONO: George can speak to that.

MR. RORKE: This is George Rorke from Entergy. Actually, in general the fluences are decreased at 54 EFPY within the methods. There are some peak locations that are higher but they are not limiting in the ART and the USE.

MEMBER ARMIJO: Okay. So when the staff found discrepancies in your initial submittal or initial application, those discrepancies weren't based on some sort of problem with the fluences being incorrect?

MR. RORKE: That's correct. The questions all had to do with methodology use to arrive at the fluence estimates we made in the original application.

MEMBER SHACK: That doesn't address -- the more I read the SER is that everybody agrees the results that you have are probably right but you hadn't completely completed the verification. That is sort of the way I'm taking what I read in the SER.

DR. KUO: The staff will have some explanation.

MR. LOIS: This is Ambrose Lois, Systems Branch. Both calculations for FitzPatrick as well as Pilgrim were done by GE at a time before we approved their code. GE's code was an elaborate review. It took about three years and came into effect in 2001. The objective of the review of both of GE's methodology as well as RAMA code was to have the same calculation with each other's uncertainties.

Now, the uncertainties are approximately 20 percent, the legal limit. That was established way back in the '70s. Today uncertainties are within about 7 to 8 percent. However, because both calculations were done before GE's code was approved, it could have some biases which we were not aware of.

Now, the RAMA code is approved for BWR-4. However, for 3s, namely Pilgrim, we did not have any benchmarking. That's where the problem came about. As far as 4s are concerned as far as FitzPatrick is concerned, it's okay. There's no regulatory difficulty.

MEMBER SHACK: Would you agree for bullet 4 that you think when they straighten up their analysis it's still going to come out with the art and the upper shelf are going to be okay at 54?

MR. LOIS: Yes, absolutely.

MEMBER SHACK: So there's no substantive issue here?

MR. LOIS: Exactly.

MR. BONO: So I think we've wrapped up the fluence discussion but, like I said, we have completed the draft analysis that's in our review process and we come to that same conclusion that our current limits are bounding in five of the six areas and there will be no change in the 54 EFPY.

Environmentally assisted fatigue, we put these slides together.

MEMBER ARMIJO: Before you leave that, I came across something I didn't understand in your license application. There was a table 4.2-2 that listed the upper shelf energies in the unirradiated condition and also the projected for 54 effective full power years.

That table shows the lower intermediate shell in the unirradiated condition, upper shelf energy of 67 foot-pounds. I thought the number was supposed to be greater than 75. Is that a typo? All the other numbers were above 75 which was required but this number was 67. I didn't understand why that was there.

MR. BONO: I think we're going to have to get that information and look at the application and we'll have to come back. I don't have that level of detail with me right here. I have the draft results but I don't have --

MR. LE: I think the staff has some comment on that one.

MR. ELLIOT: This is Barry Elliot. I don't have the application in front of me. I'm taking your word for it that it says 67 foot-pounds unirradiated. The requirement in the regulation is 75 foot-pounds to start but the limiting condition is the 50 foot-pounds as far as irradiated condition. As long as they satisfy the 50 foot-pounds in the irradiated condition they were satisfied with the reactor vessel. The 75 is a critical issue if you have high copper plates. Apparently they do not. They must have low copper plates so that they can still meet the 50 foot-pound energy requirements.

MEMBER ARMIJO: Yes. In the projected 54 effective full power years they were meeting the 50.

MR. ELLIOT: Okay.

MEMBER ARMIJO: But there was this beginning number of 67 which looked odd. T other thing on that chart, that table, is that there were no data for the welds, the axial or no data on the --

MR. ELLIOT: This plant was built before the requirements for upper shelf energy was started so they were only meeting the ASME code at the time the vessel was fabricated. There was not an upper shelf energy requirement. There was just a 10 degree fahrenheit test temperature requirement and they satisfied all those requirements.

They are not the only BWR that has this issue. Most of the BWRs do not have data for the welds. GE went out and instead of getting data for the welds specifically for each individual weld they did a generic evaluation for different types of welds, different type of weld materials. They were able to show that the upper shelf energy would drop to some particular values at the end of the life of these plants.

Some of them were shown to drop below 50 foot-pounds. If they were shown to drop below 50 foot-pounds, GE did what was called an equivalent margin analysis to show that they could meet the margins of Appendix G of Section 11 of the code with the lower upper shelf energies. That's what you're looking at there.

You are looking at that GE did the analysis and they set criteria, certain foot-pounds that every plant must have in order to satisfy their generic equivalent margin analysis. That's what we review to see that if each plant is capable of meeting those generic foot-pound at end of life for the welds.

MEMBER ARMIJO: So the staff had previously reviewed the GE analysis and found it acceptable.

MR. ELLIOT: Yes.

MEMBER ARMIJO: And that analysis applies to the FitzPatrick --

MR. ELLIOT: That's right. We had to look at the materials.

MEMBER ARMIJO: I didn't understand what EMA was.

MR. ELLIOT: EMA is equivalent margin analysis and that is the analysis that GE performed, we reviewed it and approved it, and now we have to make sure that they have satisfied all of the foot-pound Entergy requirements that we say are the criteria now. That's what we review.

MEMBER ARMIJO: That clarifies it.

MR. BONO: Does that answer your question, sir?

MEMBER ARMIJO: Yes. It sure does.

MR. BONO: Is there anything else you guys want to add? Actually, our presentation on environmentally assisted fatigue is going to be a little redundant to our discussion earlier not recognizing we would have that discussion. We did make commitment 20 that we will demonstrate the cumulative usage factors and we will use the ASME code as part of that analysis. We'll utilize design transient information and specifications for BWR.

As part of our analysis and part of our commitment we will be incorporating this into our fatigue monitoring program and we'll manage the effects through that monitoring program. I know we had that discussion earlier. is there anything we need to talk about in the environmentally assisted fatigue?

Okay. In the severe accident SAMAs we did review the six potentially cost beneficial SAMAs. There are no age-related SAMAs at FitzPatrick. We are implementing those based on our plant specific analysis and the cost benefit. We have implemented one SAMA related to our EDGs rooms and opening of doors in a procedure change.

One is being implemented this year that

requires some design work to allow portable battery charger and the four remaining ones have to do with battery loading conditions for our HPCI and RCSI operations. Those are being looked at but none of them are age related.

MEMBER SHACK: Just our of curiosity your internal events PRA is 3.7 times 10 to -6. It's already small. All your SAMAs look at that. Your fire is 2.56 times 10 to -5. It's about 10 times bigger. Nobody seemed to look at anything that might help that part.

MR. BONO: Actually, I think the SAMA implemented was based on the fire in the EDG. I

MR. PECHACEK: I don't recall. We'll follow up on that issue. I know there were some previously --

MEMBER SHACK: I could be so expensive. I mean, the table spreading room, the main control room and the relay room.

MR. PECHACEK: The cable spreading with chemical force is a high contributor and we have an option to install fixed detection and we took an alternate approach with restricted combustibles. Some of the others that did come up previously have been re-reviewed as part of the separate --

MR. BONO: We can follow up on how we have looked at the fire PRA analysis and the SAMAs associated with that.

MEMBER SHACK: The intent was to look at things based on the complete PRA.

MR. BONO: Okay. We did have two specific presentations based on FitzPatrick specifics. First one had to do with our containment, drywell and torus monitoring. That is BWR-4 kind of generic picture. It highlights the torus and the downcomer area to the drywell.

If we go ahead a couple of slides, Mike, you can see we do have the same cushion. We do have sand cushion drain lines similar to most BWR-4s and we have the air gap between the concrete and the drywell shell. And we have an internal caulk seal that is inspected every refueling outage. Some specifics on our drain conditions. We do --

MEMBER SHACK: Do you have this fibry stuff? What's in your gap? What did you use for that initial construction?

MR. BARTON: On the vertical section.

MR. BONO: On the vertical section we can confirm this but there was a construction and then the insulation material was removed.

Tom, is there anything you want to --

MEMBER WALLIS: So it's a real gap?

MR. BONO: It's a real air gap.

MR. BARTON: No firewall D.

MR. MOSKALYK: The material that is used is ethafoam material and that was removed. That was identified. The material was removed leaving the air gap.

MR. BONO: In our drain we do have bellows drains. Prior to every refueling outage we do monitor a flow switch. The way our drains are configured any leakage would enunciate. It's based on a flow switch configuration such that the flow switch opens to allow any leakage. It takes one gallon to open the check valve to get enunciation but any leakage is captured and it would be enunciated.

MR. BARTON: Do you ever test a full switch to make sure it works?

MR. BONO: We test a flow switch prior to every outage. Larry has the details on how we do that but we open drain and they are allowed to pour one gallon in and ensure we get enunciation.

MR. LEITER: This is Larry Leiter, system engineering from FitzPatrick. That's correct. The full switch has a collection chamber and downstream of that is a weighted check valve and we test it by pouring water into the drain from some available upstream access point. They are allowed to pour in one gallon and the one gallon is supposed to fill the collection chamber sufficient to alarm the switch.

The weight of that is sufficient to open the check valve and drain it back out. That test has always passed. We have not had a surveillance barrier on that. The outboard one prior to shutdown for each outage and the inboard one which actually inside the drywell we test as soon as it's accessible prior to follow up.

MR. BARTON: Thank you.

MEMBER MAYNARD: So this flow switch isn't a flow --

MR. BONO: It's not a flow rate.

MEMBER MAYNARD: -- flow rate based on quantity.

MR. MOSKALYK: It's capable of measuring flow rates of greater than 1 gpm but the alarm set-point is such that it would alarm on a trickle and however long it took to collect a gallon of that water.

MEMBER MAYNARD: As long as it collected it faster than it evaporates.

MEMBER SHACK: The limiting --

MR. BONO: That's our point in bringing it out. It is not a rate that cannot be detected. Like you say, as long as it is greater than evaporation, we would detect the leakage.

In the next area we show our sand cushion drains. We have done boroscopic inspections of these areas, once in 1989 and once in 2007. Both of those indicated no leakage so we have no evidence or no history of leakage down into this area.

Just kind of a summary, some summary bullets on our drywell monitoring. I talked about the boroscopic inspections. We do a visual inspection of the interior drywell caulk seal every outage.

MEMBER WALLIS: How recent were these?

MR. BONO: How recent were the boroscope or the --

MEMBER WALLIS: All these inspections. How recent were they?

MR. BONO: The drywell caulk seal was in 2006. It's inaccessible during plant operations so it's every outage when the drywell becomes accessible. The boroscope inspection was in April/May time frame of this year.

MEMBER WALLIS: So these are all pretty

recent. Thank you.

MR. BONO: These are all pretty recent. I would agree. The coating systems are carbozinc 11 with epoxy and it is inspected in accordance with our IWE program during refueling efforts.

MEMBER SHACK: Is that the original coating or is that a replacement?

MR. BONO: That is the original coating. Am I correct, Tom?

MR. MOSKALYK: Correct.

MR. BONO: Under torus monitoring we did do the shell inspection in 1998 when the torus was drained for our installation of our suction strainers. As I depicted earlier, it does use a carbozinc 11 for our coating system and it is in inspected in accordance with our program.

MEMBER WALLIS: Do you have suction strainers like the Vermont Yankees one with disks?

MR. BONO: We do have the circular disks, Tom? I'm not sure of Vermont Yankee's design to be honest with you. Tom, can you describe our suction strainers? I know they are a circular disk.

MEMBER WALLIS: They are stacked disks but they are horizontally stacked.

MR. MOSKALYK: The RHR suction strainers

are horizontal. They extend two bays, each of the RHR suction strainers. The core spray suction strainer I believe is another horizontal strainer and the HPCI strainer is vertical.

MEMBER WALLIS: They are disks.

MR. MOSKALYK: They are disks.

MR. BARTON: Have you found blisters on your interior coating when you examined it, inspected it? Have you found blisters to repair or is the coating relatively intact?

MR. BONO: The coating has been relatively intact. Tom, if you want to give -- we're talking about the torus coating. Correct?

MR. BARTON: Have you found blisters when you have inspected the torus coating?

MR. MOSKALYK: Torus coating actually there is some blistering in the torus coating below waterline. We are currently monitoring the areas where a pudding has resulted. We did a complete drain-down for the ECCS suction strainer modifications back in 1998. During that time there was a very, very thorough inspection, ultrasonic inspection of the areas in which there was any pitting. That is being monitored during every refueling in 2004 to 2006.

MR. PECHACEK: We currently perform

reviews using UT at about 3 by 3 grids. Those are the areas that had the most limited fitting.

MEMBER ARMIJO: Where were there pits, at the waterline or below the waterline?

MR. MOSKALYK: These pits are generally below the waterline. What we've seen is somewhere around the 5:00 position roughly below waterline there are 16 days looking at the data from 1998. There are about 10 locations we look at. I think there are four bays involved, two locations per bay. One bay, I think, had three locations. There are the areas that we actually monitor and they are below waterline.

MEMBER WALLIS: What is the point of this picture?

MR. BONO: The point of this picture is the next series goes to the construction phrase that we have for our drywell ending with a coated containment. It's just to show the construction phase progressing through the construction phase and then with the final being a pristine coated --

MEMBER WALLIS: Are we supposed to notice any particular feature of this?

MR. BONO: I was just going to move through these to show the construction phase. The one with any purpose is the last photo, the one being shown now that shows the final coated containment.

CHAIRMAN BONACA: Let me go back to the drywell monitoring because I think when you pass through the curve drywell monitoring relies on inspection. That is a visual inspection. Isn't it?

MR. BONO: That is correct. A visual inspection.

Tom, can you describe our drywell coating inspection program?

CHAIRMAN BONACA: I would like to know if you have any specific, for example, you have to form UT indications.

MR. BONO: Not on the drywell monitoring, only on the torus as we spoke of before we had identified pinning.

MEMBER SHACK: I thought somewhere it said you did some in the sand bed.

MR. PECHACEK: No, we performed boroscope visual.

MEMBER SHACK: Boroscope.

MR. PECHACEK: Boroscope visual.

CHAIRMAN BONACA: I misunderstood. I thought it UT.

MR. PECHACEK: No.

CHAIRMAN BONACA: So essentially you have the two basic technical issues to depend on. One is that you have no noticed water intrusion to justify corrosion.

MR. PECHACEK: That's correct.

CHAIRMAN BONACA: Your visual from the inside identified the coating peeling or degradation.

MR. PECHACEK: That's correct.

CHAIRMAN BONACA: And you're performing visual inspections every fall.

MR. BONO: Tom has the details on the visual program.

MR. MOSKALYK: We perform visual inspections of the interior of the drywell coatings. That is actually performed as part of the IWE program. Part of that also is visually inspecting the caulk seal at the interface between the drywell shell and the concrete floor at the base of the shell.

CHAIRMAN BONACA: Has the caulk seal been always in place from construction time?

MR. BONO: That is the original caulk seal.

MR. MOSKALYK: Original caulk seal, yes. It has good integrity. We have not seen any degradations in the caulk seal.

MEMBER ABDEL-KHALIK: What is the

elevation at the bottom of the drywell?

MR. MOSKALYK: Drywell elevation is 256.

MEMBER ABDEL-KHALIK: Compared to sea level?

MR. MOSKALYK: Oh, yes. Elevation compared to sea level 256.

MEMBER MAYNARD: They are not on the ocean.

MEMBER ABDEL-KHALIK: Right. I'm talking about possibly ground water seeping up.

MEMBER SHACK: You want the level compared with the lake?

MEMBER ABDEL-KHALIK: Right.

MR. MOSKALYK: Lake level is somewhere around 244. I'm not sure if that's low lake or if that's just normal lake level but it's about 244. We are roughly about 10 feet or 12 feet above lake level.

MR. MEYER: If I could add to the discussion. We talked at the Pilgrim meeting about the issues that Pilgrim had with ground water and how it affected their torus room. I think the key picture they've got is not the last one but the first one where it is shown that at FitzPatrick it is actually rock they had to blast out, excavate.

Their drywell and torus are sitting on

rock whereas at Pilgrim it was so soft and sandy they had to put a temporary footing down to even construct the plant and that is what got into the discussion of the joints in the construction and how water was able to penetrate. Here they are adjacent to a large body of water but they are also basically carved out of bedrock and I think it's a considerably different situation.

MEMBER WALLIS: That's helpful. I wonder what this thing was really showing me but now you've explained it. Thank you.

MR. PECHACEK: Just if I could follow up on what Glenn just stated also. I walked down to the torus area during one of the inspections, actually several times. Look at this first photograph. If you notice, the drywell pedestal is sitting on the raised portion of rock in the middle and the torus room per se is the outer perimeter there where you see the rebar. Likely any water that you have in the area you would see the torus in the lower elevation. Again, that area we walked down and there are no signs whatsoever of water seeping in from the exterior areas.

MEMBER WALLIS: I am looking at a picture that shows this shell is festooned with piping that sticks all over the place.

MR. PECHACEK: Penetrations.

MR. BONO: Those are the drywell penetrations.

MEMBER WALLIS: It shows something one might not be aware of.

MR. BONO: If there are no other questions on the drywell or torus monitoring, we will go into the torus repair which is going to be unique to FitzPatrick. In June 2005 we did identify a through-wall leak indication in the torus. It was located in the same bay that the HPCI steam discharges into and it was near a ring girder gusset plate.

We'll go through some of that location because I think the location of the discharge of the steam and the support structure, both the outside support and the ring girder support played a key role in the stresses that were seen at that location.

MEMBER WALLIS: How did this compare with the predicted fatigue life using the methods which we heard about before?

MR. BONO: It was -- this condensation oscillation was not in --

MEMBER WALLIS: I thought there was a formula for calculating the loads from your selection and you know how many times you've implied them so you could calculate a fatigue line.

MR. BONO: The condensation oscillation is characterized in our safety relief valve discharge but I don't think that analysis --

MEMBER WALLIS: You have some sort of curve or load.

MR. BONO: I don't think that analysis moved over to our HPCI steam line. I think the condensation oscillation analysis you're talking about was specific to our safety relief valve. The HPCI steam line was not analyzed in that method and that led to the problem.

MEMBER SHACK: The postulate is as I read the information that if you operated this thing for 14.5 hours during the blackout and you've got a 4.6 inch crack.

MR. BONO: We put in the information notice the impact of the blackout because that was a HPCI run that was not typical for the site. Normally it's a quarterly within one shift kind of evolution. That was a long run fairly close. The 4.5 inch crack obviously propagated through the cycles. That's why I thought it was important to add that information. We did do the code repair.

MEMBER WALLIS: Vibration fatigue, is that a hypothesis or is this some kind of confirmation by analysis or what?

MR. BONO: Tom, you can speak to that if you would like. There was a confirmation when we removed the flaw area. We did send that off for a lab confirmation.

MEMBER WALLIS: You said it was due to the HPCI. Was that the only thing you thought could have caused it or did someone actually analyze the stresses?

MR. BONO: We did analyze the stresses from the condensation oscillation.

MR. MOSKALYK: We actually did both. We analyzed the stresses in that bay to determine the number of cycles. We established the stress levels at that location, the number of cycles that would cause that to crack. We also had a lab review that. They actually did a metallurgical analysis to confirm that it had beach marks and also confirmed that it was a vibration fatigue issue.

MEMBER ARMIJO: So you looked at the fracture surfaces and confirmed you had a fatigue.

MR. MOSKALYK: That's correct. We did both. We did both analysis and lab testing.

MEMBER SHACK: Was it assumed to be there before this long run associated with the blackout or was this basically a blackout generated by --

MR. MOSKALYK: What we did is we didn't know when the crack initiated. What we had to do was establish what stress levels over the duration of operations would have caused it. We actually counted the number of days or hours the HPCI was run from day one including the blackout. We established what stress levels would cause -- what alternating stress levels would cause a crack to occur at that size at that point in time.

MEMBER SHACK: What fraction of that growth was in the blackout? Any idea?

MR. MOSKALYK: I do not have that information.

MEMBER SHACK: Station blackout coping analysis. The crack had grown so large that you wouldn't have met that.

MR. MOSKALYK: I don't have that information with me.

MR. BONO: I don't know that we calculated how much of that was --

MEMBER WALLIS: There's only one HPCI exhaust?

MR. BONO: There is only one HPCI steam exhaust. The RCSI system much smaller system does have a steam exhaust in a separate bay. I think the next couple pictures here kind of show the condition that was set up. Its configuration is different in that it does not impact directly by ring girder support. It does not directly impact onto the torus shell.

MEMBER ARMIJO: Is FitzPatrick unique with the HPCI arrangement compared to other BWR-4s?

MR. BONO: We did find that as part of this in our extended condition. We went and we did an information notice and we used the operating experience network. We did find, I believe, one other plant that had a similar steam line configuration than FitzPatrick.

I would have to confirm the details on that but I can tell you there were other susceptible. I believe it was only one. It may have been two other plants that we shared this information. Most plants had a steam sparger installed in their HPCI lines in the torus.

The next series of slides here kind of show the geometry here. You see a cross section of the torus with the outside support and the ring girder. You can see the two gusset plates. The lower gusset plate is where we actually saw the lower gusset plate as it met the support column on the outside of the torus is where we saw the cracking.

We did see in our extended commission reviews in that next outage some surface. No through-wall indication but some surface indications on the gusset plate directly above it that we ground out and repaired for the code. This is actually a pre-sparger picture that we found in our archives and you can see that the open end discharge line pointing toward the torus shell.

MR. BARTON: That's very close to the shell.

MR. BONO: Very close to the shell. You can see the ring girder lines up with the support on the outside as a very rigid location combined with that condensation oscillation and the stress levels being concentrated. I think this picture is definitely worth a thousand words because it does show you just how close and how direct that impingement was.

MEMBER WALLIS: There was no damage to the HPCI pipe itself?

MR. BONO: There was no damage to the HPCI pipe itself or the penetration.

MEMBER ABDEL-KHALIK: So these corrosion areas are where the coating is bad?

MR. BONO: I'm sorry. Can you repeat that?

MEMBER ABDEL-KHALIK: What are these areas that indicate corrosion? Are these consistent with what you said earlier about failure of the coating below the water line?

MR. BONO: At least consistent with the areas we are monitoring now and the torus that we talked earlier below water. Those areas would be below water level.

MR. MOSKALYK: This particular area --

MEMBER ARMIJO: Pretty rusty.

MR. MOSKALYK: This particular area does not have significant enough corrosion that we're monitoring. We do not have pitting in this area where the HPCI discharges.

MEMBER ARMIJO: You've got a lot of rust there I think is the point.

MR. MOSKALYK: Surface.

MR. BONO: That's the question. With that amount of surface rust have we seen any blistering or thinning in that area.

MR. MOSKALYK: No metal loss in -- not enough metal loss in that area to monitor under the ultrasonic inspections.

MEMBER ABDEL-KHALIK: Is the coating intact in these areas?

MR. MOSKALYK: The coating -- you know, carbozinc 11 is a sacrificial-type coating over time so it's intact but eventually the zinc is depleted out of that coating system.

MEMBER ABDEL-KHALIK: Thank you.

MR. BONO: So under repair we did add the sparger during our last refueling outage. It does not direct toward the shell. It directs more into the torus area, torus and air space area. It has significantly reduced the loads. The next picture here is actually a drawing that we used as part of our design that shows the direction for the sparger.

MEMBER WALLIS: The sparger is a system of pipes with small holes in them or something like that?

MR. BONO: It's basically a pipe extended from the penetration with a pattern of holes.

Tom, if you can describe the analysis we went through.

MR. MOSKALYK: The hole pattern, they are one-inc diameter holes. They are about approximately three feet along the end of the pipe. The end of the pipe is capped solid. The holes are not circumfrencially. They are 30 degrees facing toward the shell and 30 degrees inward. It's solid. The holes are directed such that they will not impinge toward the shell.

MEMBER WALLIS: They are directed into the pool.

MR. MOSKALYK: They are directed into the pool. They are directed laterally along the access of the pool.

MEMBER ARMIJO: Your picture doesn't look like your drawing.

MR. BONO: The picture is --

MEMBER ARMIJO: The drawing looks wrong. I believe the picture.

MR. BONO: The drawing is after the repair. The picture is the condition that led to the failure.

MEMBER ARMIJO: So you actually changed the --

MR. BONO: We changed the design.

MEMBER ARMIJO: You cut that pipe out and made it prior to the changes.

