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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

PLANT LICENSE RENEWAL SUBCOMMITTEE

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TUESDAY,

NOVEMBER 4, 2003

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 12:30 p.m., Mario V. Bonaca, Chairman, presiding.

COMMITTEE MEMBERS:

MARIO V. BONACA, Chairman

F. PETER FORD, Member

GRAHAM M. LEITCH, Member

STEPHEN L. ROSEN, Member

GRAHAM B. WALLIS, Member

ACRS STAFF PRESENT:

MARVIN D. SYKES

NRC STAFF PRESENT:

RUSSELL J. ARRIGHI, NRR

BARRY ELLIOT, NRR

FRANK GILLESPIE, NRR

SAM LEE, NRR

MICHAEL MODES, Region I

JONATHAN ROWLEY, NRR

ALSO PRESENT:

GERRY GEIKEN

GEORGE HERRICK

JARRED JACKSON

MARY ELLEN McGRAW

ROBERT C. MECREDY

DAVID WILSON

GEORGE WROBEL

A-G-E-N-D-A

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

12:32 a.m.

CHAIRMAN BONACA: The meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards, Subcommittee on Plant License Renewal.

I am Mario Bonaca, Chairman of the Subcommittee.

ACRS members in attendance are Graham Wallis, Peter Ford, Steve Rosen and Graham Leitch.

Marvin Sykes is the designated federal official for this meeting.

The purpose of this meeting is to discuss the license renewal application for the Robert E. Ginna nuclear power plant and the associated NRC separate evaluation report with open items.

During this meeting we will hear presentations by the applicant, Rochester Gas and Electric and the NRC Office of Nuclear Regulatory Regulation.

The Subcommittee will gather information, analyze relevant issues and facts and formulate report positions and actions as appropriate for deliberations by 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* on October 22, 2003. We have received no other written comments or requests for time to make oral statements from members of the public regarding today's meeting.

A transcript of the meeting is being kept, and will be made available as stated in the *Federal Register* notice.

It is requested that speakers first identify themselves and then 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. LEE: Yes. My name is Sam Lee.

CHAIRMAN BONACA: Lee.

DR. LEE: I am the Section Chief in the License Renewal Program. Dr. PT Kuo, Program Director, she is not able to here today. And we expect our Deputy Division Director.

CHAIRMAN BONACA: Mr. Gillespie?

DR. LEE: Mr. Frank Gillespie, he should be here shortly.

CHAIRMAN BONACA: Okay. But you can start the meeting?

DR. LEE: I will start. I would like to you know, I guess, for ACRS continue support of the license renewal activities.

And there's a lot of activity going on in License Renewal. I guess, about a half an hour ago Jim Dyer just signed the renewal license for Fort Calhoun. So now we have, I guess, with that 21 approved units for license renewal and 16 under review.

CHAIRMAN BONACA: Okay.

DR. LEE: With that today, the purpose today is to discuss the staff review of the Ginna application for license renewal. And the Project Manager is Russ Arrighi, and he is supported by John Rowley. And we have eight open items, and John is going to go over the status with you.

And I guess we will turn over to RG&E, the licensee, to make their presentation.

MR. WROBEL: Shall I start?

DR. LEE: Yes.

MR. WROBEL: Okay. My name is George Wrobel. I am the license renewal project manager for Ginna Station. I'd like to have the other

people that worked on the license renewal project introduce themselves from RG&E.

MR. HERRICK: George Herrick, license renewal engineer from RG&E.

MR. MECREDY: Bob Mecredy, Vice President of Nuclear Operations, RG&E.

MR. WILSON: David Wilson, license renewal engineer at RG&E.

MR. GEIKEN: Gerry Geiken, general engineer at RG&E.

MS. McGRAW: Mary Ellen McGraw, mechanical engineer at RG&E.

MR. JACKSON: Jarred Jackson, electrical engineer support at RG&E.

MR. WROBEL: Thank you.

This is the plan we're talking about, it's the review. The contents of today's presentation with RG&E. We are going to go over the background and history of the plant a little bit. Talk about some of the unique features, issues that are in the works now. Some current issues.

MR. LEITCH: Just while we're getting that set up, George, I was looking at the photograph. It doesn't show so well on the one that you have, but there is a odd looking building, I

guess, in the foreground of the picture. I was just curious as to what that is? It's a brick building, is it? I was just curious as to what --

MR. WROBEL: The simulator building is here.

MR. LEITCH: I was asking about the one to the right.

MR. WROBEL: That's the training center.

MR. LEITCH: Oh, that's the training center?

MR. WROBEL: That's the beginning of the training center. There's been an addition put on since then.

MR. LEITCH: I see.

MR. MECREDY: That was the original visitor center, information center on the site. The first structure on the site.

MR. LEITCH: Okay. Thank you. Just a curiosity question.

MR. WROBEL: Okay. We thought we'd talk about some of the current issues of interest right now. I know there's a lot of the interest in the cracked vessel head and the bottom head inspections that we did this past outage. And then some issues on the containment recirculation sump.

If there's any other current issues that could be considered, we can talk about those also.

I want to talk a little bit about how we put the licensed renewal application together. And then talk about some of the specific results, particularly in the TLAAs programs. We have several commitments that we have made that we'll implement in the future. And we do have a couple of open items to be talked about mostly by the NRC.

So, back to the background and history. Most of you probably know, it's a Westinghouse two loop 1520 megawatt PWR, upstate New York.

The initial license was granted in September 18, 1969. We were one of the Systematic Evaluation Program plants. We'll talk about that on the next slide a little bit.

We did have our provisional operating license to full-term operating license that was as a result of the Systematic Evaluation Program. It started in '72 and ended in '84; a 12 year process then. So license renewal seems pretty quick now.

We also had our CP-OL recapture that was done. Construction permit was 41 months for Ginna. And that changed our operating license from 4-25-06 to the current 9-18-09.

MR. LEITCH: George, I'm a little confused by the history, I guess. I don't quite understand the process that was used at that time. Basically my question is the 40 years dates from 1969, not 1984, is that correct?

MR. WROBEL: That's correct.

MR. LEITCH: Yes.

MR. WROBEL: The 1984 was when we got our full-term operating license. We were operating under a provisional operation license, which is how we got into the Systematic Evaluation Program in the first place.

MR. LEITCH: I see.

MR. WROBEL: So we had, I think it was year-to-year, we got the provisional operating license extended.

MR. LEITCH: Oh, okay.

MR. WROBEL: And then since then -- so I guess we could have just stayed with that forever