MR. BONO: We cut it back closer to the

penetration and then sloped it with the configuration.

CHAIRMAN BONACA: Is there any history of similar problems in other BWRs as far as you know?

MR. BONO: We did not in our extended condition see similar failures at other BWRs but we did find other plants that had a steam design into the torus similar to ours so we believe they may be susceptible and we gave them that information.

CHAIRMAN BONACA: Issued LAR, I guess?

MR. BONO: We would have issued -- we in-opted containment when we determined that we could not meet our function, couldn't meet the containment function. We actually entered our emergency plan under an unusual event for an in-opt containment.

CHAIRMAN BONACA: Do you know if Pilgrim and Vermont Yankee are planning future --

MR. BONO: Pilgrim and Vermont Yankee are two plants that do have a sparger installed in their headset. One thing we did find as part of our extended condition. We looked at other ring girder gusset locations for the onset of the cracking.

We did find two other locations in that same bay that had the surface indications but nothing through wall. All those were paired during that outage and restored to code. The next picture actually shows where the HPCI line penetration is.

MEMBER SHACK: You just grind them out and you still had enough wall left?

MR. BONO: We ground them out and still had enough wall left and then did proper containment testing.

MR. PECHACEK: About three-eights of an inch deep is how far we went to fully excavate the flaw area.

MR. BONO: And I think we've covered these last few bullets but we did do the code repairs where we did find extended condition and we did analysis to confirm that the extended condition caused these flaws.

MEMBER WALLIS: Is this the end of your presentation?

MR. BONO: This is the end of what we --

MEMBER WALLIS: We have some questions about some other things but I wonder if we should take a break now. They are coming back after lunch. Aren't they?

CHAIRMAN BONACA: We can take a break if we want to and then they will have to be -- I mean, we are not going to switch to the presentation of the staff after we hear the questions and answers.

MEMBER WALLIS: I had questions about the weld overlays to the recirc system piping. You have a whole lot of weld overlays to the recirc system piping. It seems rather unusual. And I had questions about -- you haven't said anything about the steam dryer yet. Can we talk about the steam dryer after lunch?

CHAIRMAN BONACA: All right. If there are a few questions to go through, it's better to break now and then come back. We'll break until 5 after 1:00.

MR. BARTON: Just one other thing. We have the original research piping with overlays. That's what we're talking about?

MR. BONO: That is correct.

CHAIRMAN BONACA: Okay. So we'll take a break and come back at 5 after 1:00.

(Whereupon, at 12:04 p.m. off the record for lunch to reconvene at 1:05 p.m.)

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

1:05 p.m.

CHAIRMAN BONACA: We will resume the meeting now and there are a number of questions that the members wanted to raise. You had one.

MEMBER ABDEL-KHALIK: You showed us a picture, slide No. 33, for what you called surface corrosion on the torus. You indicated those are not the areas that were pitted. Do you have a picture of the areas that were pitted?

MR. BONO: We did not bring a picture of the areas that were pitted. Tom, I don't know if you can describe them. We can maybe verbally describe them. We did not bring a picture of those areas.

MR. MOSKALYK: The pitted areas there were actually some grids that were set up during the 1998 drain-down we replaced the suction strainers. We did a thorough inspection of the interior of the torus below the water line. What we had done is we sat up grids of areas of any kind of pitting. Any pitting of significance grids were set up and there were 10 areas of about three by three grids.

Those areas are the areas that are monitored. In 2004 nine of those 10 areas were routinely inspected once again. In 2006 we had done five of those areas. There is a priority of inspections for those areas but the pitted areas are in grids. They are three by three grids.

MEMBER ABDEL-KHALIK: What is the nature of the pits? What is the depth of the pits? What do they look like? What is the extent of the pitting?

MR. MOSKALYK: The depths of the pits, the more significant pits, the torus shell in that area is .632 inches. That's a nominal wall thickness for the shell. Our deepest pits to date we have a remaining surface wall of .566. We have a required general thickness of .503 inches. We have quite a bit of margin, a lot of remaining margin to the point of reaching the general minimum wall thickness for the torus.

CHAIRMAN BONACA: How do you select the specific areas you're monitoring? Was that selected because during the first inspection you find them to be the most serious?

MR. MOSKALYK: That's correct. Those 10 areas in the torus occurred over four different days, four of the 16 days, those were the areas where there was pitting significant enough to perform UT and monitor.

CHAIRMAN BONACA: Do you check any other

area in case you have some reason why pitting is initiated somewhere else?

MR. MOSKALYK: At this point we have all the data from 1998 for all the other areas but some of those areas are monitored. We have data for all the areas and at this point we are monitoring 10 areas.

MEMBER ARMIJO: What was the reason for the pitting in those localized areas? Was it breakdown of the coating or failure of the coating?

MR. MOSKALYK: Likely depletion of the coating. The coating does not blister off. It's just that over time it just waste because of the incompletion --

MEMBER SHACK: You get a localized failure so you concentrate.

MEMBER ARMIJO: Because if that's the cause of it, how do you know that it's not occurring somewhere else even now?

CHAIRMAN BONACA: That's why I was asking the question about do you ever look in some other areas.

MR. MOSKALYK: Well, you know, from 1998 we did a thorough map of the torus in that period. At that time 23 years in the plant operation you have a sufficient amount of time to establish areas that would be a problem.

MEMBER ARMIJO: So you are currently monitoring areas that had pitting as well as those that didn't have pitting?

MR. MOSKALYK: Monitoring areas that had any evidence of pitting.

MEMBER ARMIJO: But only the pitted areas?

MR. MOSKALYK: That's correct.

MR. PECHACEK: Just maybe a clarification too, though, is that we did increase the grid size so, again, the pitting is going to be very, very localized. Before we had grid that were one foot by one foot. Now we have extended those three foot to three foot area. We're starting to get some other areas and probably have a better profile if you do see attack going on.

MEMBER ARMIJO: After 1998 did you do anything like recode? I'm just trying to say whatever was initiating what the root cause was failure somehow of that coating. Did you do something to repair the coding and replace it?

MR. MOSKALYK: There was some underwater coating that was performed right before 1998 before one of the previous outages, one or two of the previous outages. There were some underwater coating repairs. It's a qualified underwater coating system that was used for some of the pitting. Since that time I don't believe that we have done any underwater coating on the pitted areas.

MEMBER ARMIJO: For example, when you drain this thing down here, it would have been dry and easy time to repair a coating if you needed to. Did you do anything like that?

MR. MOSKALYK: In 1998 I don't believe we had any extensive coating system.

MEMBER ARMIJO: Or since then?

MR. PECHACEK: Let me interject, Tom. There have been some areas specifically where we had the torus repairs because we removed a significant amount of coating to facilitate the repair. They were recoated.

MEMBER ARMIJO: But not in these --

MR. PECHACEK: Not in the areas where we observed the pitting. Again, we are keeping track of the approach rate and we have expanded the sample size with UT so roughly a three by three grid.

MEMBER ABDEL-KHALIK: Even with three by three that is still a very, very small fraction of the total surface area.

MR. PECHACEK: That is a correct statement but we would expect the areas where we had pitting initially that you would continue to have the same pitting rate there.

MEMBER ABDEL-KHALIK: Since you did nothing to mitigate it.

MR. PECHACEK: That is correct. Also as Tom, I think, stated previously, we do have several data points now so we have a remaining service life value that we have confidence in. As we get more information we can feed it back in.

MEMBER ARMIJO: What's hard to understand is if you had pitting it was caused by some defect in the coding or else it shouldn't have pitted.

MR. PECHACEK: Correct.

MEMBER ARMIJO: You didn't mitigate it at all and your UT data indicates that the pitting penetration rate has slowed down or stopped or something without any mitigation.

MR. PECHACEK: Can you address the rate, Tom?

MR. MOSKALYK: The penetration rate is quite small. On average it's about .0032 inches per year. Just as an example, in order for us to take the worst-case pit and reach the end of general life based on general wall thickness the year 2028 would be the time. We have about 21 years of service life left to reach general thickness of the shelf. That is not considering local putting. This is just for general corrosion. It's a very conservative number.

MEMBER ABDEL-KHALIK: But that's within the period of extended operation. Isn't it?

MR. MOSKALYK: That would be for general corrosion if we use the general corrosion equation. There is a code case N460 which is used for localized pitting. The localized conditions you can go lower than that if you need to but we very conservatively use the general corrosion rate and that's what our whole basis for our current inspections and our current program is.

MEMBER ARMIJO: I don't know. It seems kind of hard to understand why when you had this torus drained and dry it would have been a good time to just go and recoat those suspect areas.

MEMBER SHACK: This way he's got a leading indicator.

MEMBER ARMIJO: Yeah, well, you know.

MEMBER SHACK: Otherwise you would have to keep looking everywhere.

MR. PECHACEK: As Tom said, too, just for a clarification, the number, the 2028 assumes that worst corrosion rate was seen over the whole surface of the torus.

MR. MOSKALYK: That's correct.

MR. PECHACEK: If you're looking at localized, required values are going to be a lot or the values will be a lot longer. As we have opportunities whether it be during diving operations, we periodically look at the condition of the coatings. As we have those data points we'll take the necessary actions to mitigate it. Right now it's very, very localized, just a couple areas. Again, the values he provided were not even approaching middle wall.

MR. BONO: One thing to point out, the picture that you are referring to was actually prior to the ECCS strainer modification so this picture was prior to the mapping of the torus just to date this picture. The torus was inspected after this picture was taken.

MR. BARTON: And repaired where you found breaks in the coating or failure to the coating? If you look at this picture, I don't know what it is but it looks like pit marks and rush here and there. I wouldn't have shown this picture if I was you. It asks a lot of questions. It raises a lot of questions. It's a lousy picture of your torus coating system.

MEMBER ARMIJO: Yes, it looks pretty rusty and it's been repaired in spots or painted over or something.

MEMBER ABDEL-KHALIK: How would you guarantee that the sampling that you are currently doing in those areas is representative of what is going on over the entire surface area?

CHAIRMAN BONACA: As a minimum, I mean, I would like to hear that when you go in and monitor those areas it is also regional inspection of the rest. There are other areas with the same process that --

MR. BONO: It's probably worthwhile to describe the whole torus monitoring program visually. We do not drain the torus every outage but we do do above-water level inspections.

MEMBER WALLIS: But you do look at it.

MR. BONO: Right. We do look.

MEMBER WALLIS: What do you think about these rusty areas as you can see them?

MR. BONO: The water level in this picture would be right below the penetration. The rest of the line would be under the water level.

Maybe, Tom, just a general overview of

what we do for torus monitoring for coating.

MR. MOSKALYK: In general, every refueling outage we do send someone in. Actually a qualified ISI inspector is sent in. He looks at the water line and above the water line area and records the information and compares that every refueling outage to the previous outage.

MEMBER ARMIJO: And the UT measurements are made from the outside of the torus every outage or every few outages?

MR. MOSKALYK: Every outage since we established the inspections. Since 2004 we have been doing UT examination outside. We have a priority system set up for what locations would be inspected.

MR. PECHACEK: And, again, those areas -- just to reinforce the point, those areas were selected on the areas where we saw the most degradation as far as the pitting, the depth of the pitting.

MEMBER WALLIS: Is this a lower degree than what accumulates on the bottom of the torus? It used to happen in toruses but maybe it doesn't so much any more.

MR. PECHACEK: There is some silting. We saw that when we had divers in. They ended up picking it up with their fin.

MEMBER WALLIS: Do you clean it every outage?

MR. PECHACEK: Not every outage.

MR. BONO: We do an analysis of the content and then we do a de-sludge.

MEMBER WALLIS: So you see how much rust you've collected in the bottom there.

MR. BONO: Silting, dirt. We do have pictures of the 2005 torus repair that you can see the actual diver evolutions and you can see the clarity of the water.

MEMBER MAYNARD: I would like to go back to the drywell for just a little bit and make sure I understand. You've had no history of any leakage, bellows failure, no evidence of water getting between the liner and the concrete or nothing in the sandbed region?

MR. BONO: We have no history of leakage into the drain areas. That is correct.

MEMBER MAYNARD: What about on the floor? Do you have like a concrete floor?

MR. PECHACEK: The drain lines, if you can imagine this, people were questioning the purpose of it with a pedestal for the vessel. That area that is directly the torus is an open room. If you were to walk up underneath the torus to the inside wall, these drain lines comes out about 20 feet above the floor.

They are just out in the open so if there was something there, if somebody was in that area it would be obvious. In fact, the drain lines stop flush with the wall so you can get water on the wall and see any residual drainage that did occur.

Just another point that we didn't discuss before but the other thing that we did when we did do the boroscopic exams in 2007 is we actually formed a scan to see if there was any contamination that, again, would been assigned some kind of leakage curve and everything came out clean.

MEMBER WALLIS: When you do these exams you go all the way up in the hold area?

MR. PECHACEK: They did not go all the way up, no. They went up far enough to be able to see. I think due to the length of the probe and also trying to get through that torturous path they were just able to get up to the end of the drain line, see the stainless steel plates and look up above.

MEMBER ABDEL-KHALIK: Have you had any indications of recirc pump seal failures or leaks?

MR. BONO: We have had recirc seal leaks in the history of FitzPatrick inside the containment.

I don't have the timing or the number of those but we do monitor and identify leakage within our drywell.

MEMBER ABDEL-KHALIK: Along with that has the sump level indication ever failed?

MR. BONO: From my memory I'm not aware of a sump level indication failure. We have had cases where we've had sump level indication where due to either foot valve or check valve leakage we might be conservative in our containment leakage monitoring where we might count leakage twice because of back leakage through the systems. Maybe some of the guys from the plant staff can help me. I'm not aware of any sump level indication failures.

MEMBER ABDEL-KHALIK: I'm just trying to find out if there was any other sources of water.

MR. BONO: Recirc water would be inside containment.

MEMBER ABDEL-KHALIK: Right.

MR. BONO: Inside the shell.

MR. BARTON: You have a seal between the concrete floor and the drywell?

MR. BONO: We have a caulk seal that is inspected every outage.

MEMBER SHACK: What is the level of your identified leakage?

MR. BONO: We generally run less than 2.0 gallons per minute or gallons per hour. Because I'm standing in front of everybody now I'm losing my measurements here. We monitor that and our identified leak rate very small. We come out of outages generally with zero and then accumulate through a cycle but well within all acceptable limits. Most of that we can attribute the identified leakage to the normal design leak off from our research seals with our purge flow. Actually, when it gets too low we get concerned about our seal performance.

MEMBER WALLIS: Are you going to tell us about this recirc system piping weld overlays?

CHAIRMAN BONACA: Let me just go back to the torus. We had a long discussion and then we left it hanging there. I would like to just understand from you your perspective on what should make us comfortable that what you're doing or going to do as far as your program will give us good assurance over the next 20 years this torus will be functional?

Functional to me means that be capable of also taking the worst possible transients without failure. I would like to understand, you know, what are you doing to assure that. I understand this is part of the in-service containment program. Could you tell me?

MR. PECHACEK: I think the assurance is in the program that we implement. We have a program that meets the requirements. We do the monitoring. We do have some pitting but I think we are conservatively applying that to the whole torus and we are monitoring our analyzed life and will continue to monitor that and apply that to the torus.

I think the assurance I can give you is in our inspection program on the fact that we're being conservative. I understand the concern about not correcting the cause when we identified the pitting areas but we are applying that generally calculating surface life and we will take action before we reach any of our minimum wall requirements.

MR. PECHACEK: I think that sums it up well in addition to the items we discussed.

CHAIRMAN BONACA: Okay. But you limit yourself to the monitoring or the pitting areas but you able to look at in a broader sense other areas where you find that you have no new pitting areas that are developing there and you rely on your corrective action program to qualify or repair?

MR. PECHACEK: That is correct.

MEMBER ARMIJO: But if you had new pitting events happening elsewhere, would you find them? Would you spot them in your normal inspection of the torus?

MR. PECHACEK: We clearly would in the areas where we are currently performing the reviewing in the three by three grids.

MEMBER ARMIJO: The pits that are there now you found them by some method. Somebody saw something.

MR. PECHACEK: Yes.

MEMBER ARMIJO: I'm just assuming that the same thing would be visible if the pits were occurring somewhere else in the torus.

MR. PECHACEK: I'm going to ask Tom Moskalyk to correct me if I misstate something. Those original pit depths were taken in 1998 when the torus was drained down so you literally had people with pit gauges walking through the torus saying, "Hey, here is something here," and taking measurements. They were actually measurements in a dry torus.

MEMBER ARMIJO: Well, that's the way they were found.

MR. PECHACEK: That is correct.

MEMBER ARMIJO: If there was other pitting going on now and the torus is flooded, you wouldn't find them.

MR. PECHACEK: We would not unless we had other ancillary activities. As I mentioned, when we had the divers in for doing the extended condition review on the torus flaw, if there was something notable, they would bring it up. Additionally just the areas outside of the grid.

MR. BONO: And in that extended condition flaw review we did have to lower level to address some of those extended condition locations. When that lower level becomes exposed, then that is inspected.

MEMBER ABDEL-KHALIK: But those divers don't go around with a depth measure.

MR. BONO: No, but it was inspected by our qualified staff when we lowered the water level.

MEMBER ABDEL-KHALIK: I guess we are kind of worried how you can be comfortable that there isn't some pitting or degradation going on elsewhere in the torus when the only way you found it initially was when the torus was drained down and conditions were ideal for finding something. You will eventually find it if it's there but it's going to be painful.

MR. SMITH: If I may, this is Art Smith. One of the things that we also looked at is that we found those pits visually and then we've been monitoring them. We had quite a few data points as far as the depth of those pits and it's rate. Even if there is some initial or new pits that do occur, the rate is not going to be greater than what is already known.

MR. PECHACEK: Art is our ISI program owner. He's unable to be with us today.

MEMBER SHACK: But they monitored the worst locations and you assume you bounded everything else. They think they are looking at the worst locations.

MEMBER ABDEL-KHALIK: Only if you understand the underlying mechanism.

MEMBER SHACK: If it's a defect in the coding, then they found the first defects and presumably they are the worst defects.

CHAIRMAN BONACA: Do you drain down the torus with some frequency? I mean, every 10 years, 15 years or whatever?

MR. BONO: Tom, are you aware of any required scheduled periodic --

MR. MOSKALYK: Not that I'm aware of.

CHAIRMAN BONACA: I didn't get the answer to that question.

MR. BONO: No, we are not aware of any

required scheduled periodic drain down.

MEMBER SHACK: Historically you drained it to put in the sump strainers?

MEMBER ABDEL-KHALIK: It's the HPCI.

MR. BONO: We drained it to put in the sump strainers. The actual repair for the HPCI exhaust we did not drain it. We did have to lower the level to do the extended condition repairs.

MEMBER SHACK: So in history we've had one drain.

MR. BONO: In history in my knowledge we've had three drains.

CHAIRMAN BONACA: I guess the situation is similar to other BWRs. There is no requirement for drain down.

MR. MOSKALYK: We have had three drains of the torus. Two were in conjunction with the Mark 1 program upgrades. The third was for the ECCS suction strainers.

CHAIRMAN BONACA: I have no further questions. Any other questions?

MEMBER WALLIS: Can we move on to something else?

CHAIRMAN BONACA: Yes. Now you can.

MEMBER WALLIS: You were going to tell me about all these weld overlays to the recirc system piping, why they were necessary and are they going to continue at the same rate and so on.

MR. PECHACEK: What I would like to do is Artie Smith is on the phone. Artie, if you could give us an overview. Did you hear the question?

MR. SMITH: Yes, I did. I'm prepared. Right now FitzPatrick has 24 overlays. Of those 24 overlays two of them were on the jet pump instrumentation line and one is on our CRD cap line. All of those overlays were found through ultrasonic testing and/or cracking and subsequently overlaid over a period of time beginning back in about 1987. There might have been one or two that was prior to that but that's what those overlays mean.

What we are actually currently doing as far as our research system and all our stainless steel at FitzPatrick is we are inspecting that in accordance with performance demonstration initiative and with the qualified inspectors equipment and procedures. Right now we feel that we have a very, very good handle on the status of these welds. We have a high degree of confidence as far as the quality of the examinations that have been conducted.

MR. BARTON: When was your most recent

overlay?

MR. SMITH: That was the CRD cut cap.

MR. BARTON: When?

MR. SMITH: That was the CRD cut cap which occurred RO14. I'm not sure what date that was.

MR. BARTON: You've had none on recirc piping recently?

MR. SMITH: No. No, we have not.

MEMBER WALLIS: There were 21 --

MR. SMITH: Excuse me?

MEMBER WALLIS: There were 21 overlays on the recirc piping?

MR. SMITH: Oh, yes, 21 overlays on the recirc piping and then three --

MEMBER WALLIS: Why so many --

MR. SMITH: Two on the JPI and one on the cut cap.

MEMBER WALLIS: Those cracks all occurred at one time and there is no more cracking since then?

MR. SMITH: No, they didn't all -- they weren't all found at the same time so I wouldn't make a statement that they all occurred at the same time.

MEMBER WALLIS: So they have been occurring over the years?

MR. SMITH: That's correct.

MEMBER WALLIS: Did they stop or something? What happened?

MR. BONO: Artie, can you explain the last research system weld overlay that FitzPatrick has had.

MR. SMITH: Okay. The last one we had -- let me just find that. I believe that was in 1990.

MR. BONO: The 21 recirc overlay and, Artie, you can correct me, occurred between the period of the late '80s to 1990. We have not had a recirc since then.

MR. SMITH: That is correct. We haven't had a recirc since 1990.

MR. BARTON: So what are you doing different that is precluding new cracks?

MR. SMITH: Okay. We're doing a couple of things. We are currently on hydrogen and noble metals. We actually performed IHSI on all the welds other than our category D welds. All of the welds have been stress improved so we have the mitigating aspect of that that we are also applying.

MEMBER ARMIJO: When were those IHSI treatments done?

MR. SMITH: Actually 1987/1988. That's when the vast majority of cracking was found.

MEMBER ARMIJO: Some you mitigated with

IHSI and some you mitigated with overlays. Since then you've been on hydrogen water chemistry and noble metals.

MR. SMITH: We started hydrogen --

MEMBER ARMIJO: 1988 according to your chart.

MR. PECHACEK: That's correct.

MEMBER WALLIS: So the problem would appear to have been arrested so it's not a concern in the future. That's really what you're saying.

MR. SMITH: That's correct. We believe they are arrested. We are continuing to perform the exact same procedure to ensure that is the fact.

MEMBER SHACK: Are your overloads inspectable?

MR. SMITH: Yes, they are. All of them are in accordance with the PDI.

MR. BARTON: I don't have anything else.

MEMBER WALLIS: How about steam dryers? We haven't discussed steam dryers yet.

MR. PECHACEK: I can address steam dryers for you. Just a couple things. I'm just going to briefly go through history, provide the status as far as where we are now rather than if you have any questions. Again, just in the form of a timeline which makes it a little bit easier.

We did have 10 indications that were identified in our RO14. That was in the year 2000. These are in the upper areas of the support ring, near the upper support ring specifically. They were found as a result of visual inspections.

In the fall of 2004 we completed the GE service information letter 644, supplement 1, required inspections. We found some relevant indications as I mentioned a couple of hours ago in these vibration blocks. There are actually mounting pads on the top of the dryer.

Also last outage we noticed a discrepancy on a previously documented indication, again on the vibration blocks. We went back to look at the tapes and found out that indication was present the previous outage and was mischaracterized. As I mentioned before, we also found an indication in the upper southwest corner of the dryer at an intersection between a horizontal and vertical weld. All the previous indications were in the heat affected zone so it's reasonable that they are IGSCC.

MEMBER WALLIS: When you say indication, what does that mean?

MR. PECHACEK: It means something that met the criteria and that it wasn't something that was resolvable so it was a crack.

MEMBER WALLIS: Is this a little crack or a big crack?

MR. PECHACEK: They vary. The 10 that I mentioned in the support ring were small. The ones on the vibration monitoring blocks, the blocks are nominally about three by seven. In some cases the indications are up to about 50 percent of the perimeter. We did perform a flaw evaluation to determine if there --

MEMBER WALLIS: What did you do with that?

MR. PECHACEK: They are left as is. We did a flaw evaluation to determine if we had enough remaining ligament. Just to give you an idea, I think the bounty analysis was remaining ligament that was required.

MEMBER WALLIS: You just keep watching and when it gets to 70 percent or something you do something?

MR. PECHACEK: We are also looking at having contingency repairs available. Just to give you an idea as far as the allowable cracking, as long as we have a remaining ligament of about two and a half inches so, again, these are not in the flow path.

These are just on the top of the dryer.

MEMBER WALLIS: There is indication that something is going on.

MR. PECHACEK: Yes. It's intergrading with stress corrosion cracking.

MEMBER SHACK: Are they growing under the hydrogen water chemistry?

MR. PECHACEK: We have not seen any growth over the past two outages. What I wanted to mention was we had to recharacterize one of the cracks that was not properly characterized during the previous outage. The ones in the vibration blocks have been studied during the last couple of outages.

MEMBER SHACK: So they do appear to be IGSCC rather than fatigue?

MR. PECHACEK: Yes, absolutely. They are in a heat affected zone of the weld which is typically indicative of --

MEMBER ARMIJO: It's kind of strange, though, because the steam dryer is supposed to be dry steam and IGSCC requires a liquid environment to have electrolytes so how can you be IGSCC if you don't have any water up there?

MR. PECHACEK: That's a good question. I can follow up on that. I don't have a response on that.

MEMBER WALLIS: There is some water up there.

MR. PECHACEK: Yeah, there's some. It's not sitting water.

MEMBER WALLIS: It's probably on the surfaces. It's damp on the surface. The steam isn't completely dry.

MR. PECHACEK: Wet/dry steam.

MEMBER WALLIS: Wet steam. Are you monitoring any kind of oscillation vibration, acoustics or anything? No monitoring of what is happening up there?

MR. PECHACEK: There was no monitoring for the dryer for the vibration.

MEMBER WALLIS: So you have a dryer that doesn't shake unlike some of the other dryers?

MR. PECHACEK: Again, Steve mentioned previously, Bono, any uprates have been small values. We are operating under the original design of the dryer. What I would like to mention, only because it was brought up before, is the one we found in the southwest bank, the upper areas of the dryer. It's about four inches long. That one was a little bit different.

It was not in a heat affected zone. It was directly across the middle of the weld. We had the NSSS provider form an analysis on that before we removed it and they determined that the weld was actually undersized. Again, it was due to fatigue but it was due to an undersized weld. There is a stiffener plate, vertical and horizontal that comes across. It had originated from the toe of the intersection and it ran about four inches across the wall.

MEMBER WALLIS: So the assurance you give us is that you are monitoring things and inspecting things sufficiently to detect anything that goes wrong in the steam dryer?

MR. PECHACEK: That is correct.

MEMBER WALLIS: Every outage you do this?

MR. PECHACEK: Yes, we do.

MR. MEDOFF: Dr. Wallis, this is Jim Medoff. To address the aging of the steam dryer, we recommended that they put a commitment to use VIP point 39 aging management criteria inspections and flow evaluation criteria to manage it and degradation in the dryer. That commitment is in place. The commitment includes that they are going to use the NRC approved version of VIP .39 which is currently under the last stages of review.

MEMBER WALLIS: You are reviewing that now?

MR. MEDOFF: The Division of Engineering is reviewing the report.

MR. BONO: Anymore questions?

MEMBER SHACK: How big are your cracks in the vertical weld to the shroud?

MR. PECHACEK: One moment.

MEMBER WALLIS: You have tie rods. Don't you?

MR. PECHACEK: We have 10 tie rods. We are pulling out the paperwork here if you would like to entertain a different question.

MEMBER SHACK: Is there any cracking in your top guide?

MR. PECHACEK: No cracking has been identified in the top guide. Again, we perform those inspections as we have. Cells evacuated during refueling are 10 percent.

MEMBER SHACK: How do you decide when to renew the noble metal? GE recommendation or --

MR. BONO: It is a GE recommendation based on the depth and how long you can anticipate the depth of the metal. I think we're at a every two cycle application now but I would have to look for confirmation of that.

MEMBER SHACK: You actually monitor an electrochemical potential?

MR. BONO: We do ECP probe monitoring that confirms the analysis.

MEMBER SHACK: Is that online most of the time?

MR. BONO: We have had pretty good -- I would have to get confirmation of its reliability but unless one of the technical guys, Larry or anybody is aware of the reliability of the monitoring. I'm not aware of issues with it being -- I can follow up on that and we can get that information.

MR. PECHACEK: Let me just, again, back to the core shroud. The question was what is the extent of the cracking. I have two examples I'll provide. These are weld CRV5A and 5B. Those seams are approximately 90 inches in length.

Addressing the 5A first, 13 indications that the total crack length and, again, this is an aggregate from the smaller cracks, about 32.4, the longest uncracked ligament.

MEMBER WALLIS: Inches?

MR. PECHACEK: Yes, sir. The longest

uncracked ligament was 30.5. No through-wall. Maximum depth was 47.2 percent of wall and wall thickness is minimum 1.5. It just gives you a general idea. Actually, I stand somewhat corrected. The weld length is supposed to be 100 inches. We were able to actually use T-scan almost all of it, about 95 percent. The other one is very similar.

MEMBER ABDEL-KHALIK: You indicated what the longest uncracked ligament is. What is the shortest uncracked ligament?

MR. PECHACEK: The shortest uncracked ligament. Again, I'm going to do this by deduction here only because of the way the dimensions are set up. It appears to be that we have one instance in the CRV5B where it's going to be close to two inches. Again, these are welds -- excuse me, indications on either side of the weld in the heat affected zone. That's about two inches.

MEMBER ARMIJO: You've been monitoring these cracks over a period of time.

MR. PECHACEK: Yes, we have.

MEMBER ARMIJO: Is there any indication that these cracks are continuing to grow even though you are using hydrogen water chemistry or is there an indication that they have been arrested, they are not growing?

MR. PECHACEK: We touched on this briefly before. Our shroud design is fairly unique with 10 tie rods and presents a huge challenge as far as getting UT scopes and small cameras in the area. One of the reasons we went with UT last outage was the fact that we had inconsistent validation from the outage with the visuals.

Some of the numbers would be less than they were previously. Now we had a new baseline with UT. We have seen no noticeable growth but now again we have a baseline that's going to be a lot stronger than the visuals because things that were scratches we were considering indications before. We just couldn't get the visual acuity.

MEMBER ARMIJO: As far as loading for an actual crack to grow, is there any loading mechanism other than residual stress?

MR. PECHACEK: I would have to look. I don't know if George Rorke can help with that.

Loading during axial on the shroud, George?

MR. RORKE: You mean accident?

MEMBER ARMIJO: No, axial load.

MR. PECHACEK: Axial load.

MEMBER ARMIJO: I mean, what's the loading to make an axial crack grow in the shroud other than residential stress?

MEMBER ABDEL-KHALIK: With that baseline information, you say this information will serve as a baseline starting point information?

MR. PECHACEK: Because these are UTs that we didn't have before previously.

MEMBER ABDEL-KHALIK: How frequently will you check?

MR. PECHACEK: We will be going back to the shrouds every outage.

MEMBER ABDEL-KHALIK: With that level of detail?

MR. PECHACEK: In some cases we may not be doing UTs. We may be doing visuals since we have a better picture as far as what to look at. Again, we were very, very challenged for our analyst to be able to get a proper characterization of indications in the shroud so the one-time UT -- and we'll make a decision going forward whether or not we have visual or even follow-up UTs in some cases.

MEMBER SHACK: The UT can't come from the inside of the shroud?

MR. PECHACEK: It could. Obviously we

could clear it out. We can also get it from the OD. Yeah, that's another option but it's a matter of putting in enough cells to be able to work all the way around.

MEMBER ARMIJO: In the core there.

MR. PECHACEK: As bad as the ID access is, it's still better.

MEMBER SHACK: Eight inches to the wall of the vessel and eight inches to the --

MR. PECHACEK: Okay. Anything else on that?

CHAIRMAN BONACA: Okay. Any additional questions for the licensee? Not at this point? Then we thank you for your presentation. It was very good and we turn to the staff for the staff presentation.

DR. KUO: Tommy Le will be leading the staff presentation and Glenn Meyer is going to present to you the inspection findings. Before they do that, I would like to correct my answer to Dr. Wallis' earlier question about whether there is any practical experience with fatigue cracking.

I was sitting there in the morning after the answer and trying to think hard. Around 1988 time frame there was a safety injection line crack at the foley. The new cause of that cracking was the thermal power. Because of that we issue an IE Bulletin 88-08. That came to my mind.

MEMBER WALLIS: I think there was some incidents in Japan as well.

DR. KUO: Correct.

MEMBER SHACK: Well, there is thermal fatigue in Japan and France and your steam generators, pressurizers.

DR. KUO: When I answered the question I just didn't think too far.

MR. MEYER: All set?

MR. PECHACEK: Yes. Thank you.

MR. MEYER: You're welcome.

MR. SMITH: Hello, Joe. Are we done?

MR. PECHACEK: That's a tough question. Stay on the line for a moment.

MR. LE: Good afternoon, Chairman Bonaca and distinguished members of the subcommittee. My name is Tommy Le. I'm the project manager for the staff review of the FitzPatrick license renewal application. Up here I have Glenn Meyer who is the inspection team leader from Region I and Rich Conte who is the branch chief for Region I engineering support branch.

With me I have Jim Medoff over there.

He's the assistant audit team leader. Roy Matthew was the team leader but he's on leave this week so he had asked me to make the presentation and the result of his audit. The assistant team leader will keep me honest in my presentation. With me I have Ken Howard who is my OPM doing a review of the FitzPatrick.

The last time I was here I was a PM and everybody think that I should have a permanent office in upstate New York, especially in the winter time. Last time there was 12 foot of snow and they declare National Guard out.

MEMBER WALLIS: That's more than 50 pounds per square foot. Isn't it?

MR. LE: Well, with that introduction, I would like to also tell you that the SER that you looked at last month was a product of all my colleagues back here from NRR, the audit team and the Region. I had nothing to do with it. If you find something wrong, it's their fault.

MR. BARTON: It was too thick.

MR. LE: We get paid by the pound. Anyway, I also lastly would like to thank the applicant and technical and management personnel who have supported us during the audit and the staff review. We have RAI and audit questions back and forth.

With that, I would like to say that it is my honor to represent the staff to present to you the result but I know with that thick document you all have read it last night.

I will provide an overview of the plan and the application and the follow-up discussion of the scoping and screening results. After that Glenn Meyer will talk about his inspection and what he found in the field. Then I will talk about the aging management and I will end up with TLAA conclusion.

Under this first slide you are seeing some of the information regarding the plant that the applicant had provided you earlier. FitzPatrick nuclear plant expires October 17 of 2014. A lot of this information I have put on the slide have been covered earlier. I will go to the next slide, No. 4.

We have received the application on August 1st. The staff start running with the review. However, the application was sent in and then the applicant followed up with an outage so there will be snow in the background because they come in winter so we worked with the audit team to arrange a different day to make sure that every i is dotted and every t is crossed during the outage review.

There are two open items in SER. One is PT cool dimension on metal fatigue problem and the fluence calculation. You heard this morning that the applicant had already done the recalculation they do in QA so that they can reconform to 1.190 which we had rejected the first time.

Slide No. 5, the results of the NRR --

CHAIRMAN BONACA: Before you move on to that --

MR. BARTON: License condition.

CHAIRMAN BONACA: I had another question. What do you mean by 83 percent consistent with GALL report?

MR. LE: 80 percent of the report we're talking about the consistency. The applicant had -- six of them to be exact.

CHAIRMAN BONACA: Six are consistent, 20 are with exceptions or enhancements, and a bunch of them are plant specific. When I look at those numbers it seems like 83 percent is pretty optimistic.

MR. LE: We more or less looking at the consistency even though with enhancement exception.

DR. KUO: I'm sorry, Tommy. How can you say with exceptions you can say it is consistent with GALL? I mean, I think what we meant here is that those programs that are either 100 percent with GALL or consistent with enhancements. Those two categories that are consistent account for 80 percent.

CHAIRMAN BONACA: I didn't find any problem really generally with the exceptions. I mean, the fact that they were accepted but there were a lot of exceptions. I'm just trying to understand how you measure 83 percent because they must have a meter there that is very good.

MR. LE: For every exception the staff also sit down with the applicant, engineering, and management and seeking the reason why they seek exception from the GALL.

CHAIRMAN BONACA: I understand that. I was just talking about the 3 percent. I'm glad there are no decimals.

MR. LE: You brought up a good point. During out first day or two of the audit we didn't see the personnel involved heavily during the response of the question. The corporate influence was very strong. After the first day and a half we had a meeting with the applicant management including vice president and say that we would like to see more response from the personnel because some of the questions we asked we had to ask a different way to get an answer.

From that day on on the second day and third day for every meeting we had the management was there and the right technical engineer was there and it was well responded. We did point out there is a local sheriff there, the vice president. We need to talk to the local engineer at the plant and we did have that. The next slide --

MR. BARTON: Whoa. The three license conditions are?

MR. LE: The three license conditions are the standard license conditions. One is implementation of the UFSAR.

MR. BARTON: Okay. Right. I gotcha.

MR. LE: There is nothing unusual here.

MR. BARTON: Okay.

MR. LE: Slide No. 6 is audit team determined that there is no omission in the system structure in the scope of the license renewal when we look at Section 2.1. The same way, no omission at Section 2.2. As I said, we review about 57 mechanical systems and out of which we had 26 BOP system. All were reviewed 100 percent by both the technical staff, NRR, and some also supplemented by the review by the audit team.

We also find out in the BOP there are some miscellaneous system that the staff would like to devote more on the system that is more significant so we call it tier 1 and tier 2 review which began at Brunswick. In the application there are 18 sub-systems that are not significant but it might impact the safety system if it goes wrong.

In the mechanical system the staff had brought into the scope some additional components we show in the next slide and those things that we found and applicant amend the application.

On slide No. 9 when we looked at Section 2.4 and 2.5 the staff found no omission in accordance with the regulation that we will follow. On slide No. 10 the staff had now determined that the applicant had complied with the scoping methodology and they meet the requirement of 10 CFR 54.4 which is scoping.

On slide 11 we now come to the portion where the Region had come in and become our eye and ear to look at the application. I would invite Richard and Glenn to entertain at this time.

MR. MEYER: Good afternoon. I'm Glenn Meyer. I lead the regional inspection team at FitzPatrick and I would like to discuss the results. This is an appropriate time to talk scoping and I apologize because I don't have a specific slide to help the process but I would like to cover Pilgrim, Vermont Yankee, and FitzPatrick as I did the scoping at the three places.

What I found is that Pilgrim was inspected in September of 2006, Vermont in February 2007, about five months later, FitzPatrick in April 2007, two months after that. The applications were submitted basically concurrently. What did I find when I looked at scoping?

Let me step back for a second. The job basically is to identify what the boundary is. We are looking at the A2, the nonsafety part. The application doesn't do a good job of calling out that boundary but it does cover the types of components, material, environments, and things like that. There is a lot of information but getting to the bottom of what's the boundary is at times difficult.

At Pilgrim it turned out that -- there is basically two areas, structural interaction and spacial interaction. Structural, are nonsafety parts that are depended upon for the seismic design, and spacial, are there fluid in the vicinity that could affect safety-related components.

At Pilgrim I found that the structural

interaction was flawed in that they had made a misinterpretation of what information was on the drawing. They believed that the drawing showed the boundary of the seismic design. That wasn't, in fact, the case. They agreed when I was able to show them the error and they took approximately a couple months to go back and look at what it should be.

They got some operationally knowledgeable people involved to go out and walk down the particular areas. I came back in a few months to look at what had been done and found that they had done a credible job of correcting the problem.

At Vermont Yankee the problem was in the spacial area. In A2 they tend to lump together. The safety-related parts are called out system by system. In going through the A2 part I noticed that the turbine building was not included. My experience is that there is not a lot of safety-related components in the BWRs in the turbine building but there is enough and they are not certain as to where primarily the reactor protection system cabling runs.

For conservative purposes and ease of analysis they just lump most of the turbine building in. Vermont Yankee had called out only three areas that needed to be in scope. When I went to look at them they were inaccurate in terms of what was there and what it meant. They have attributed that to problems in the database. They did quickly call their compatriots at FitzPatrick and Pilgrim found that the turbine building had been included so they agreed to do that at Vermont Yankee.

There were some documentation issues in the structural area. At FitzPatrick the problems were just minor and isolated and they were corrected by a license application amendment. I hope that clarifies the scoping.

CHAIRMAN BONACA: First of all, let me say that I truly appreciate the inspection report more and more for the license renewals is becoming the mainstay because you do identify problems. It's disconcerting when we have to make a statement that we feel confident that scoping systems have been identified because often times we have to rely on your inspection.

MR. MEYER: That gets to the --

CHAIRMAN BONACA: Let me ask a question. The question is essentially I feel comfortable now that you have done the inspection and I am impressed by what you have found at Vermont Yankee. What gives me comfort is that something else out there hasn't been totally missed.

MR. MEYER: Vermont Yankee or FitzPatrick?

CHAIRMAN BONACA: No, FitzPatrick. We talk about the three units because it is the same team and it is an experienced team, too.

MR. MEYER: Right.

CHAIRMAN BONACA: There have been issues that undermine a little bit the confidence that, in fact, the systems have been properly identified.

MR. CONTE: I think you heard the licensee talk about an extent of conditions that review. They were convincing to me but this isn't the end of the story. We still have the commitments inspections. By rule they will need to demonstrate that managing the effects of aging and the scoping issues will still be compliance issues. This isn't the end of the story. We'll be back to look at the new programs, the modified programs.

DR. KUO: Dr. Bonaca, Bill Rogers of the staff is going to make some comments on scoping. He's the team leader for staff scoping audit. His comments are going to be focusing on FitzPatrick only. We are not talking about Pilgrim and Vermont here.

MR. ROGERS: Hi. I'm Bill Rogers. I work in the Division of License Renewal. I was a team leader for the scoping and screening methodology audit. Before I speak specifically about Fitzpatrick results, I would like to say in general that the A2 scoping is a somewhat complicated issue for the applicant. It actually has three major pieces to it that the staff uses to do its review.

Probably the first initial piece would be the scoping and screening methodology review some of which we do in the office and some of which we do during the onsite audit which we performed as Tommy mentioned earlier.

Following that DSS does a review themselves. Quite a bit of the A2 information they are able to evaluate through the documentation they receive from the applicant and additional information that we gather onsite. We can provide additional insight to the process as used by the applicant. We also use the RAI process to gain additional information that we need.

A third piece of that is the regional inspection. Regional inspections are very useful particularly in the area of spacial interaction which as in the case of FitzPatrick was done on a room basis where they bound the areas to identify safety-related equipment in the area and then they can identify the corresponding nonsafety-related equipment that will be needed to be brought into scope for A2.

When the applicant does it, this is typically done through a combination of database information and onsite reviews, room walkdowns. During the regional inspections the regional inspectors can interface with the applicant to determine whether they agree. They can do independent inspection of the equipment in the room to determine that.

In the case of FitzPatrick during the methodology audit we didn't find any irregularities that would raise to the level of an RAI so that we would need additional communication on that subject. In fact, that was one of the few plants where we did not have a request for additional information in the area of A2.

CHAIRMAN BONACA: I am confident that the methodology is correct because so much has been done already and people have been comparing the methodology from plant to plant. It's more the implementation part. The reason why I ask that question is we typically in our letter make a statement that says that we are confident that the licensee has identified the components and scope. When we have events like this, you know, then I ask myself what gives me the confidence. That's why I turned the question to you.

MR. ROGERS: Mr. Bonaca, may I add something, please?

CHAIRMAN BONACA: Yes.

MR. ROGERS: I would also like to add that in a general sense that when we are doing our A2 review for various applicants, there is often additional equipment brought into scope as part of all three portions of the review. It could be during the methodology audit, it could be during the DSS review, and it could be identified during the regional inspection.

It is not uncommon to bring in additional equipment. Sometimes it's a matter of timing during the process of the application review which may highlight the event as opposed to the actual bringing of the equipment.

MEMBER MAYNARD: From what I see it seems like the big ticket items, the big safety-related items. There's very little controversy on that. It's kind of the further that you get away from that and I would suspect that if you sent two different inspectors out who haven't worked together before to take a look, they may come to some different conclusions when you get into some of those fringe areas there.

There may be an issue that I don't know if it needs clarification or whether we just recognize that on the fringes there's always going to be some gray area out there. But to get it totally consistent I think the NRC staff would have to refine their guidance and provide --

CHAIRMAN BONACA: I think what is happening is that the inspectors like Mr. Meyer, I mean, he goes from plant to plant in Region I and looks at it so he gets a level of knowledge that goes beyond --

MR. BARTON: You learn from one inspection to the next.

CHAIRMAN BONACA: I don't have a problem with that. It's just simply that when we talk to the full committee we will hear requests from some members who will say, "What gives you the confidence?" That's why I wanted to explore the question.

MEMBER MAYNARD: I believe -- again, I agree. I think Mr. Meyer learns and does a good job. I'm not sure if you had an inspector from Region III or Region II. They may do an equally good job but I'm not sure you would come up with the same ultimate scope in the thing. I don't think that's necessarily a problem. I don't think it means that the licensee necessarily did a bad job. I think we are always going to be dealing with some of these gray areas on the fringe out there.

CHAIRMAN BONACA: It's unlikely we would ever raise this issue, although we hear that something has been added. I'm raising this issue here because for Pilgrim it meant the significant -- for Vermont Yankee it meant the significant change. I mean, changes to 36 tables, changes to I don't know how many new systems added to the scope. I mean, it's a big thing so it wasn't minor. That's why I raise the question.

MR. MEYER: I would like to talk to two factors in this area and those are we've talked about the interplay between the corporate license renewal approach, that knowledge, and the plant specific knowledge and how well they interface. I think Entergy has alluded to the fact that they want to do a better job of having plant specific people involved. I think that was certainly part of the problem.

There was another factor and that is the drawings. The drawings are not a specific requirement but it has evolved to the point where it's a useful took in the application. Entergy chose as part of their application to not show the A2 systems on the drawings so the drawings become basically a partial tool. To find out about the A2 part, you have to pursue it system after system, go in the plant, try and understand.

I'm optimistic that is part of the fix that they will use and in the future the drawings will show that. Most of the drawings that I've seen in the past have included both A1, the safety related, the A3, the regulatory required, and the A2 shown. Time will tell.

As to the NRC, I have to say we also can do a better job of this interplay between the corporate knowledge and headquarters and their understanding of the licensing basis and the field application and our familiarity with the plant.

What has tended to hinder that is the headquarters scoping effort is the first thing that goes out and the regional review tends to be the last thing that goes out so it can be a considerable time period between the two. We are endeavoring in the Indian Point case and I'm going to join the scoping effort at the beginning so we can share our special areas of understanding.

I'm also somewhat reluctant to admit that I'm getting the choice assignment of going to Wolf Creek next week to help Region IV with their --

MEMBER ABDEL-KHALIK: Is there a generic problem with recordkeeping so that design changes that have taken place over the years somehow we don't have the design basis or the supporting drawings?

MR. MEYER: I would say not so much the design basis in recordkeeping. It's the database from construction that they inherently want to use to the extent that they can and they vary considerably. Now, I think they have alluded to in different meetings they use the database. I don't have that limitation. I just go out and see what the result is. Apparently trying to use the database can be difficult. These are databases from 30 or 40 years ago. A lot of times they have significant limitations.

MEMBER WALLIS: How much of this is computerized and how much of it is paper records? If you've got a drawing this is on the computer and if you want more detail you can magnify places or add stuff or would you have to go and look in drawers and find bits of paper?

MR. MEYER: The license renewal application drawings tend to be recent. They have modified previously drawings and they have highlighted them and they are in electronic format. The construction drawings frequently if they are not used for operational purposes a piping and instrument type drawing.

MR. MEYER: They are all papers in drawers somewhere.

MR. MEYER: A lot of it, especially --

MR. BARTON: Be careful. In files. In files.

MR. MEYER: I mean, you tend to see that in the drywell monitoring because how was the system constructed, the drains, the pipes, the flow switches, a lot of times that wasn't readily available.

DR. KUO: Dr. Wallis, along that line we are trying to really standardize everything so what we are doing right now is trying to create a database from our past reviews. The 48 licenses that we issued we are trying to go back there and trying to attract the data out and to prepare a database.

MEMBER WALLIS: You mean that you don't sometimes know just where the pipes are in the whole system in some of these auxiliary piping that maybe feeds some service water over some obstruction and goes to something else? In order to find out just where it is you have to go and look at it in cases like that?

DR. KUO: There are some spacial situations that the walkdown of the plant would really help. That is the reason why just about a year or so ago we changed the review process for A2 situation. We requested the region to help us to do that because we realized that in some situations the spacial relationship is important and a regional inspector can certainly do a better job than the headquarter reviewers. We are working together at headquarters and region to try to get this done as best we can.

CHAIRMAN BONACA: You know, I was looking at the amount of weeks you spent doing that within the region and headquarters and I'm impressed. I mean, it's a lot of time. Many weeks.

MR. MEYER: I will say in Entergy's case at FitzPatrick they did have somebody that was knowledgeable about the plant and knowledgeable about the license renewal process that if I had questions I went in with that person and they were able to relate to what was in and what wasn't and what the system was. It was clear that the interface was a lot more effective.

MR. BARTON: Most people use system

engineers?

MR. MEYER: In the engineering organization. At Pilgrim and VY I tended to -- they sent me out in the field with a system engineer but he hadn't been involved in the license renewal process. He could explain what the system was in the pipe but, "I can't really tell you if that's in or out." You need both.

On slide 13. In conclusion, at FitzPatrick the spacial interaction and the structural interaction were acceptable and concluded that they had an acceptable scoping and screening for license renewal. Part of the inspection we also look at the Aging Management Programs.

We review 22 and although we haven't gotten into the type of bigger issues in the Aging Management Programs, I will say we found notably fewer problems in that area. The lessons learned at Pilgrim and Vermont Yankee have been carried over and incorporated at FitzPatrick.

CHAIRMAN BONACA: I have a question regarding a comment made in the selective leaching program. The statement is made that soil chemistry in the area of the FitzPatrick power plant has not been determined by Entergy. This is the first time we haven't seen a table of the age, etc.

MEMBER WALLIS: There's no soil, it's all rock.

MR. MEYER: I think the write-up goes on to say that they had utilized the Nine Mile, the adjacent plant. They had done the analysis and carried that forward.

CHAIRMAN BONACA: So they used that.

MR. MEYER: Yes. They had specifics. It was basically the same area.

MR. BARTON: That was in the documentation some place, Mario. I think it's in our report.

CHAIRMAN BONACA: Okay.

MR. MEYER: Our review was similar to what we typically do in terms of reviewing the programs, talking with the people, seeing the evidence of the type of things that they are doing to be able to manage the effects of aging. There was one small issue on diesel-driven fire pump fuel line where our inspector was able to determine that the material was different than what had been in the application and they corrected that.

MR. BARTON: I've got a question. I don't know who should answer it but when you look at these different programs, in the structures monitoring program you made a statement, "It's an existing program that will be enhanced for an extended operating period. The enhancements will include additional items such as manholes, buck banks, frame rails, and girders."

Mike, what hit me there it seems to me you ought to be looking at that now. Especially under the maintenance rule or something you should be looking at some of these items. Are you guys looking at those things now or all of a sudden we are going to put it into a structural monitoring program for the next 20 years? I was confused.

MR. MEYER: I would say that the structural monitoring tended to come out of the maintenance rule so it's been in place for 10 years. What's in scope and what's not in scope is slightly different with the maintenance rule.

MR. YOUNG: This is Garry Young with Entergy. Some of these enhancements that are referred to are actually clarifications. The program currently does include a lot of the things that you had just listed there under the maintenance rule but they are not explicitly called out in the program document so we are adding that to the program document to make it very explicit.

MR. BARTON: Okay. Gotcha.

MR. MEDOFF: This is Jim Medoff. Let me just chime in for a second here. One of the things is just the fact that they don't credit a program for license renewal does not mean they are not implementing the program during the --

MR. BARTON: I was just confused. I understand. Thank you.

MR. MEYER: So in the Aging Management Program area we concluded that they had effective programs in place that would manage the aging effects. Our overall conclusion was that scoping, screening, and aging management programs are acceptable and we do not see any impediments to renewing the operating license. Any questions on the regional inspection?

MR. BARTON: That was a good inspection report.

MR. MEYER: Thank you.

MR. LE: Thank you, Glenn. Please stay here in case they have some questions you can answer.

I would like to comment about the interface within the region. I think we encouraged the reading and exchange experiences between region and people. Recently we invite all the regional experts who do the inspection for license renewal from

Region I, II, III, and IV in one room and day-long exchange of information.

Also the second purpose of that meeting of the experts, as we call it, is to come up with inspection procedures for the upcoming licensing commitment inspection before the applicant and during the period of extended operation.

As far as FitzPatrick, we did have the scoping and screening audit team came out first. What we found there we also send the information to Glenn and as well as anything that we learn from the audit team to Glenn to follow up with inspection on the region. We do propagate communication between headquarter. I don't know about other plants but at FitzPatrick I do that.

MR. MEYER: I should follow on in terms of the current performance. The next slide. FitzPatrick is in the licensee response column of the reactor oversight program which means that they have green performance indicators and green findings and they get the lowest level of inspection oversight.

There are no cross-cutting issues. In fact, when you look at the performance indicators all of the performance indicators are in the better half of the allowable band to be green. I think they have done pretty well.

Next slide. For findings the findings have been few and lower significance such that they were not cited. That concludes the current performance.

MR. BARTON: Thank you.

MEMBER ABDEL-KHALIK: As someone who has spent a lot of time at the plant and did a very thorough inspection, were you surprised by any of the questions that came up today with regard to the torus or the steam dryer. The torus I would have to say that is not my area of expertise and we do have an inspector who has consistently looked at that.

We at Pilgrim felt that they needed more reasonable assurance and that was kind of an arduous process to reach that point. FitzPatrick could benefit from it but the way the guidance is we didn't feel that there was a basis to insist on additional inspections.

It is a tough area with the coatings and the corrosion and how they review it and whether they use UT or not. I guess was I surprised by the questions? I wasn't surprised as an area of interest that merits review. I'm comfortable with the position that we're at with FitzPatrick.

MR. CONTE: I think it's an economic issue. You either want to keep monitoring or recoat. It's an economic question. We are focused on safety and they are focused on a lot of different things in addition to safety.

MR. BARTON: Recoating is expensive.

MR. CONTE: Pardon me?

MR. BARTON: Recoating is expensive.

MR. CONTE: Done that.

MEMBER WALLIS: It makes a better impression when you show a picture with no rust.

MR. LE: Do you have anything else to bring up? I think that's it.

On the next part of the presentation this is where the audit team is performing the duty. I expect the staff to jump in any time we have a question from a number of the subcommittee. On slide 20 we do an audit review of AMR and TLAA.

This portion of the audit is kind of changing from the past a little in that the audit team are now taking up some of the things that we send to the technical staff. Therefore, the audit team now we have engineering expert member and others in there with long time in industry.

Because of that the audit team would

review I would say from 90 to 95 percent of the applications. I think Ken Chan has head up a real good audit team and doing a better job of looking at all of the technical information in the application.

MR. CHAN: Ken Chan. Let me give a little introduction about what does the audit team review these days. We review AMPs, AMRs, and TLAA. FitzPatrick is the first plant that auditing take over the major responsibility of reviewing TLAA audit internal documents of applicants on site.

Before that it was performed by the technical divisions. It doesn't mean technical division is not consulted. We handle what we can for areas of emerging issues. Areas that doesn't have a set position we still request the technical division support us at work package.

AMPs emerging issues also we send down to tech division. AMRs most done by the audit team. When early on Tommy presented 83 percent it's a composite. It's really hard to say how much is totally consistent with GALL but the composite rate of review scope, audit scope done by audit team, TLAA, AMP, and TLAA together is normally over 90 percent. I am sure this is the case for Pilgrim.

What is presented to you is mostly the

safety reviews except a few instances. Some of them you already heard in the morning. Some of them we'll talk about this afternoon.

MR. LE: Thank you.

MR. MEDOFF: I just want to chime in on Ken's point. Some of the things that still go downstairs to the tech staff would be anything related to fracture tuffs on the vessel still goes down to the vessel crew. Nickel alloy cracking may still go down to the materials group so those are the type of issues that still go down to the tech staff.

The other thing I wanted to point out that Tommy did not say is even though we audit we still do a lot of consulting with the techs to make sure we are on the same page in our review. Let me emphasize that fact.

MR. LE: On the next slide, No. 21, this is summary of the audit. We have a total of 346 audit question. It's about half and half between the AMP and AMR as well as TLAA. TLAA is more or less in the second half portion of the question.

All of the 346 questions were responded to and resolved except two questions and one of those questions had to do with electrical where we have 115 underground cable that had no program to manage. We followed that with questions converted to RAI. The applicant finally came in with a program to manage that underground electrical cable.

The second audit question had to do with matter of fatigue and we turned in an RAI 4.3.3-1 and currently is still unresolved. It's a generic issue for all sights under review now.

MEMBER WALLIS: How do they do these questions? Apparently it's not just asking orally. You actually write down the question and it becomes a formal question?

MR. LE: The process, if I might go back, when we review the application to start with, we also consider that an acceptability. During that review we write all the questions that we have.

MEMBER WALLIS: Written down when you're here and then you go --

MR. LE: No. There are two stages. The first one we send 39I form before the audit to give the applicant a jump-start. When the staff get on site the applicant already knows some of the questions and the communication begins from day one. To continue on, the staff will ask a question by writing down verbally and then we ask the applicant to document the question for two purposes.

One is to show that they understand the staff question. No. 2, we want to establish a database. That goes on every day. The staff has to question and then we have what we call a meeting on each of the questions that I mentioned earlier with the plant engineer and the manager. We found a mutual agreeable solution whether it come with a commitment.

They explain to us in further detail that we satisfy the reviewer. This database is collected every day. Speaking of that, there is another process that we improve the documentation of data gathering. Out of that database the staff came back and produced for the first time at the FitzPatrick review what we call the audit summary report that had not been done before.

There are two purposes of that. One is to timely inform the public of what the audit team had found. Secondly it gave information for the technical staff to provide input to the SER. Before the audit report was bulky and mostly related you as part of SER. Now we have the data and we think about and we write the SER.

MEMBER WALLIS: Some of the questions seem to be a series of very similar questions. If we look at the DRL nozzle questions, it looks almost as if the same question is being asked over and over again until they get the right answer.

MR. LE: This is what I mentioned the first day. We asked the question but we didn't get the answer so we asked it in a different way.

MR. CHAN: Tommy described the detail very well so let me summarize in brief sentences. The question is the database. The question is the process. The first step we call big ticket RAIs. These RAIs are big items that we give them notice way ahead of time so they can prepare. That is part of the acceptance review that comes with 20 odd questions.

Then the real actual questions for the audit we promise to give applicants the questions that we intend to ask, the first round questions, two weeks ahead of audit so they have two weeks to prepare response so when we get there they can discuss with us right away so no waste of time.

That is the second level. When we get there we look at internal documents. We will come up with more questions so this is two-and-a-half level. The second one was heads-up questions. The third one is to make the heads-up questions complete. Then through the audit and break-up meetings we can generate new questions. Actually there are four levels of questions.

Now, FitzPatrick is the first plant we try as a pilot to see maybe we can generate a question and answer database complete enough to replace the audit report. We picked that as a trial case. That's why you can see there are many questions asked by different people.

The team leader do not have time to sort it through to compare one with another so repetitive questions like clarification-type of questions may exist there but if that pilot process is going to succeed, those will be fielded out. There's no sense to answer those questions. You sit down across the table and say, "Garry, is this correct?" That's it. You don't need to put on questions. This is a process of learning and trying.

MR. LE: Thank you, Dr. Ken. Slide 21 shows that out of this 346 questions 52 have resulted in the applicant to amend the application and there is a total of about 13 amendments through the application which is documented in the SER.

Compared to the other technical review we have a total of 118 RAI that I mentioned. Thirty-nine belong to the audit team. At this time the technical RAI is -- as compared to most of the others that we have reviewed.

As a result of Dr. Ken's audit there were 25 commitments finally docketed and some of these commitments are either enhanced, they are existing procedure or existing program. I believe 10 of them were new programs and that part of commitment as well.

On slide 22 this is another process that we improve ourselves. I mention before this is the first time that a private plant where we issue to the public the audit summary report. Next slides, 23 and 24, aging management review progress. The staff reviewed all 100 percent of the AMR document. One was reviewed by the technical staff with the Reactor Surveillance Program.

On slide 25 this is just a walk-through of all the systems that we have. Now I would like to present an example of the drywell aging management program that the applicant presented before. There are two areas that will control this. One is Containment and Service Inspection Program and the Containment Leak Rate Program.

Before we look at the document, operating experience and so on, there were no indication of leakage inside the drywell. The programs are consistent with our recent ISG interim step item that we issued last year when we had problems with Wolf Creek drywell.

The applicant does have a good monitoring program and they do that at every refueling outage. Like I mentioned to you, refuel and seal bellow, drywell air gap drain we look at with boroscope. Sand pocket drain we clearly look and they also functional check the alarm and the flow so that they can guarantee they have an operable system.

On slide 26 this has to do with the electrical at I&C. The staff review --

MEMBER WALLIS: Can I ask about those boroscope things? Boroscope is something you look through. You traverse it around and you look at things. Is there some record of what was seen or is it just in the eye of the beholder at the time or is there some record which an inspector can look at and say, "You see what we have seen by the boroscope?"

MR. PECHACEK: Joe Pechacek, Entergy Nuclear. Yes, we did tape it. It is available on tape.

COMMISSIONER WEAVER: So it's available to an inspector to look at it.

MR. PECHACEK: Videotape. Yes, sir. That is correct. There is also a written report describing the results that were seen on the tape.

MEMBER WALLIS: Did any of you look at the boroscope result?

MR. MEYER: Our inspector, who specializes in the torus and drywell, that was one of the things that he asked to see. I myself went in with Mr. Pechacek and the scaffolding was still thee from the boroscopic inspection so we went up and looked and I can attest to the fact that they were dry. And also that the torus room floor was dry. Yeah, the inspector looked at the videos.

MR. LE: Last week I went to the doctor and I had the same procedure.

MEMBER SHACK: Were you dry?

MR. LE: Well, the electrical and I&C the inspector -- the auditor came out with 20 come commitments. One is the bolted connection program that the staff came up with last year on E6. I think this program was not in the application and the staff request commitment about it.

Secondly, I mentioned before the 115 underground cable. The applicant did not have any program. We looked at the vendor manual and they do have some specific recommendations. We brought it up and we asked the applicant to implement it. The commitment 25, oil analysis and all that should be done.

CHAIRMAN BONACA: Let me say at this stage you were on schedule at the end of this portion. Then there is a TLAA presentation. Right?

MR. LE: Yes.

CHAIRMAN BONACA: And then discussion. Why don't we take a break now. We were scheduled to take a break at 3:00 so we'll take a break until 5 after 3:00 p.m. Then we'll conclude the review and discussion.

(Whereupon, at 2:46 p.m. off the record until 3:05 p.m.)

CHAIRMAN BONACA: Okay. Let's get back into session. We have now the remaining presentation on time-limited aging analyses. Then we will have the subcommittee discussions at the end of the meeting. We are going to you, Tommy. Right?

MR. LE: Yes. Thank you. Thank you, Dr. Bonaca. To continue with the staff presentation and the result of the staff review of the FitzPatrick license renewal application, my name is Tommy Le. I'm the project manager for this review.

Now is the time on slide 27 the staff had reviewed and the applicant include all the TLAA shown in the license renewal and state that FitzPatrick had no exemptions as required by you to report to the staff during this review.

In the next slide we would like to talk about the two open items that have previously been mentioned. All of these are in TLAA area. Speaking of this, I understand the subcommittee also had a question on weld overlay and internal. Jim, I will move him up here so he can hear the question and respond to you properly.

MR. MEDOFF: I will address them in the question and answer period for you.

MR. LE: On slide No. 29 the staff have reported to the subcommittee that we have an open item for TLAA 4.2.1 that had to do with the reactor vessel neutron calculation. Ambrose Lois was the staff expert. I don't know where we are going to get another one.

With that, the applicant has stated that another calculation has been performed and they are doing a QA review to make sure that reg guide 1.190 is followed. I understand they will submit the application to us in September, which is this month. From what rumor I heard, the number they came up with is very conservative. Lower than the number they submit in the application.

DR. KUO: Excuse me. You are talking about amendment. Right? Not application.

MR. LE: Yes.

MEMBER MAYNARD: I just want to make sure on the neutron issue, the reason it was not in accordance with reg guide 1.19 is because the flex that was certainly reported in the 25 to 30 were outside the recommended range?

MR. LE: Dr. Lois, Ambrose, will address this question.

MR. LOIS: I just want to make sure I understand why it didn't meet the -- this is Ambrose Lois, Reactor Systems. Those calculations of record were performed by GE way before GE had an approved methodology. After we reviewed their methods and we approved it in 2001 we made a number of changes to the process that they were following.

We issued the regulatory guide in 2001 again, 1.190, which describes an acceptable methodology which complies with what we require to have. That's where the difference is. It has to go back and recalculate it to make sure it complies with those requirements. Something else I may point out is that volumes that were calculated of fluence by GE before 2001 tend to be conservative, sometimes overly conservative.

MEMBER MAYNARD: Okay, but have they formed a calculation for the extended period to go to the 54 effective full power years?

MR. LOIS: Yes.

MEMBER MAYNARD: After 2001? That's been recently. Right?

MR. LOIS: Yes.

MEMBER MAYNARD: So they used the old methodology then? It has not been updated to the current reg guide?

MR. LOIS: The one that's of record now for 32 effective full power years is with the new operating authority. I guess what we have for the 50 -- what we expect to receive this month is the updated methodology for the extended period.

MEMBER MAYNARD: Okay. So they have not submitted that as part of their application?

MR. LOIS: Not yet.

MR. MEDOFF: Let me just clarify. They have values in the application. The open item is to do a new assessment for them and then to confirm that the fluence used in the application for neutron are conservative meaning that the value is bounded by the value reported in the application.

MEMBER ABDEL-KHALIK: How were the values included in the original application and the associated uncertainties determined? I guess I'm just following -- I have the same difficulty as Otto understanding the chronology of this process.

MR. COX: This is Alan Cox with Entergy, License Renewal Team. The values that are in the application were based on GE's analysis that was done in accordance with the draft reg guide that preceded reg guide 1.190. What we did is we took the 32 EFPY values and did the straight line extrapolation based on the uprated power levels for the 54 EFPY numbers that are in the application.

MEMBER MAYNARD: Okay. So you did not run a new calculation. You basically extrapolated from the existing calculation.

MR. COX: That's correct.

MEMBER MAYNARD: Okay.

MEMBER SHACK: What are you doing now?

MR. COX: Now they are doing a new calculation with the RAMA technology. George can probably talk a little bit more about that.

MR. LOIS: They are changing the methodology they have.

MEMBER ABDEL-KHALIK: But do you get the same answer? That was my original question. Are the fluences going to be much larger with the new methodology?

MR. MEDOFF: The short answer is you get the same answer.

MEMBER WALLIS: You get the same answer.

MR. MEDOFF: Yes.

MEMBER WALLIS: Will these be available before the full committee meeting?

MR. MEDOFF: I'm not sure about that.

MEMBER WALLIS: Where will this put the CRS if we are asked to approve something? A whole lot of things depend upon this.

MEMBER MAYNARD: I think that they have provided a lot of good information to show that we are talking about how we meet the legal requirements for the calculation of record. I was just trying to understand why -- I thought there had been a new calculation done for the extended period of operation but now I understand they had basically extrapolated from an older one that was done under the draft reg guide as opposed to the current reg guide. Now I understand why there is a legal issue.

MR. LOIS: Also there is another issue

that they have changed methodology. They have opted to use the so-called RAMA code which is an entirely different basis and having some problems of its own. As to the question before us whether they get the same answer, our definition of the same answer is whether the two methodologies are within each other's uncertainties. Of course, that could be in the neighborhood of about 10 or 15 percent with current methodologies.

MEMBER MAYNARD: It's not an order of magnitude?

MR. LOIS: Hopefully not.

MR. MEDOFF: And the thing is Lois Ambrose will get the new calculations, or someone in reactor systems. They will review it to confirm that the methodology conforms to the reg guide. If the values are less conservative, then they have to redo all those TLAAs because the values they provide in the application won't be acceptable anymore. That is basically how it's going to work.

MEMBER SHACK: Which is why all those sub-items are open.

DR. KUO: And we would like to have the information or resolve the issue before the full committee meeting.

CHAIRMAN BONACA: We want to close these items.

MR. MEDOFF: We do have two members from Division of Component Integrity that do review those type of calculations and they are working closely with Ambrose to make sure the open items get closed.

MR. LE: I will interface with the applicant and get the report in. Staff will review and confirm all the values that we based on doing the review of all the TLAA bounded by the new map.

Okay. We have open item on neutron fluence. The next slide, No. 30. Because the number was not accepted by the staff, the staff had reviewed the other TLAA based on the conservative number that the applicant had projected. What we got depending on the fluence calculations these six items and one AMP will be closed after the fluence calculation and value having resolved.

In the next slide, No. 31, Section 4.3 under metal fatigue. Dr. P. T. Kuo had addressed the environmentally-adjusted issue this morning with the subcommittee. During the audit review the staff interfaced with the applicant technical person and the same audit team had been at other plants like Pilgrim.

The same issue came up at FitzPatrick so the applicant have provide us with commitment No. 20 in which it gave us several options that it would take if the CUF ever approach 1. I believe several positions in the reactor internal approaching 1 or about 1 for the projected standard operation.

So commitment 20 was delivered and committed. When the staff came back on June 20th the applicant sent in another amendment saying that they will modify the commitment a little and will in effect monitor and refine and maintain the CUF under a value of 1.

The staff was not very at ease with this new amendment so we send an RAI out on July 25th. It was the Friday before we issued the SER with open item and request them to provide more detail. The rest of it you heard today from everybody.

MEMBER WALLIS: They are going to replace the RPV shelf?

MR. LE: Yes, repair or replace.

MEMBER ARMIJO: One of these things is a recirc inlet nozzle thermal sleeve that has a cumulative usage factor of 4.93.

MR. MEDOFF: That's the reason for the commitment. They had already done -- I understand there are six locations in NUREG CR6260.

MEMBER ARMIJO: If that number is right, they are already beyond 1 without being --

MR. MEDOFF: Just remember the current licensing basis does not include the FEN adjustments of the CUF. This is only for license renewal that the industry has agreed to do these additional assessments. The question is if you had done the FEN adjustments of these critical locations in the NUREG, what are you going to do if your adjusted CUF is over 1 and they gave us this commitment to tell us how -- some of the options they deal with for corrected action.

MEMBER ARMIJO: What is the likelihood that this thing can be resolved with anything other than just replacement? Something with that much of a discrepancy between --

MR. MEDOFF: They don't necessarily have to replace. One of the options is for them to propose an inspection-based monitoring program or to use an aging management program to manage the aging effect.

CHAIRMAN BONACA: Isn't it the same thing as the third bullet?

MR. MEDOFF: No, there's a difference. The third bullet is -- remember there's three criteria for TLAAs. Single I means analysis remains bounding.

II means that we have done the calculations, projected them out, and they are still valid. They meet the acceptance criteria. The third one is if you can't meet I or II, then you propose III and you have managed the aging effect, one of the intended functions of the component.

CHAIRMAN BONACA: Which means you monitor it and you repair it.

MR. MEDOFF: In this case they will submit a response. We expect it will be similar to that for Pilgrim. If the response is the same, the anticipation is that they would envelope those options into their fatigue monitoring program.

CHAIRMAN BONACA: What I meant was the managing to me means that you will inspect and repair and replace if you have to.

MR. MEDOFF: This is not only a technical issue but we also got some legal comments from OGC and the question is they felt that enveloping this commitment under III would sort of use III to involve II. There is a question of how you -- there is a legal question here and so what you're doing is they are enveloping the commitment into their fatigue monitoring program.

MR. CHAN: Excuse me. Ken Chan. Let me

put some focus on it. Let's pick the reactor in the nozzle circulation. That is already 4. something. That already exceed the code limits. Right away you need to manage the nozzle. One day after the 40 years you have to do that. In the meantime the applicant have the choice of refining their calculation to get the 4. something down to 3. something, 2. something, or 1. something.

What does 1. something do you? It's still not acceptable but it gives you an indication at the 40 years you may have exceeded 1.0. At 38 years it may be less than 1. It gives you a warning signal when you have to pay attention to develop your aging management program to assure in future operations step by step you will not exceed 1. That's the whole purpose.

MEMBER ABDEL-KHALIK: Isn't that 4.93 value evaluated in accordance with the code?

MR. CHAN: That's based on a very conservative way of the code. It uses the design cycle, not the projected cycle. It uses a design transient, not the extra transient. I am not that familiar with BWRs but for PWRs if you have implemented a modified operating procedure the specification transient goes way down dramatically.

In the meantime I would do everything I can to put a realistic projection of cycle and training in there so it will not be 4. something. Also, FEN. Everybody is familiar with FEN. The realistic number is maybe 4 or 5. Right now it's 15 so you get so high. When you get it on 8 it's reduced by factor 2. When you get down to 4 another factor of 2. There are plenty of ways to have a sophisticated --

MEMBER ABDEL-KHALIK: You think with a more realistic including some uncertainties but more realistic analysis this particular component could possibly be acceptable?

MR. CHAN: May I give you a judgmental statement?

MEMBER ABDEL-KHALIK: Yes.

MR. CHAN: My feeling is yes. I have a whole PWR with maybe only one component and out of BWR I think everyone could pass if you do a bang-up job. The applicant may disagree with me but I'm speaking for --

MR. YOUNG: This is Garry Young with Entergy. I agree with what Ken was saying. That is really the plan right now. We are making this part of the fatigue monitoring program. Prior to that point where we might see 1 we will either reanalyze with a more detailed calculation. If that's not successful, then we'll do a repair replacement and the rest of the options. We expect the analysis to be successful.

MR. MEDOFF: One of the things they pointed out to us in our discussions with them is putting this commitment under the fatigue and monitoring making the program consistent with GALL without exception. That's an important point because that means they can use fatigue monitoring program to accept the TLAA under III.

MR. LE: To continue on, in summary we have two open items that we have discussed. On slide 33 on the equipment qualification of electrical equipment the staff reviewed the TLAA on this and had concluded that all the applicant evaluation in the application was acceptable.

Speaking of electrical, I might like to backtrack a little. During the review of the 115 underground cable where we had noted from day one when we reviewed the application, we had discussed this with the applicant many times and after the audit we had many conference calls and so on saying, "You still don't have an AMP program to manage the underground cable."

I don't want to leave the impression that we made the applicant to do the AMP but we expressed our concern very consistently through many phone calls and they finally proposed an AMP program.

With that, the staff now concluded that on the basis of the staff review, the audit team, the regional inspection team, with the two exceptions the staff now determined that the requirement of the 54.29(a) had been met and, therefore, with the resolving of the two open items we think the application is acceptable.

With that, any questions?

CHAIRMAN BONACA: Any questions from the members?

MR. BARTON: I had a question but I think it's for the licensee. I forgot to ask earlier.

CHAIRMAN BONACA: You can ask now.

MR. BARTON: There's an AMP B1-15 heat exchange and monitoring program. You have a new plant specific heat exchange and monitoring program that will inspect heat exchangers for degradation. Visual inspection and any current testing will be performed. The heat exchangers that you are adding in this program are HPCI turbine lube oil, land sill condenser, and emergency diesel lube oil heat exchanger.

Why only are those heat exchangers being added in this program? I know you are doing turbine building closed cooling water reactor building and closed cooling water in the chemistry program and now you're going to have inspection program for additional heat exchangers. Why is it just limited to those few heat exchangers? I'm missing something.

MR. LEITER: This is Larry Leiter, system engineering from FitzPatrick. Those are the inscope heat exchangers that are cooled by fluids other than service water or lake water. Lake water cool heat exchangers are included in the 8913 program under service water monitoring and these are separate.

MR. BARTON: All right. I understand. Thank you.

CHAIRMAN BONACA: Other questions?

MR. MEDOFF: If you would like me to address your questions I can give you some clarification on TOP guides, core plate bolts, jet pump assemblies. I was the reviewers. This is Jim Medoff with the Division of License Renewal, Branch C. I was part of the audit team and one of the senior staff members on the team. I was responsible for the vessels internals and overseeing our contract review and some of the other BWR inspection programs that were based on VIP guidelines.

You have to understand one thing is that the VIP program for boiling water reactors the only thing that is a requirement in these programs would be the Section 11 inspections that those VIP guidelines might invoke.

Any inspections beyond those go beyond our requirements. This is a program that was implemented on behalf of the senior vice presidents or presidents of the utilities all agree that they would implement a VIP program to monitor aging in their internal components and some of the penetrations to the vessel.

This came out of the fall. I have some of the course cracking that was discovered at the Brunswick facility in 1993. This utility energy has a fully developed VIP program for their penetrations, their vessel components, and their internals.

They have a corporate document that commits them to implement a VIP 94 which are the implementations for implementing all the NRC approved VIP documents which are the flaw evaluations and inspection guidelines for the various components.

For their TOP guide they are following VIP 26 as modified by the GALL. One of the things that came out in the GALL report is that the VIP document does not recommend any inspections for the TOP guide grid beam locations. We felt that for license renewal there were some plants that had some cracking in those locations so we felt it was important to manage aging in the grid beam.

In the GALL report we put a recommendation to do additional inspections of the grid beam locations. It should be 5 percent of the grid beam locations within six years of entering the period of extended operation and another 5 percent within the next five years.

There has been some cracking at some plants so Entergy is willing to commit to an additional 5 percent in years 12 through 18 to cover the last third of the period of extended operations to ensure that they will manage any potential cracking in the grid beam locations. They have a commitment on that.

For the dryers we are aware that ACRS has written a letter to the commission that steam dryers should be in scope and they should have aging management programs for them. We have a commitment from the utility to implement VIP 139 in the NRC approved form. That is currently under review by the

Division of Engineering but I am in constant contact with the Tech Division to find out where we stand on all guidelines under staff review.

I think one of the components is why did they defer the inspections of the accessible jet pump assembly components and that was one of my questions. They indicated to me that their deferral was only for one refueling outage and they did get all the recommended locations, accessible locations, for their jet pump assemblies so we felt that was adequate to cover the recommendations for the jet pumps.

I think the final component that you wanted me to cover was the core plate rim hold-down bolts. For FitzPatrick they were in a special situation because they concluded due to their configuration they couldn't perform the recommended VIP inspections for those bolts.

They submitted a relief request that for those core plate rim hold-down bolts that the Section 11 inspections would be sufficient and the relief request got approved but we can't use relief request for aging management because they are not approved for the period of extended operation. Another thing is the Section 11 exams only proposed VT-3 visual examinations of these locations which may not be adequate.

The applicant committed to either install wedges which would replace the bolts of the structural member for the core plate against lateral movement or to submit an analysis and inspection plan for review and approval to manage stress relaxation of the bolts and we felt that was adequate.

MR. BARTON: So what's different here? Every boiler's got the same issue. You can't inspect so is everybody just putting wedges in? What's different with this plant with respect to that?

MR. MEDOFF: It depends on your vintage and your design. Some plants the core plates have a general assessment. The core plates have a general assessment in that they assess the core plates and the designs for the various plants that are in the fleet. For this plant it's just that their configuration wasn't accessible.

MR. CHAN: This plant compared to the same vintage BWR plants there's no difference. The option is there always. If you want to install the wedge now, fine. If you would rather take a risk to wait for a little while, maybe the technique develops and you may save it. At the time you are implementing maybe you ought to rush the schedule.

There are plants that say, "We installed a wedge." That's it. Some plants will say, "We continue to inspect performance and at the proper time the technique may be there. If the technique is not developed, then we install the wedge." The solution is the same.

MR. MEDOFF: So the solution for them is to do an analysis and propose an inspection plan for all review and approval which means Barry Elliot's group Division of Component and Integrity will get a chance to look at that inspection plan to see if it's adequate for aging management.

CHAIRMAN BONACA: I have no problem at all with the response from the licensee. My only question was what about core and licensing barrier. That's all.

MR. MEDOFF: Since the VIP program is an existing program, the Division of Component and Integrity does have a project manager for all VIP documents and they do review these documents for acceptability. There are constant dialogues with the VIP communities to assess what is needed for the internal.

These programs for the boiling water reactors are not only assessed for license renewal during our application reviews but the tech staff do full reviews of these documents to make sure that the internals will get adequately managed.

CHAIRMAN BONACA: Okay. I thank you. Are there anymore questions? If not, I would like to thank all the presenters. That was a very good presentation. I think what I would like to do now is to go around the table and give views of individual members on what took place and what we heard and then we'll close the meeting.

MR. LE: Thank you, Dr. Bonaca.

CHAIRMAN BONACA: Thank you. Why don't we start with John.

MR. BARTON: Just a couple things. Of course, we got the open items yet to get resolved satisfactorily. I looked hard at the commitments and they consist primarily of implementing aging management programs or enhancing aging management programs. Based on what I looked at I find there are really no issues in the commitment list that concern me for extended operation.

I really didn't see anything in this application for a BWR basically that I haven't seen before. I think from the discussions I heard today on proposed resolutions for those items if they are satisfactory and the NRC accepts the resolutions, I don't have any other issues with this station.

CHAIRMAN BONACA: Thank you.

MEMBER MAYNARD: Overall I don't see any major issues. I think it would be nice if the applicant would look inside the torus if they ever have a drain for any reason. I wouldn't say they would have to drain it.

I think it would be nice to see some UT sampling or something in some other locations but, again, I look at this as something I think would be a nice thing to do. I don't see a real regulatory basis for it and I believe that what they are doing beats the requirements and should be all right. I do think a couple of things need to be considered by the licensee or the applicant.

I would like -- my other comments are more generic in nature. We talked about an aging management programs either exceptions or with enhancements. I would kind of like to see those two divided out. An aging management program with enhancements to meet GALL, okay, I kind of put that into the category of meets GALL.

It's the number with exceptions that to me is a little bit more meaningful. I'm not sure when you include those all in one grouping with exceptions or enhancements just may get a better perspective on how many real exceptions there are.

The other thing is I am glad to see that the headquarters and regional staff are doing some information sharing and some lessons learned stuff from this. It also sounds like there is going to be some sharing between regions and I do think that's going to help with consistency across the board.

I think scoping is going to continue to be an issue and we either need to recognize that it's going to be there and not beat up the licensee so much or else we are going to have to provide some better guidance not only to the licensee but to the inspectors and stuff to allow more consistency or else I think there is always going to be some scoping issues identified as part of it. Might even consider a workshop or something. We've been doing this for a while.

I think there have been a lot of lessons learned and maybe it's time for a workshop or something to kind of share between the industry and the NRC and have some exchange there. Other than that I thought the applicant was prepared and did a good job of presenting. I think the staff had answers to the questions.

CHAIRMAN BONACA: Thank you. Said.

MEMBER ABDEL-KHALIK: I agree with the comments that Otto has made but I'm a little bit more concerned about the condition of the torus. I do not believe that any analysis was presented that would show me convincingly that the torus will remain sort of within tech spec limits as far as the minimum thickness is concerned throughout the period of extended operation.

Or that the areas that they are currently sampling are totally representative of the conditions within the torus because I haven't seen any information as to how those bad locations were selected in the first place and whether or not they are actually representative of the entire surface.

Therefore I would agree but I would like to see sort of an assessment of how those points were selected in the first place and a convincing argument that they really represent the worst conditions. If that is the case, then we would have some confidence that the remaining areas in the torus will be limited by whatever data they are currently collecting. Absent that, I'm not sure that the answer is there.

CHAIRMAN BONACA: I wonder if that would

not be a good initiative for the BWR VIP to look at. I mean, look at generically for all the boilers. This is not specific to FitzPatrick. I mean, FitzPatrick really looks like -- I mean, they had a leakage that wasn't tied to a pitting. It was tied to a stress condition so that's -- some initiative on the part of the VIP would be beneficial.

MEMBER MAYNARD: That could certainly be a topic we would want discussed at the full committee meeting may be better justification as to why --

MEMBER ABDEL-KHALIK: Right. I mean --

CHAIRMAN BONACA: When we go to the full committee meeting just --

MEMBER MAYNARD: The data may be there so that as to how these points were selected in the first place and whether they really represent the worst locations so that one would have some confidence that the small number of locations that they are continuously monitoring is truly representative of what the condition is going to be and the extrapolation that they are making as far as the thinning of those areas would be applicable to the entire torus.

MEMBER MAYNARD: I think they said they identified them by when it was drained once they went in and looked and that is how they identified them. It would probably be good to hear that again.

MEMBER ARMIJO: How confident that the UT measurements that they will be taking periodically how reliable those things are so you can have some confidence in their extrapolated damage.

CHAIRMAN BONACA: Thank you, Said.

MEMBER ARMIJO: I agree more with Said's point. I was surprised there wasn't any kind of mitigation even locally to recoat those local areas that had the pitting and still do the UT measurements to make sure that it had absolutely stopped it.

That wasn't done so I think I would like to see more discussion in the full committee meeting of why their approach is basically acceptable. I would like to see at least some spot checks even if only one time somewhere else at random.

MEMBER SHACK: Of course, if you're looking for pitting on a porous --

MEMBER ARMIJO: You're right. It's pretty random.

MEMBER SHACK: -- it's pretty random.

MEMBER ARMIJO: Pretty low probability. You're right. I don't know. It just seemed to me that coating broke down somewhere for some reason and caused a pit. They didn't grow by themselves.

With time is that coating going to get any better? I doubt it. I think it's going to get worse so you're probably going to see some more of that stuff but I think it's really an economic issue. The utility can decide what is more expensive.

MEMBER MAYNARD: I was kind of surprised that they didn't recoat or do something. However, by not doing it it really does provide a better leading edge indicator of what's going on.

MEMBER ARMIJO: You could argue that. Otherwise, the rest of it was all very good. All the issues on fluence I think are being handled well. The same with the fatigue. I think those things will get resolved. I don't have any real problems.

CHAIRMAN BONACA: Okay. Thank you. Graham.

MEMBER WALLIS: I have little to add. I agree with my colleagues. I don't think there are problems as long as these issues can be resolved. They seem to be on track to be resolved. I would like to say I thought the audit was a very useful, very thorough audit performed by the staff. Generally the staff and the applicant did a good job. I think we'll be okay.

CHAIRMAN BONACA: Bill.

MEMBER SHACK: I agree with most of what my colleagues have said. I'm certainly more comfortable than Said is with the torus inspection program. I really as a practical matter don't see what you could really do except to have them drain it periodically. I just don't see any particular -- to me the

chances -- you know, you're going from inception to 1998.

You have probably found the weak spots in the coating. Those are leading indicators. You are monitoring those closely. As I say, random sampling just seems to me impractical when the problem is pitting and the expense of the alternative just doesn't seem to be justifiable.

MR. BARTON: One thing that you could do is periodically have a diver go underwater and look rather than draining it and doing an inspection. We used to do that and we did find some indications.

CHAIRMAN BONACA: How detectable is the leakage?

MR. BARTON: All we looked for was flaws in the coating. That's what you look for. You look for indications that you see flaws in the coating and then zero in on those areas. That's about all we can do.

MEMBER MAYNARD: I do think we need to be careful. That is a major undertaking. I mean, the more you do those are the areas that you are not really wanting to put people into unnecessarily but it is a way, though. I agree that would be an alternative but it should not be taken lightly.

MR. BARTON: No, that's right.

CHAIRMAN BONACA: I share all the views in the presentations. I think they were very good. I was very impressed with the work they did and I was very impressed with the work that the staff has done. I want to recognize here the regional inspections that brought out the issues at Vermont Yankee.

I think these kind of findings typically then communicates to the rest of the industry and people learn from this experience and that's very important that the experience made at the plant is brought to other plants and you guys are doing that. That's good. That gives me the comfort that within the limit of what is possible the component is being identified correctly.

On the torus, really I view it as more of a generic issue than a specific one to FitzPatrick, as

I said before, because the leak that they had wasn't a pitting problem. More could be done and certainly would be desirable to see better initiative maybe on the part of the VIP. There could be some brainstorming about is it needed. The point that Bill made is well taken, too. There are leading indicators which have been monitored and where do you stop.

In general I think the application was good. I think I don't see the open items as being any measurable obstacle to the closure of them. I think the licensee has done a good job in their presentation. My suggestion is that when we go to the full committee meeting the licensee takes the issue of the torus.

Give us as much information as you can about what you're looking at and what gives you the comfort that you can manage it with what you've got now for the foreseeable future. You know what the questioning has been here and you can expect the same questioning from the other members.

MEMBER ARMIJO: If the licensee has photographs, that has been very helpful in previous discussions on torus problems.

MEMBER WALLIS: Not just pictures but data.

MEMBER ARMIJO: Yes, what do they look like. The trouble with pits on something as big as a torus they are hard to find. What's a guarantee that the initial locations that have pitting were the only locations.

MEMBER WALLIS: I thought the ones that were found --

MEMBER ARMIJO: There could be worse spots somewhere else.

CHAIRMAN BONACA: Okay. Well, with that, I would like to ask the question is there any other questions from the members or the public or the staff? No questions and no further comments. With that then I will adjourn the meeting. Thank you very much.

(Whereupon, at 3:51 p.m. the meeting was adjourned.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards

Docket Number: n/a

Location: Rockville, MD

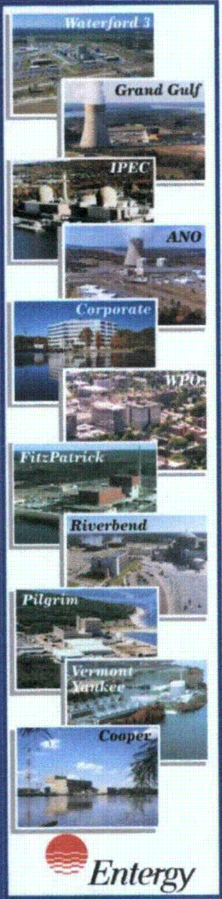
were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

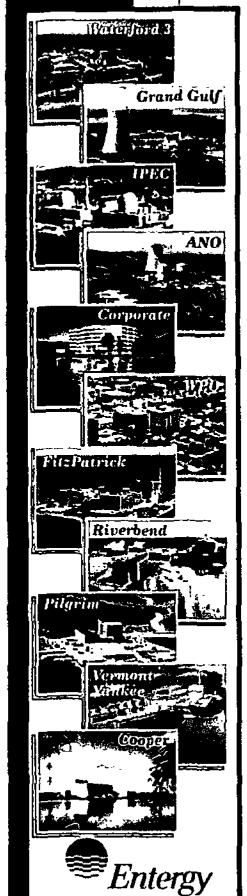
Charles Morrison

Charles Morrison
Official Reporter
Neal R. Gross & Co., Inc.

James A. FitzPatrick Nuclear Power Plant

ACRS License Renewal Subcommittee Presentation
September 5, 2007

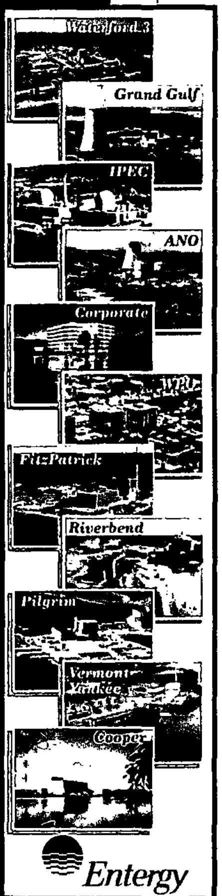




James A. FitzPatrick Personnel in Attendance

Brian Finn	Site NSA Director
John McCann	Director of Licensing, White Plains
Garry Young	Manager, License Renewal
Steve Bono	Director of Engineering
Joe Pechacek	Manager, Programs & Components
James Costedio	Licensing Manager
Alan Cox	Technical Manager
Rick Plasse	Licensing Lead
Larry Leiter	Technical Lead
Tom Moskalyk	Structural Lead
Arturo Smith	Class 1 Mechanical Lead

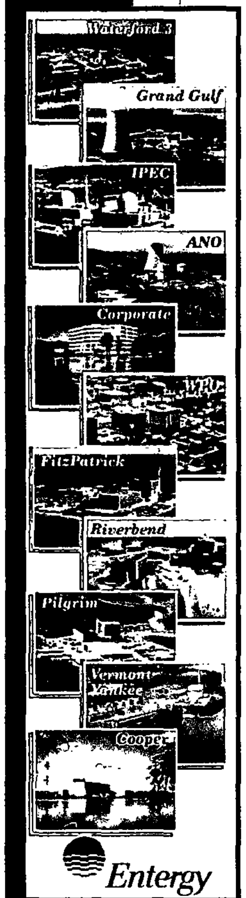
Technical Support Personnel



Agenda

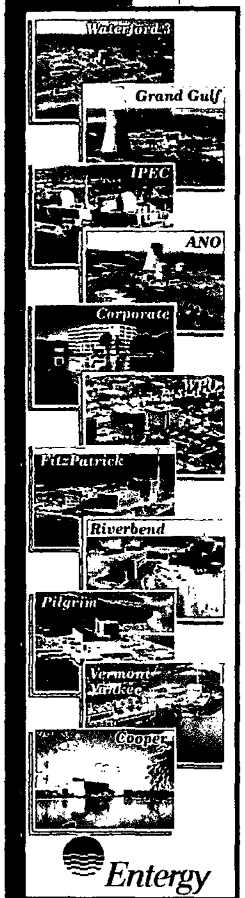
- James A. FitzPatrick Site Description
- Current Status
- James A. FitzPatrick Licensing History & Highlights
- License Renewal Project
- Cost-Beneficial SAMAs
- Presentation Topics
  - Drywell and Torus Monitoring
  - Torus Repair
- Questions

JAFNPP Site Description



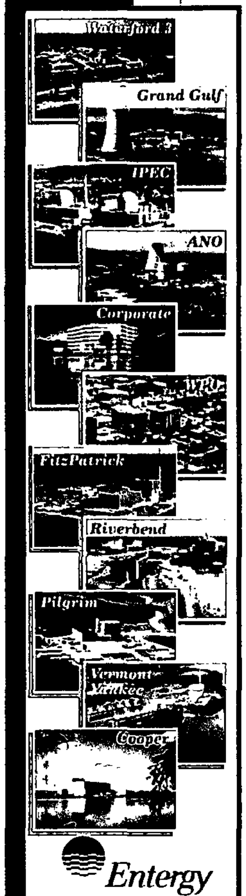
- General Electric (NSSS & TG), Stone & Webster (AE and Constructor)
- BWR-4, Mark I Containment
- 2536 MWt Thermal Power; ~ 881 MWe
- Once through cooling from Lake Ontario
- Staff Complement: approximately 650

JAFNPP Plant Status



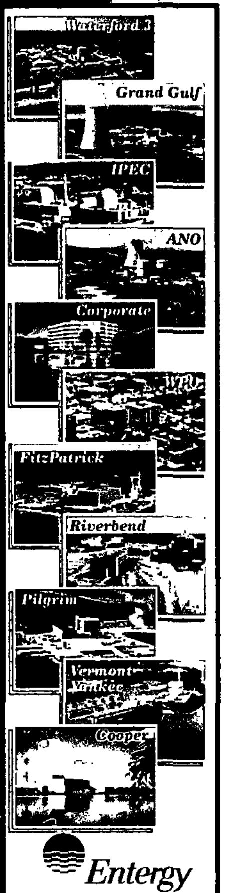
- Startup from RFO 17 - November 4, 2006
- Current Plant Status
- Next outage Sept 2008

Licensing History



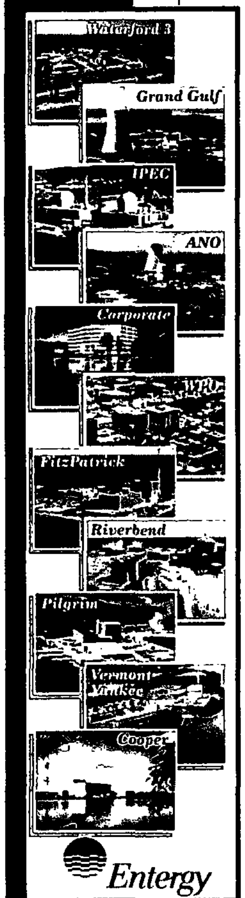
Construction Permit	May 20, 1970
Operating License	October 17, 1974
Commercial Operation	July 28, 1975
Uprated Power License (4%)	December 6, 1996
License Transfer to Entergy	November 21, 2000
LR Application Submitted	July 31, 2006
Operating License Expires	October 17, 2014

Major Improvements



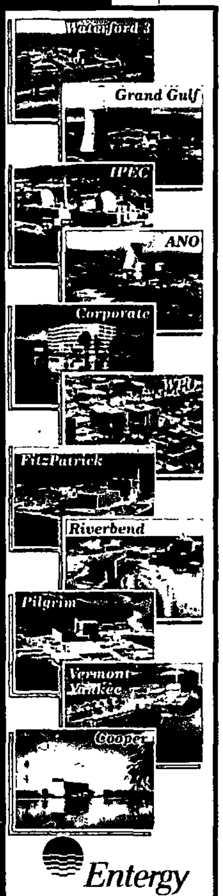
1978-1983	Mark I Containment Modifications
1988	Hydrogen Water Chemistry
1989	Zinc Injection
1990	Power Uprate Equipment Upgrades
1998	ECCS Suction Strainers Replaced
1999	Noble Metals Application
2004	LP Turbine Rotor Replacement
2004	Noble Metals Application 2
2006	HP Turbine Rotor Replacement
2006	Offgas Condenser Replacement
2006	HPCI Discharge Exhaust Sparger Added

Future Improvements



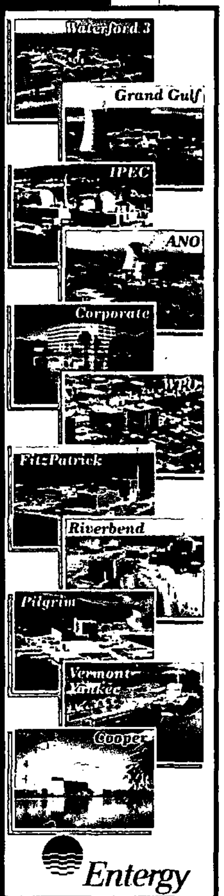
2008	Main Transformer Replacement
2008	Core Spray Motor Replacement
2008	345KV Breaker Replacement

JAFNPP License Renewal Project



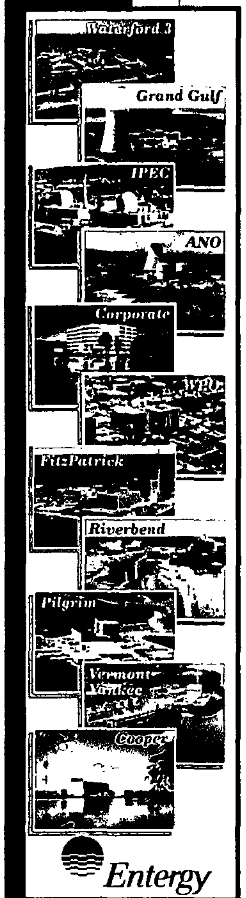
- LRA Prepared by experienced, multi-discipline Entergy team (utilized corporate and on-site resources)
- Incorporated lessons learned from previous applications
- Peer review conducted
- LRA internal reviews (Safety Review Committees and QA)
- All comments resolved prior to submittal

JAFNPP License Renewal Project



- License Renewal Commitments
  - Refined during audit/inspection process
  - Tracked by Entergy commitment tracking and engineering work tracking systems
- 36 Aging Management Programs
  - 17 Programs in Place w/o Enhancements
  - 9 Programs will be Enhanced
  - 10 New Programs
- GALL Consistancy
  - 10 Consistent
  - 20 Consistent with exceptions / enhancements
  - 6 Plant Specific

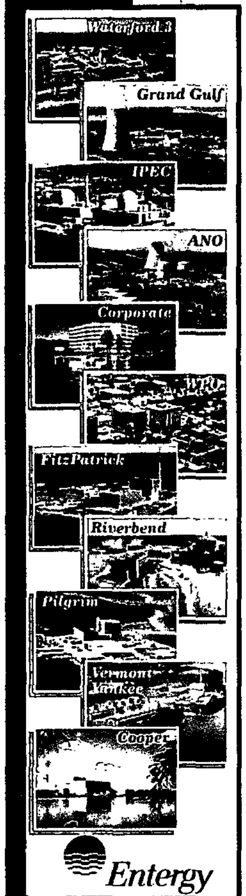
JAFNPP License Renewal Project



Program Implementation Plan

- Develop fleet approach for Entergy plants that have submitted an LRA
- Develop schedule using industry experience

JAFNPP License Renewal Project

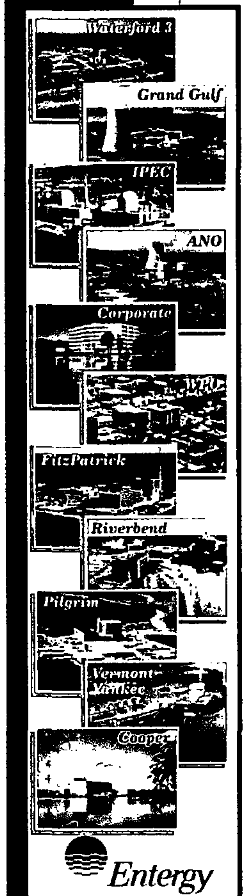


Scoping of Non safety-Related Systems, Structures, and Components

(10 CFR 54.4a(2))

- Utilized site component database, P&IDs, and isometric drawings
- Reviewed safety related cable / piping locations
- Performed walkdowns for a(2) scope verification

JAFNPP License Renewal Project

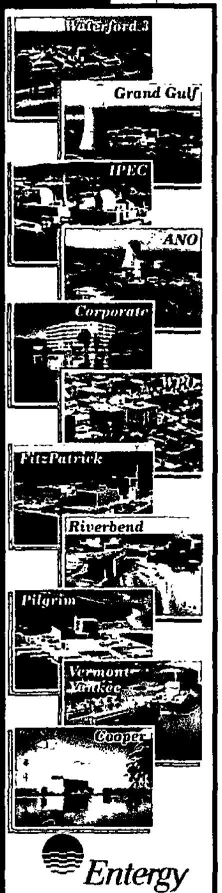


Scoping of Non safety-Related Systems, Structures, and Components

(10 CFR 54.4a(2))

- Regional Inspection verified a(2) scoping for in-plant areas and systems
- 10 CFR 54.4a(2) scope changes made in LRA Amendment 11
- Regional Inspection concluded that JAF had implemented an acceptable method of scoping and screening of non-safety related SSCs and that this method resulted in accurate scoping determinations

JAFNPP License Renewal Project

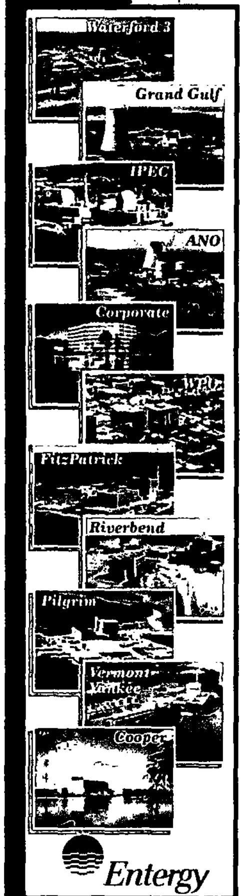


Draft SER Summary

- Open Items – 2
  - Reactor Vessel Fluence
  - Environmentally Assisted Fatigue

- Confirmatory Items – None

JAFNPP License Renewal Project

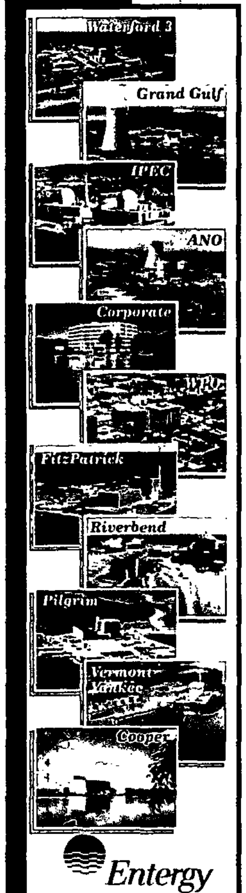


Reactor Vessel Neutron Fluence

- **Current P-T curves valid through 2014 (32EFPY)**
- **Submit RG 1.190 calculations by September 2007**
- Evaluated TLAAs to determine limiting fluence (RG 1.99)
  - Adjusted Reference Temperatures (<200F)
  - Upper Shelf Energy (>50 ft-lb)
  - RPV welds
  - RPV nozzles near beltline

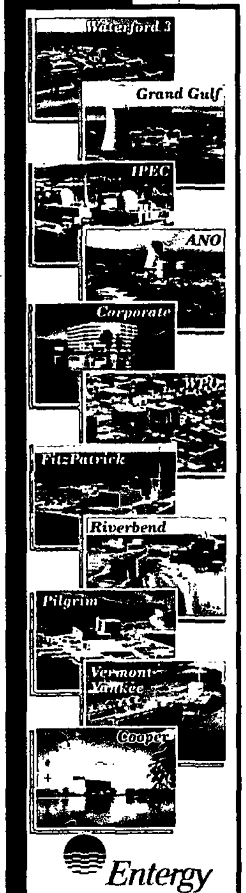
- Axial Weld Failure Probability is limiting at $5x10^{-6}$ per Reactor Year
- ART and USE values will not be challenged at 54 EFPY

JAFNPP License Renewal Project



Environmentally Assisted Fatigue

- JAF will demonstrate that cumulative usage factors (CUF) of the most fatigue sensitive locations are less than 1.0 throughout the license renewal period by first using Option (1) of commitment #20
- Analysis methods for determination of stresses and fatigue usage will be in accordance with NRC endorsed ASME Boiler and Pressure Vessel Code
- JAF will utilize design transient specifications and information from BWR-4 references to bound operational transients



JAFNPP License Renewal Project

Environmentally Assisted Fatigue

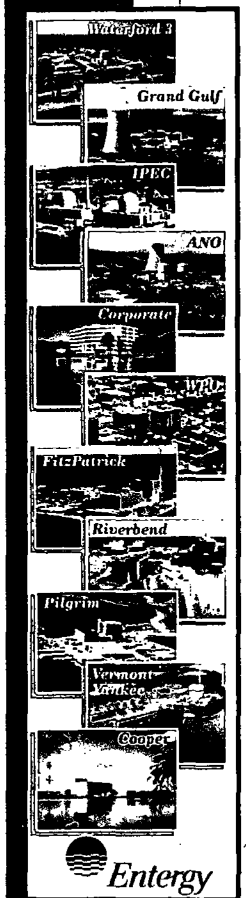
- Environmental effects on fatigue usage will be assessed consistent with the Generic Aging Lessons Learned Report, NUREG-1801, Rev. 1.

- If Option (2) becomes necessary, plant inspection program will be described in terms of the ten elements specified in Branch Technical Position RLSB-1.

- If Option (3) becomes necessary, repair or replacement will be in accordance with plant procedures that meet ASME Section XI requirements.

- Above actions will be incorporated into the Fatigue Monitoring Program.

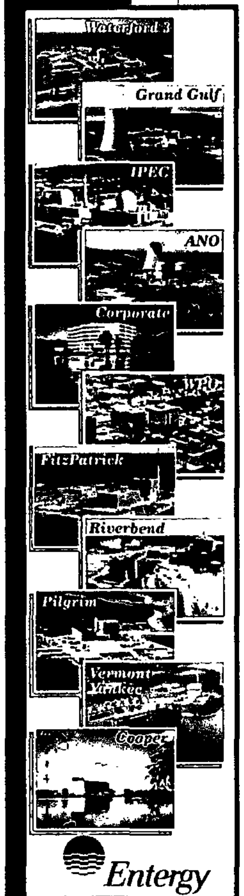
- The Fatigue Montoring Program will manage the effects of EAF in accordance with 10 CFR 54.21(c)(1)(iii).



Cost-Beneficial SAMAs

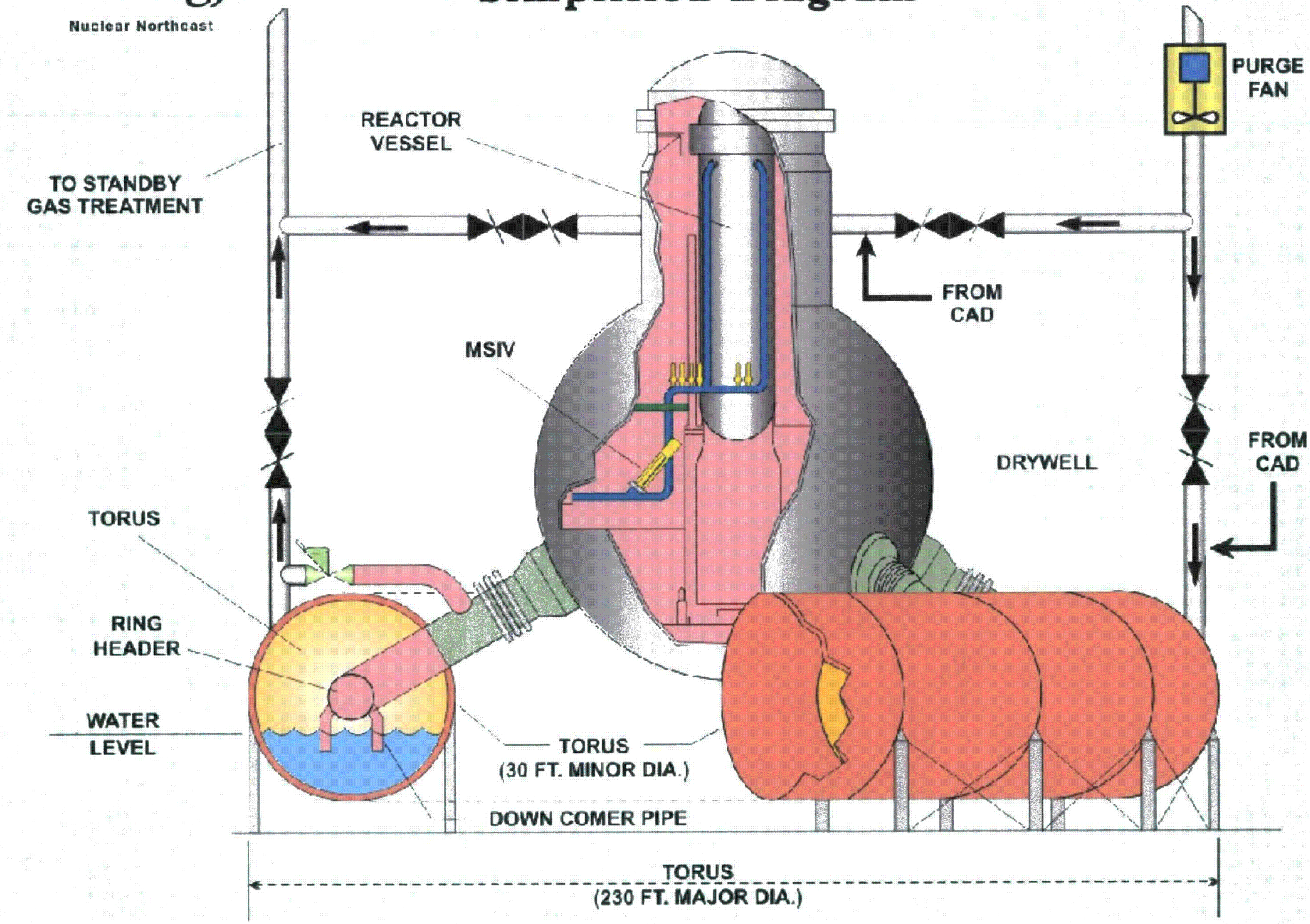
- Six Potentially Cost-Beneficial SAMAs Identified
- No Age-Related SAMAs
- Implementation will be evaluated using the plant cost-benefit analysis process

Presentation Topics

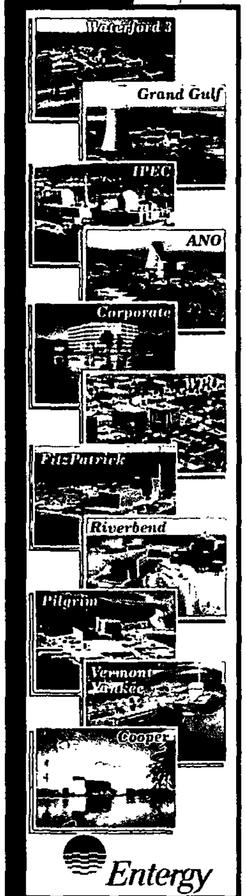


- Drywell and Torus Monitoring
- Torus Repair

Primary Containment System Simplified Diagram

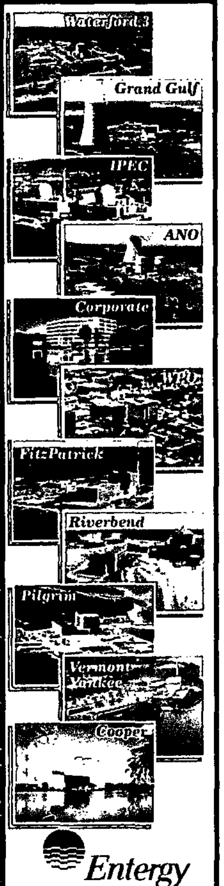


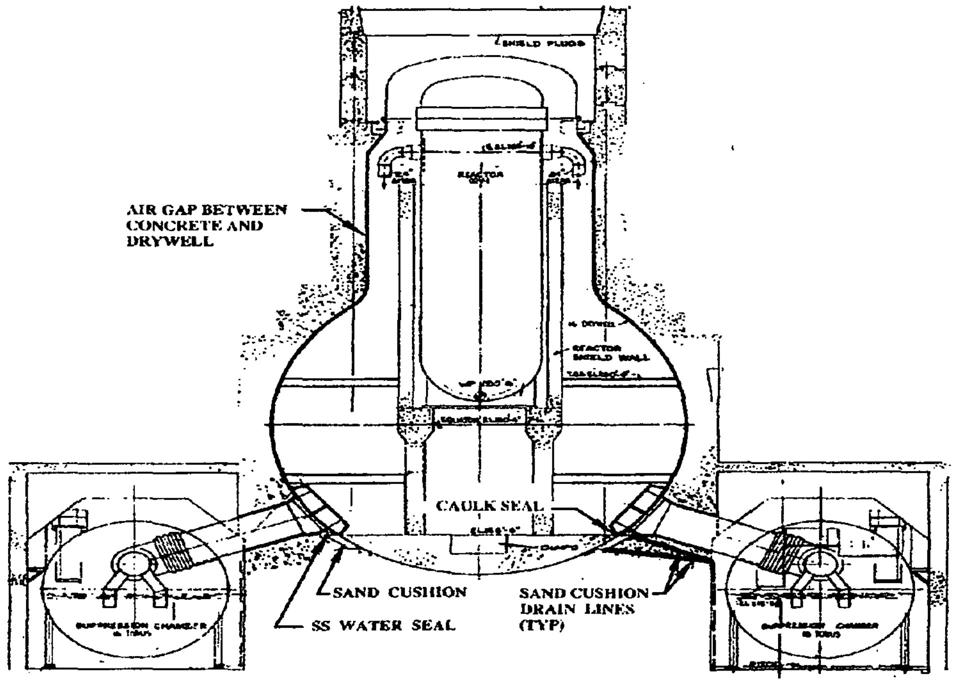
James A. FitzPatrick



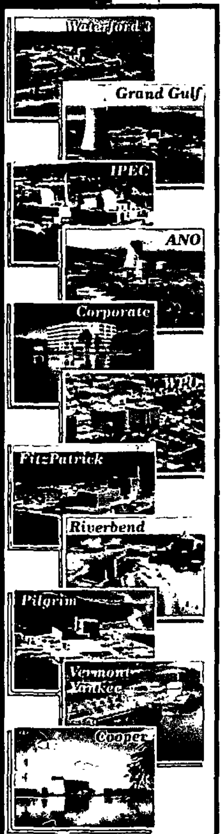
Drywell and Torus Monitoring

James A. FitzPatrick





PRIMARY CONTAINMENT DETAIL



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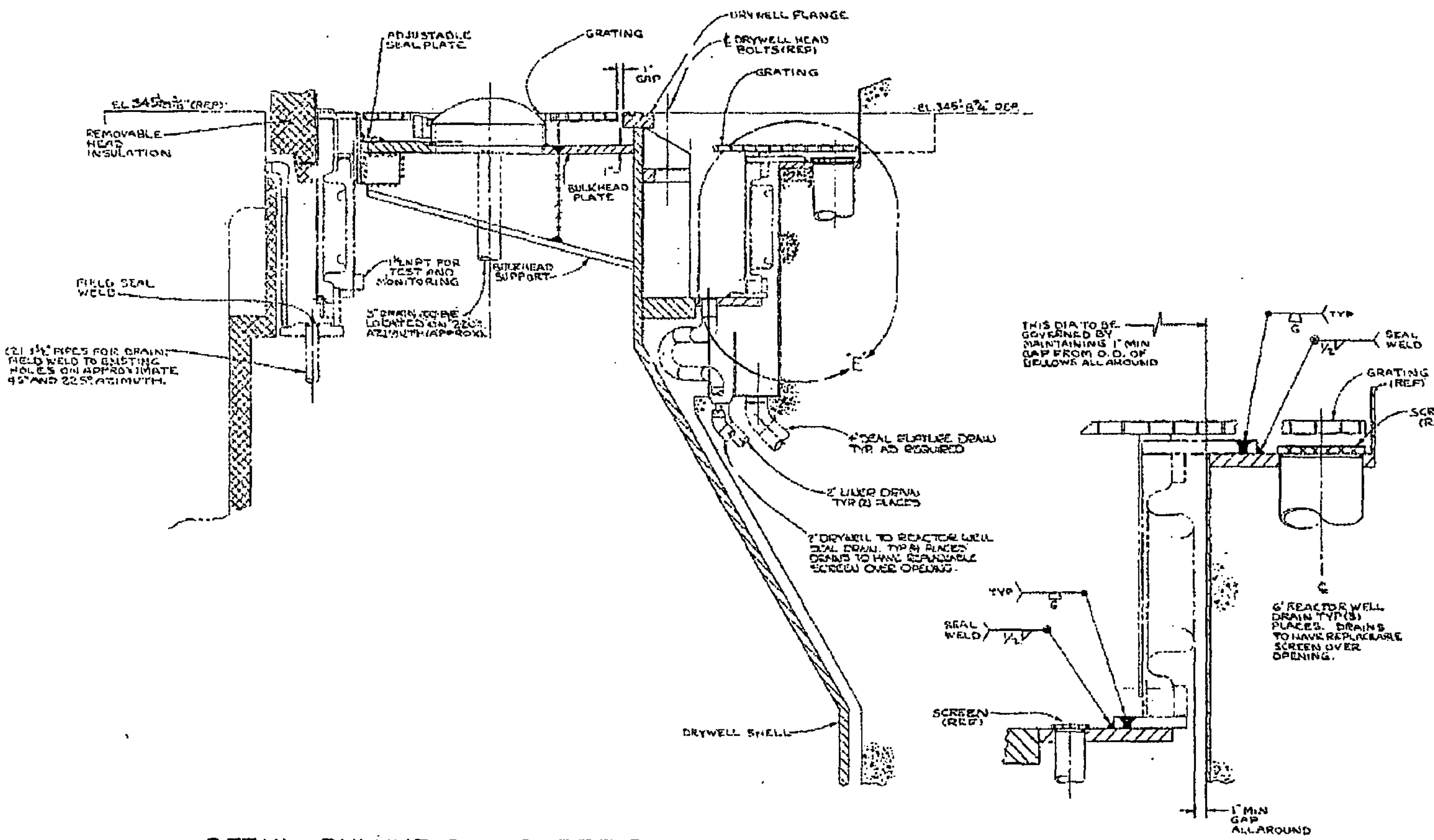
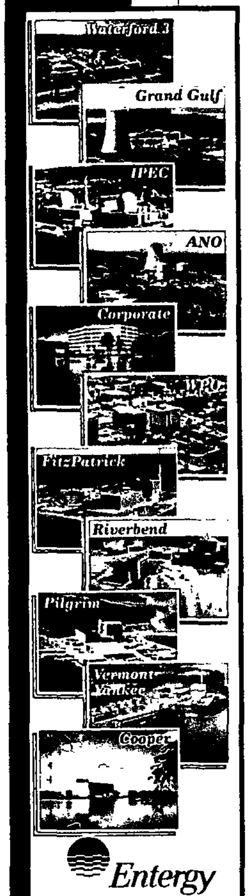
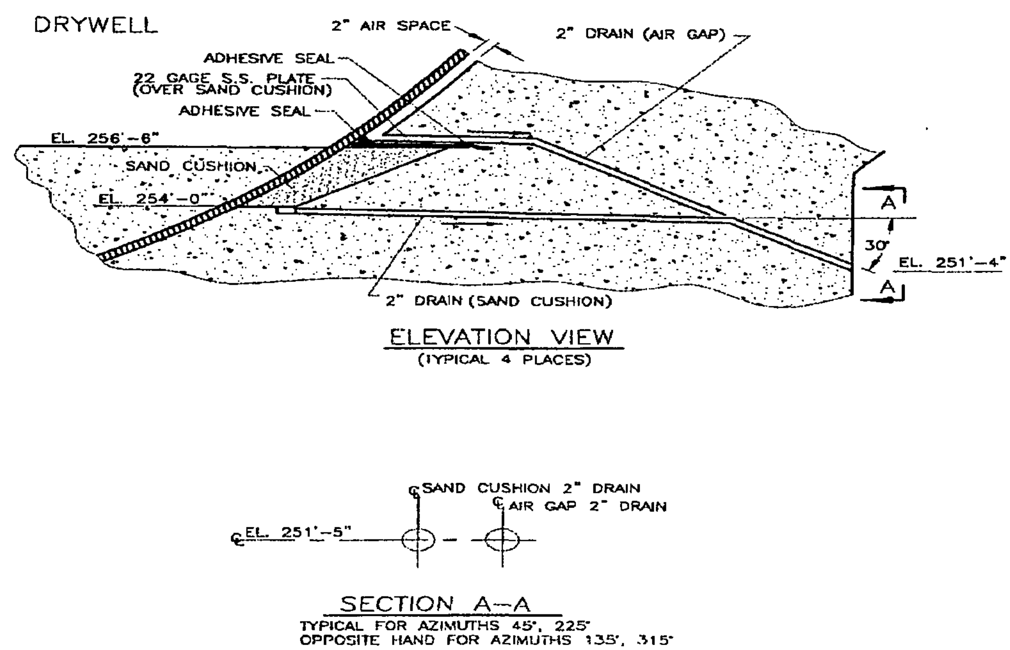


DETAIL–BULKHEAD AND REFUELING BELLOWS

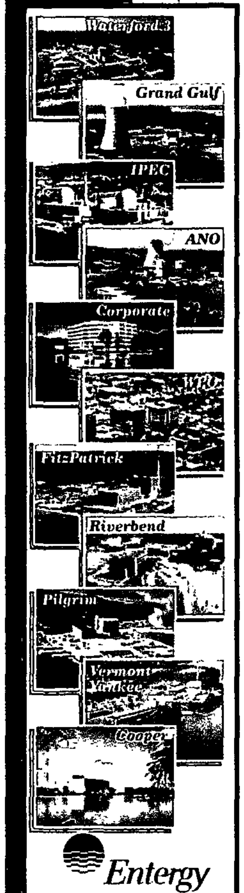
ENLARGED DETAIL "E"

James A. FitzPatrick





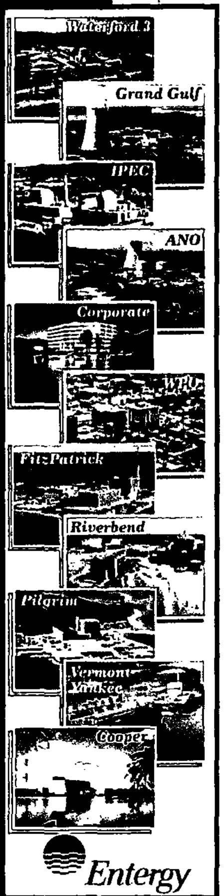
SAND CUSHION & AIR GAP DRAIN LINE DETAILS



Drywell Monitoring

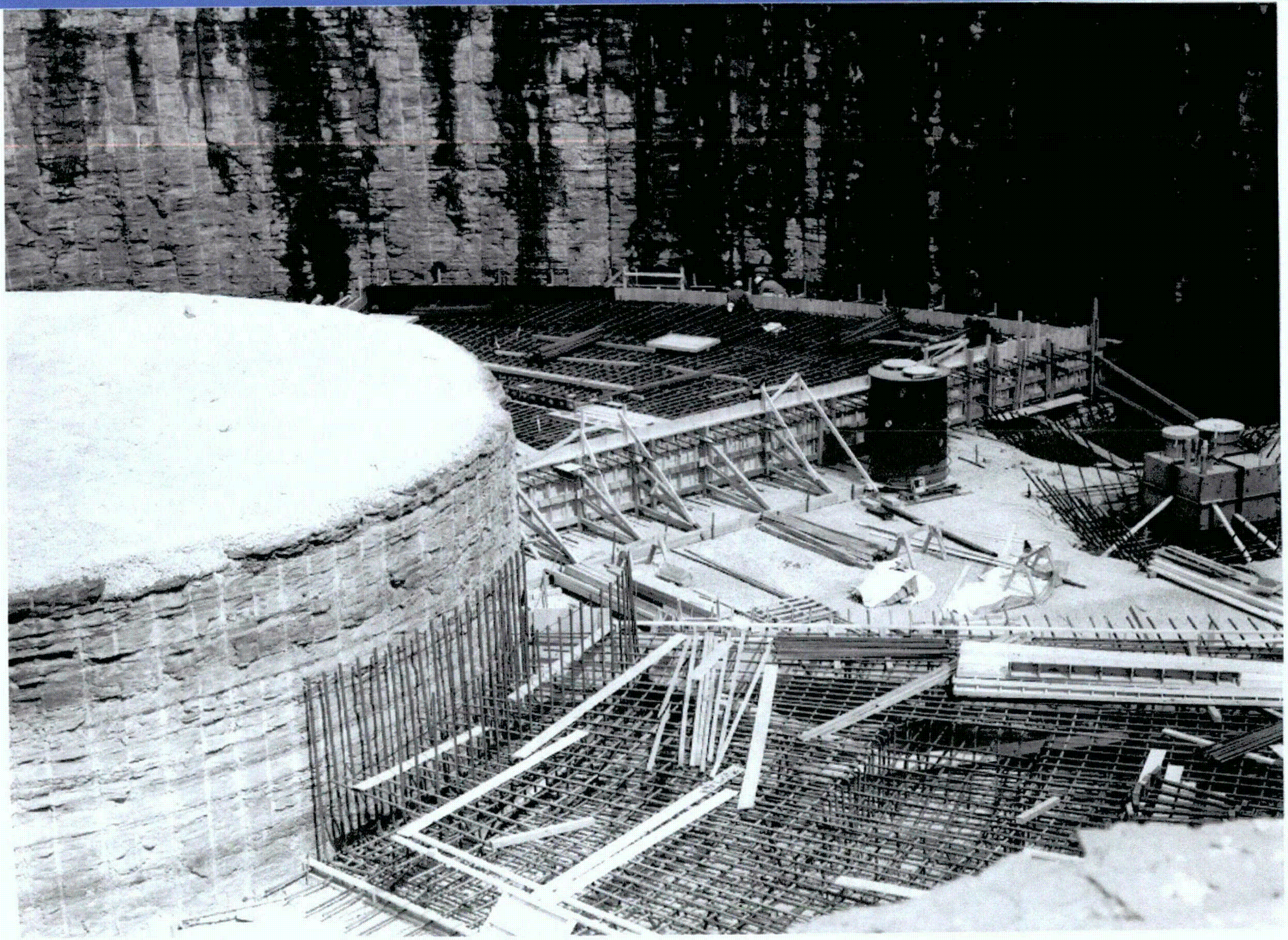
- Sand Cushion Inspections. No Evidence of Moisture (Boroscopic Inspection).
- Visual Inspection of Interior Drywell Caulk Seal.
- Drywell Interior Coating System (Carbozinc 11 and Dupont Corlar Epoxy) Inspection IAW IWE Program during RFO.

Torus Monitoring

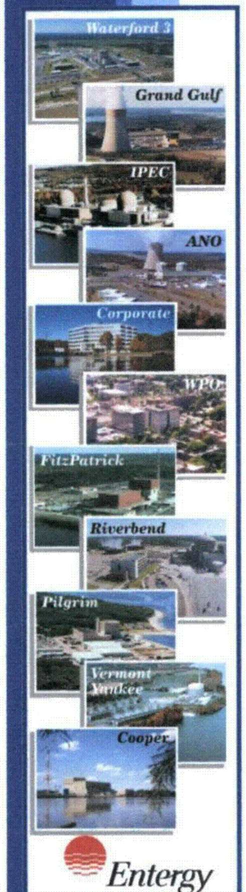


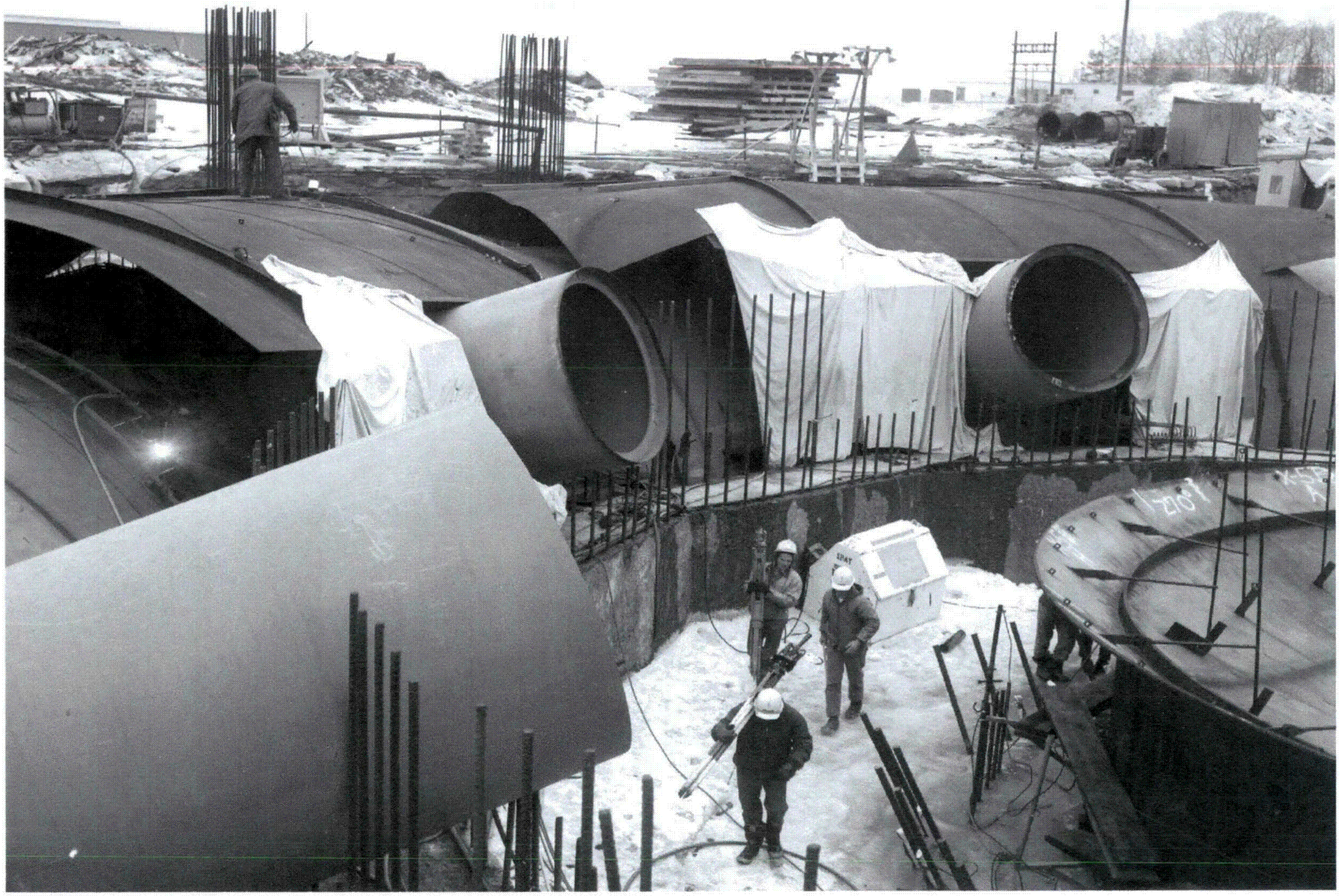
- Torus Interior Shell Inspection 1998 (Installation of ECCS Suction Strainers).
- Torus Interior Coating System (Carbozinc 11) inspected.
- Torus Interior/Exterior Inspected IAW JAF IWE Program.

Drywell Shell Construction Photo

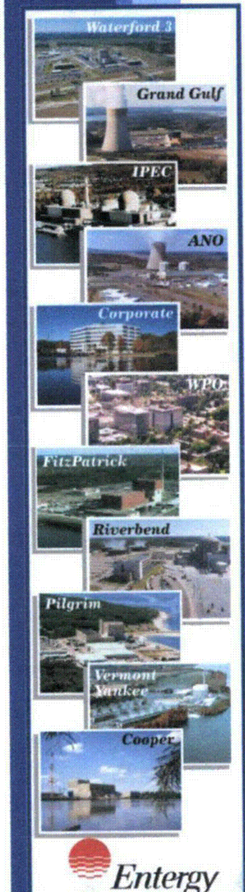


Drywell Shell Construction Photo





Drywell Shell Construction Photo



Drywell Shell Construction Photo

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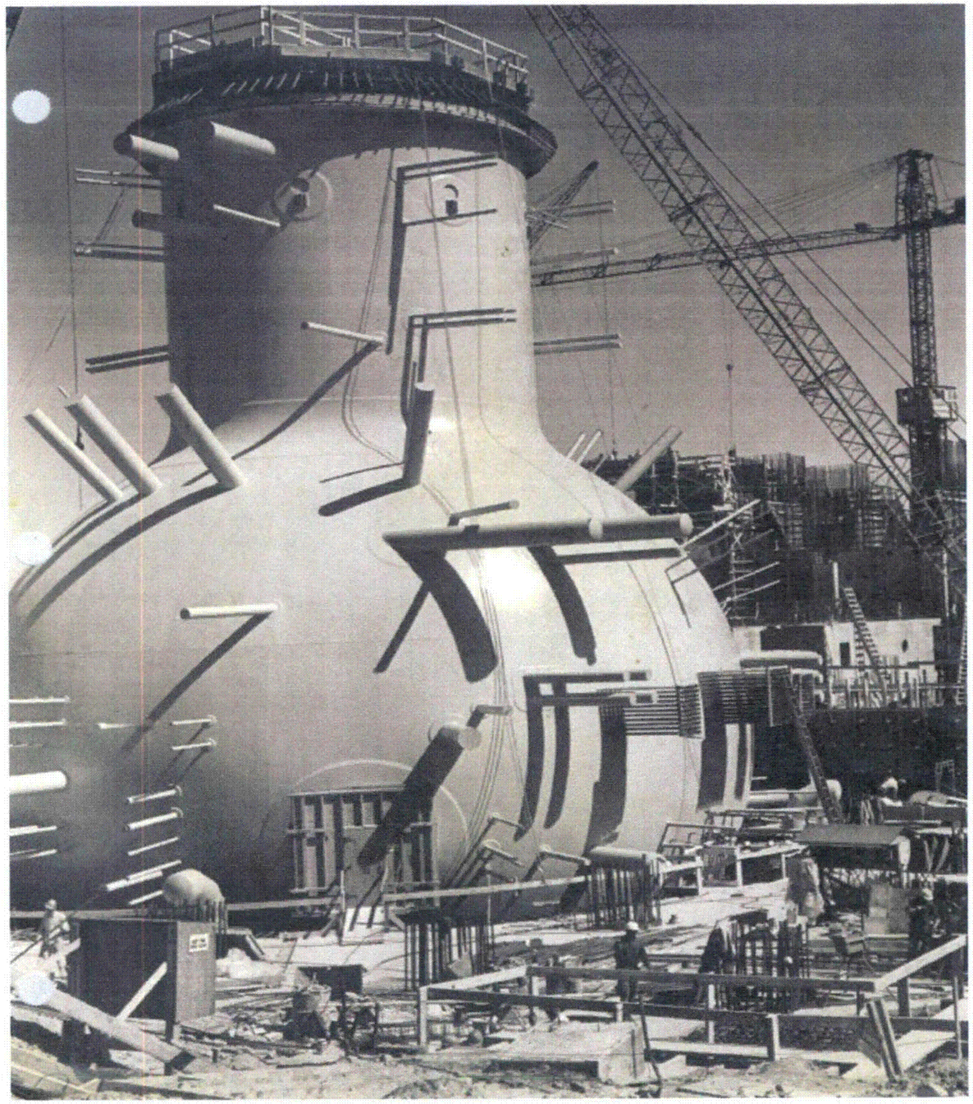

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Torus Repair

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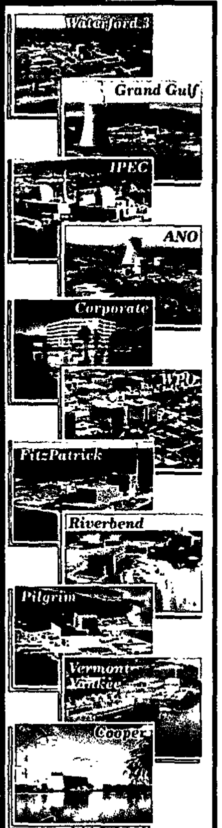

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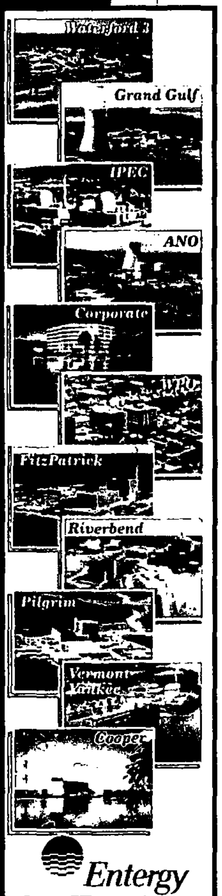
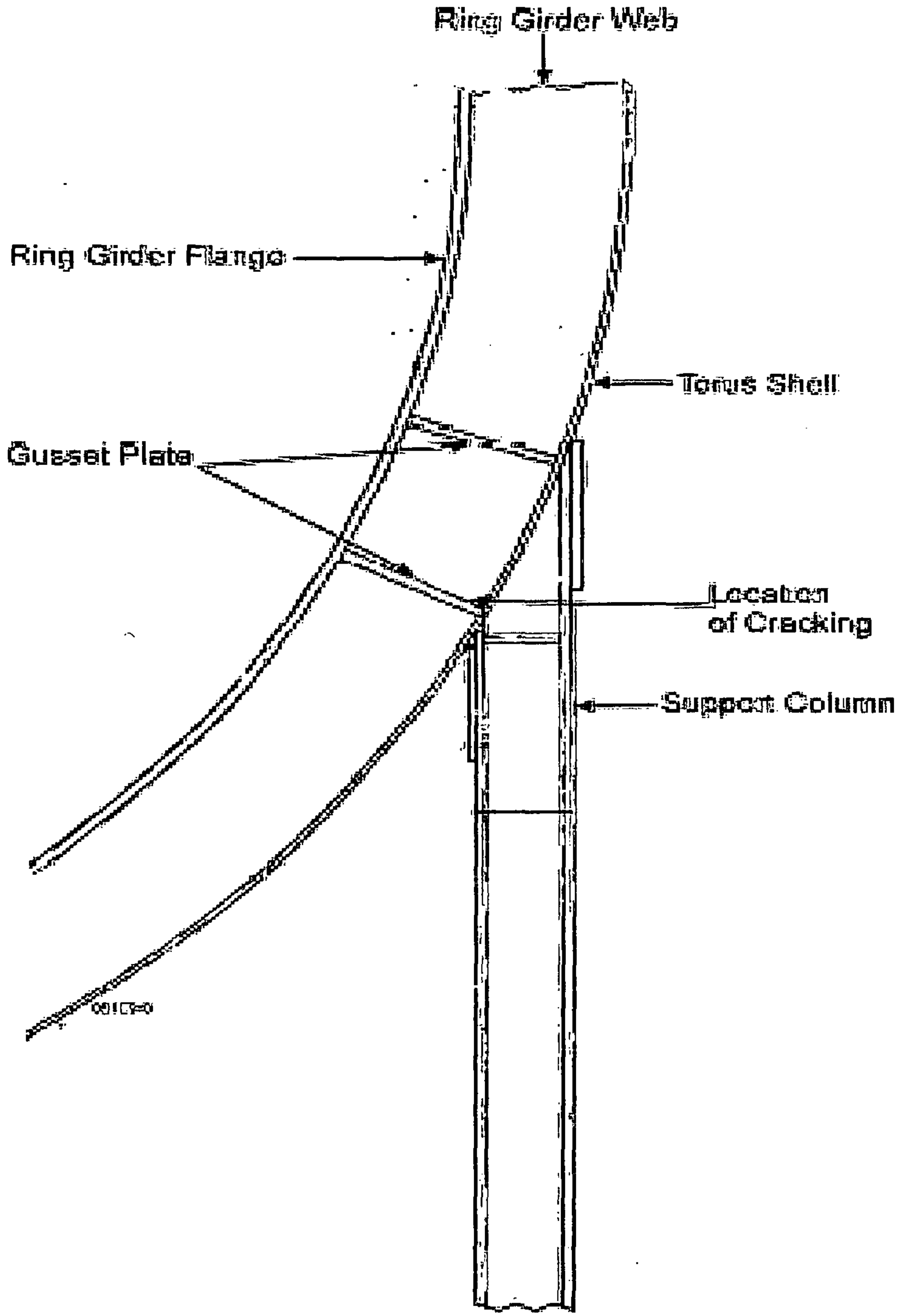
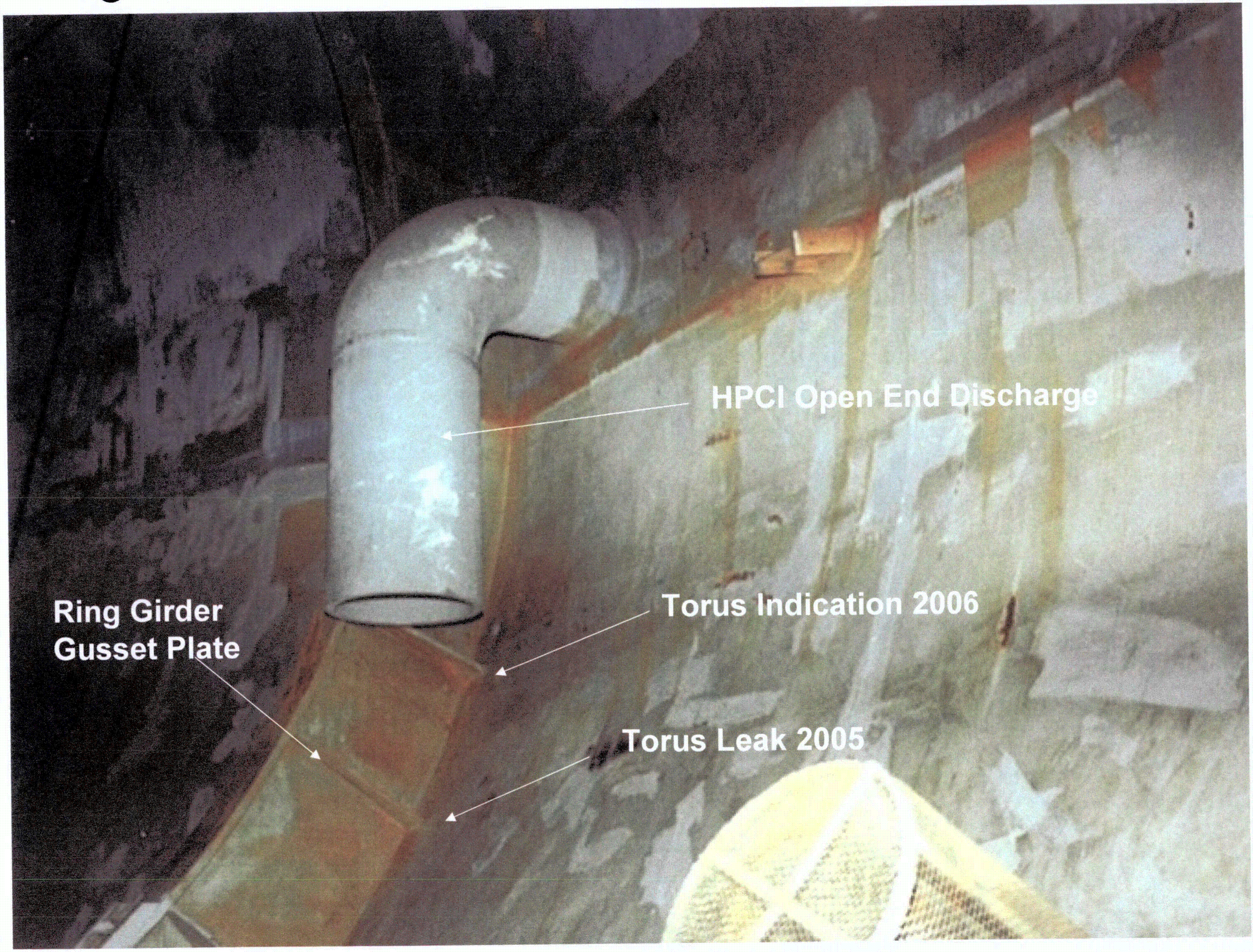
Torus Repair

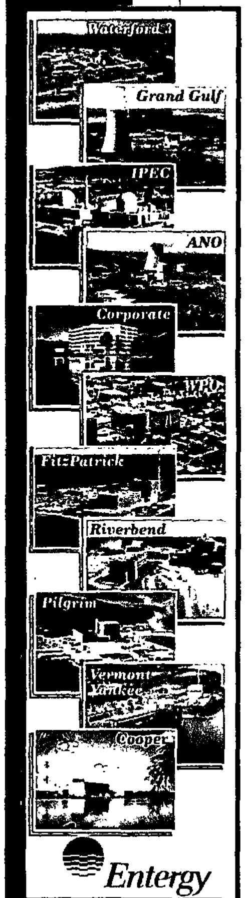
Torus Repair



- Torus shell through-wall leak reported in June 2005
- Leak was located in same bay as HPCI Steam Discharge pipe near ring girder gusset plate weld
- ASME Section XI code repair performed in July 2005 by removing the flaw and adding a circular repair plate
- Root cause of flaw was vibration fatigue from HPCI steam condensation oscillation loading

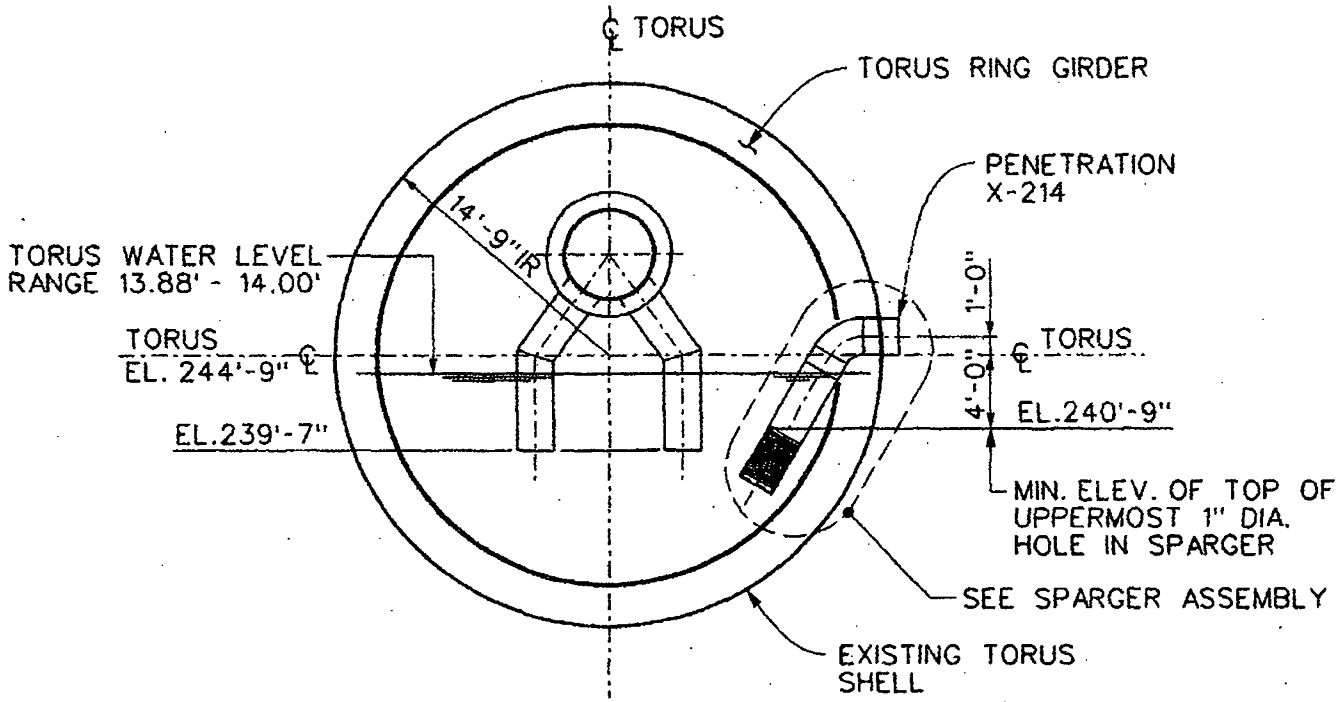

Ring Girder Web
Ring Girder Flange
Torus Shell
Gusset Plate
Location
of Cracking
Support Column


HPCI Open End Discharge
Ring Girder
Gusset Plate
Torus Indication 2006
Torus Leak 2005



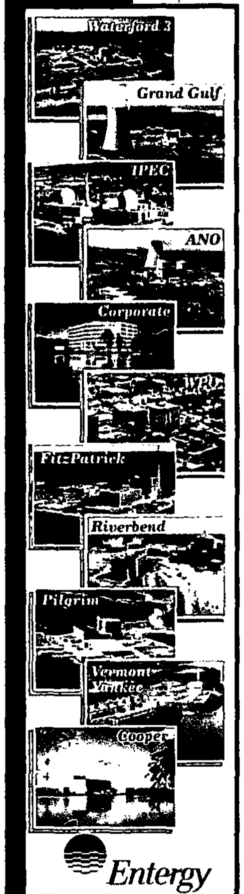
Torus Repair

- A HPCI Steam Exhaust Sparger assembly was added during refueling outage October 2006
- The sparger directs steam flow away from the Torus shell
- The sparger significantly reduces loads on the Torus shell from HPCI Steam condensation oscillation



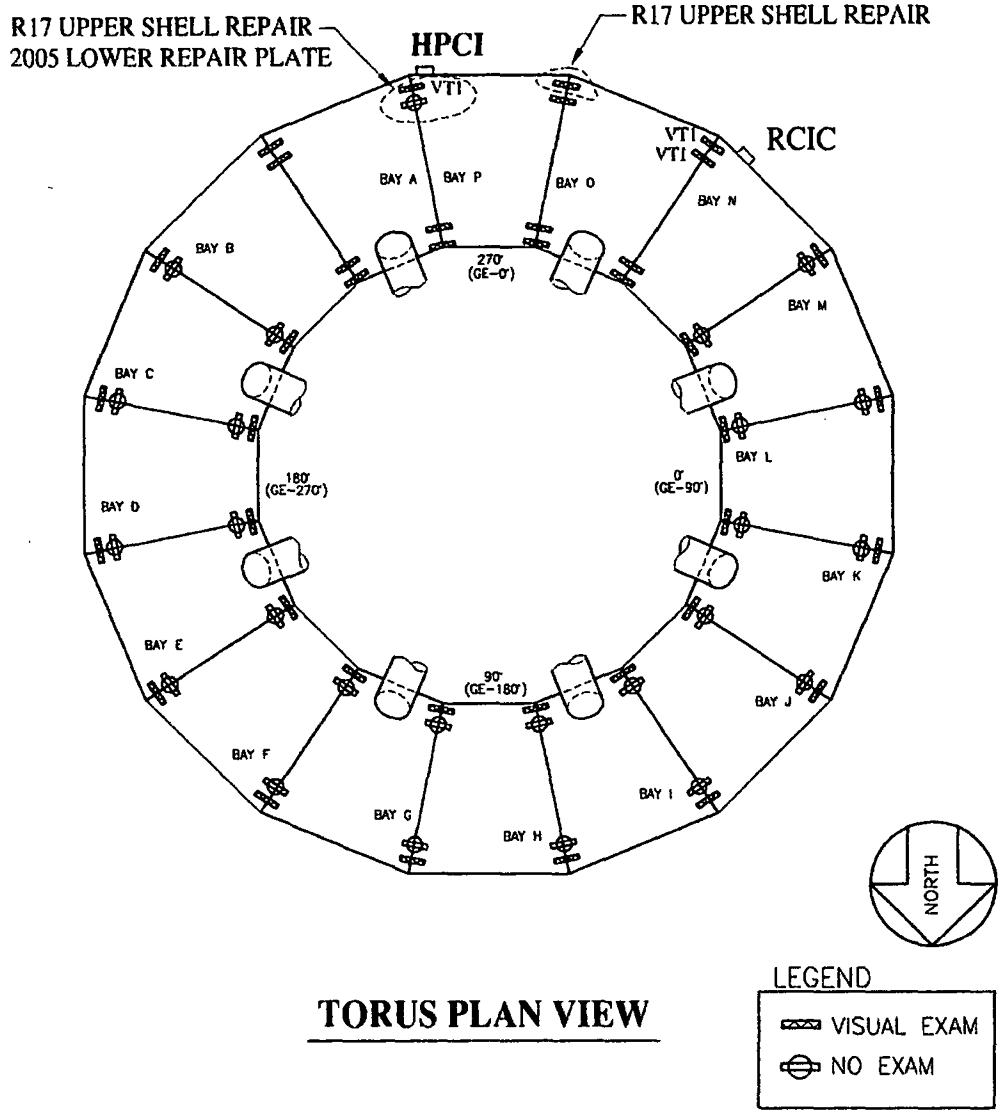
ELEVATION LOOKING EAST @ 270° AZIMUTH

SCALE: 1/8"=1'-0"



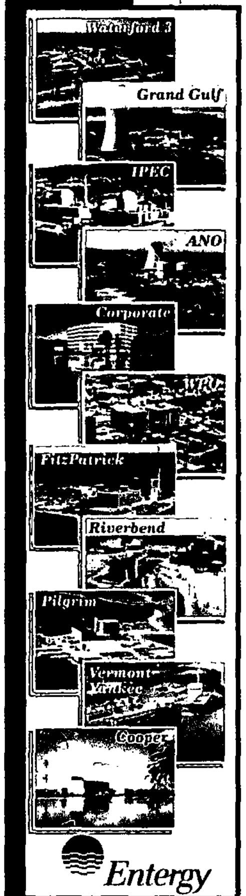
Torus Repair

- Extent of condition actions from Root Cause required additional shell exams during refueling outage October 2006
- ASME visual exams of similar ring girder gusset welds performed at HPCI and RCIC steam discharge locations
- General visual exams of similar ring girder gusset welds performed at several locations throughout the Torus
- Exam results reported shell base metal flaws at two additional locations in the HPCI discharge bay



TORUS PLAN VIEW

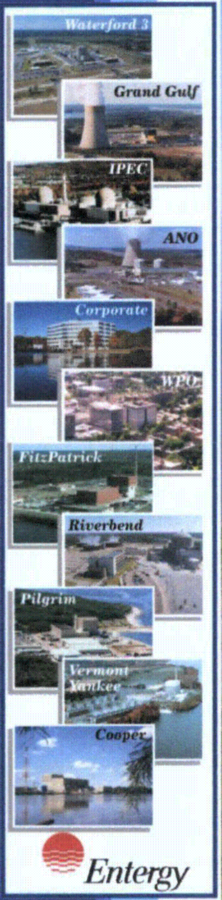
Torus Repair



- ASME Section XI code repairs were performed by grinding to remove the flaws and welding to restore configuration

- Review was performed to confirm the HPCI steam discharge loading also caused these flaws

Comments and Questions



James A. Fitzpatrick Nuclear Power Station License Renewal Safety Evaluation Report

Staff Presentation to the ACRS

Tommy Le, Sr. Project Manager
Roy Mathew, Audit Team Leader
Office of Nuclear Reactor Regulation
Glenn Myer, Inspection Team Leader, RI

September 5, 2007

James A. Fitzpatrick Nuclear Power Station
License Renewal Safety Evaluation Report

Staff Presentation to the ACRS

Tommy Le, Sr. Project Manager
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Office of Nuclear Reactor Regulation
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September 5, 2007

1

Introduction

- Overview
- Section 2: Scoping and Screening Review
- License Renewal Inspections
- Section 3: Aging Management Review Results
- Section 4: Time-Limited Aging Analyses (TLAAs)

2

Overview

- LRA Submitted by Letter - July 31, 2006
- GE BWR - MARK 1 Containment
- 2536 MWth, 881 MWe
- Op. License DPR-59, Expires October 17, 2014
- Located in Scriba, NY [on shore of Lake Ontario, 33 miles NW of Syracuse, NY]

3

Overview

- Two (2) Open Items
- No Confirmatory Items
- Three (3) License Conditions
- 118 RAIs Issued, 346 Audit Questions
- ≈83% Consistent With GALL Report, Revision 1
- 25 Commitments
- Additional Components Brought Into Scope

4

Review Highlights

- Scoping and Screening Methodology Audit
  - September 25 - 29, 2006
- AMP/AMR/TLAA Audit and Review
  - November 13-17, 2006
  - December 11-15, 2006
  - January 8-9, 2007
- Regional Inspections
  - April 9-13, 2007
  - April 23-27, 2007

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Section 2: Scoping and Screening Review

Section 2.1 - Scoping and Screening Methodology

- On-site Audit – September 25-29, 2006
  Staff Audit And Review Concluded That The Applicant's Methodology Satisfies The Rule (10 CFR 54.4(a) and 10 CFR 54.21)

Section 2.2 - Plant-Level Scoping

- No Omission Of Systems Or Structures Within The Scope Of License Renewal

6

1

Section 2: Scoping and Screening Review

Section 2.3 – Mechanical Systems

- 57 Mechanical Systems [26 BOP]
- 100% Reviewed
- BOP: Tier 1 Review: 10 Systems

  Tier 2 Review: 16 Systems
- 18 Miscellaneous Systems as 54.4.a(2)
- *Additional Components Brought Into Scope*

7

Section 2: Scoping and Screening Review, con't

Section 2.3 – Mechanical Systems

- *Examples of Components Brought Into Scope*
  - Yard Fire Hydrants (Fire Protection)
  - Screenwell Bldg Fire Suppression system
  - Water Spray System over MG Set and EDG rooms
  - Floor and Roof Drainage System & Non-Safety related components (Inspection team)
  - Others: Sight glass for Security Generator, Tubing for Fuel Oil System, Tubing &valve body for Service, Instrument & Breathing Air System, etc...

8

Section 2: Scoping and Screening Review

Section 2.4 – Containment, Structures, and Supports

- No Omission Of Structures Or Supports Within The Scope Of License Renewal

Section 2.5 – Electrical and Instrumentation & Control

- No Omission Of Electrical And Instrumentation & Control Systems Components Within The Scope Of License Renewal

9

Section 2: Scoping and Screening Summary

- *The Applicant's Scoping Methodology Meets The Requirements Of The Rule (10 CFR Part 54)*
- Scoping And Screening Results, As Amended, Included All SSCs Within The Scope Of License Renewal And Subject To AMR

10

License Renewal Inspections

Glenn Meyer
Richard Conte
Region I

11

Scoping and Screening

- 54.4(a)(2) - non-safety SSCs whose failure could impact safety SSCs
- Spatial and Structural Interactions
- LRA Drawings and procedures reviewed
- Plant walkdowns performed
- Some components or portions of systems needed to be added to scope

12

Scoping and Screening Conclusions

- **Spatial interaction - Acceptable**
- **Structural interaction - Acceptable**
- **Scoping and screening acceptable for license renewal**

13

Aging Management

- Reviewed 22 AMP programs
- Reviewed programs, evaluations, and records
  - Program procedures
  - Operational experience information
  - Corrective actions on prior plant issues
- Interviewed cognizant personnel
- Performed plant walk downs – only one issue noted

14

Aging Management Conclusions

Aging Management Programs support conclusion that aging effects will be managed

15

Overall Conclusions

- **Scoping, screening and aging management programs are acceptable.**
- **Region I does not see any inspection impediments to renewing the operating license.**

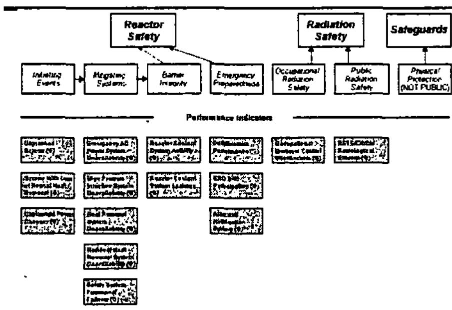
16

Current Performance

- **Licensee Response Column (Column I) of the NRC's Action Matrix – Green PIs and Findings**
- **No cross-cutting issues**
- **Reactor Oversight Process baseline inspections**

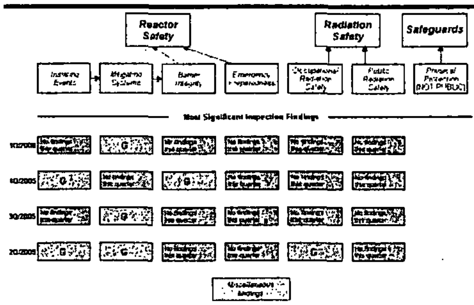
17

Performance Indicators



18

Inspection Findings



19

Aging Management Program (AMP) Audit and Review

- Total 36 AMPs
  - 26 existing AMPs
  - 10 new AMPs
- GALL Report Consistency
  - 10 Consistent
  - 20 Consistent with exceptions/enhancements
  - 6 Plant Specific

20

AMP/AMR/TLAA AUDIT AND REVIEW

- 346 Audit Questions
- All Questions Except Two were Resolved
  - 2 Questions Converted to RAIs
  - Fifty-five of the Questions Resulted in Revisions to the LRA
- 25 Commitments at the End of the Audit

21

AUDIT AND REVIEW

- Audit Summary (ADAMS Accession No. ML071580047)
  - A pilot of new way to document audit information
  - Publicly Available, Issued on June 19, 2007
  - Audit Summary Includes :
    - Audit and Review Results
    - Audit and Review Q&A Database
    - Reviewers' Evaluations/Comments
    - List of Documents Reviewed by the Audit and Review Team

22

Aging Management Review

- 100% Review
  - 21 plant systems and 44 Auxiliary & Miscellaneous systems in scope for 10 CFR 54.4 (a)(2)
  - 4 structural components & commodity groups
  - 6 electrical commodity groups

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Section 3: Aging Management Review - Overview

- 3.1 Reactor Vessel, Internals and Reactor Coolant System
- 3.2 Engineered Safety Features Systems
- 3.3 Auxiliary Systems
- 3.4 Steam and Power Conversion Systems
- 3.5 Structures and Component Supports
- 3.6 Electrical and I&C Components

24

Aging Management Review– Drywell Shell

- Two Aging Management Programs
  - Containment Inservice Inspection Program
  - Containment Leak Rate Program
- Consistent with the Staff Interim Guidance LR-ISG-2006-01
- No leakage identified in the vicinity of the sand cushion drain line
- Water leakage monitoring (each refueling)
  - refueling seal bellows
  - drywell air gap drains
  - sand pocket drains
  - functional checks on the alarm system

25

Aging Management Review of Electrical and I&C Components

- Six Commodity Groups Reviewed
- Commitment 24 - Implement the Bolted Connections Program consistent with the proposed revision to GALL XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements."
- Commitment 25 - Implement aging management for the 115 kV Oil-Filled Cable System that will be controlled by the following AMPs (In response to RAI 3.6.2-1)
  - External Surfaces Monitoring Program
  - Oil Analysis Program
  - Periodic Surveillance and Preventive Maintenance Program

26

Section 4: Time-Limited Aging Analyses (TLAA) - Overview

- 4.1 Identification of TLAA
- 4.2 Reactor Vessel Neutron Embrittlement
  - Open Item 4.2.1-1
- 4.3 Metal Fatigue
  - Open Item 4.3.3-1
- 4.4 Environmental Qualification Analyses of Electrical Equipment
- 4.5 Concrete Containment Tendon Prestress [N/A]
- 4.6 Containment Liner Plate, Metal Containment, and Penetrations Fatigue Analysis

27

Section 4: Time-Limited Aging Analyses (TLAA), Cont.

- 4.7 Other Plant Specific TLAAs
  - 4.7.1 Recirculation valves
  - 4.7.2 Fatigue Crack growth Analysis [UFSAR 16.3.2.2]
  - 4.7.3 TLAA in BWRVIP Documents
  - 4.7.4 Assessment of Plant-specific Fatigue Flaw Growth and Fracture Mechanics Evaluations

28

Neutron Fluence

- <u>Open Item 4.2.1-1</u>
  - Calculation of Neutron Fluence not in accordance with Reg. Guide 1.190
    - Fluence values were based on dosimeter measurements
    - Flux uncertainties reported in the 25 to 30 percent which are outside of recommended range
    - Result: Above Lead to Open Item 4.2.1-1

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Section 4.2: Reactor Vessel Neutron Embrittlement

- Six TLAAs Affected by Neutron Fluence Cal
  - Reactor Vessel Fluence – OI 4.2.1-1
  - Pressure-Temperature Limits – sOI 4.2.2-1
  - Charpy Upper Shelf Energy – sOI 4.2.3-1
  - Adjusted Reference Temperature – sOI 4.2.4-1
  - Reactor Vessel Circumference Weld Inspection Relief – sOI 4.2.5-1
  - Reactor Vessel Axial Weld Failure Probability – sOI 4.2.6-1
- One AMP Affected by Neutron Fluence

  Reactor Vessel Surveillance Program – sOI B1.24-3

30

Section 4.3: Metal Fatigue

- Environmentally-adjusted CUF values for the following projected to be above 1.0 for the PEO
  - RPV shell
  - RPV FW nozzle safe end
  - RPV recirculation inlet nozzle thermal sleeve
  - RPV recirculation outlet nozzle
- The applicant amended the LRA to include Commitment No. 20
- Commitment # 20 Will Ensure That Either
  - Projected 60 yrs Cycles Enveloped by Design Cycles
  - Refined CUF ≤ 1 for PEO
  - Aging Effects Will be Managed for the Components
  - Repair Or Replace the Affected RPV Locations

31

Section 4.3: Metal Fatigue Con't

- Open Item 4.3.3-1
  - RAI 4.3.3-1 - Applicant to identify which option or options under LRA Commitment No. 20 would be used to satisfy the commitment when implemented and, for each option selected to meet the commitment, to provide a sufficient detailed description of the methodology that would be used *to satisfy the option.*
  - The staff's determination on the acceptability of the TLAA on environmentally-assisted fatigue is pending submittal of the applicant's response to RAI 4.3.3-1 and the staff's review of the response to this RAI.

32

Section 4.4: Environmental Qualification (EQ) of Electrical Equipment

- Applicant's EQ Program consistent with GALL AMP X.E1, "Environmental Qualification of Electrical Equipment"
- Staff Concluded The EQ Program Is Adequate To Manage The Effects Of Aging On The Intended Function Of Electrical Components
- The Staff Accepted the Evaluation in Accordance with 10 CFR 54.21(c)(1)(iii)

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Conclusions

- **On the basis of its review of the James A. FitzPatrick LRA, with the exception of Open Item (OI) 4.2.1-1, and OI 4.3.3-1, the staff determines that the requirements of 10 CFR 54.29(a) have been met.**

34

Questions

35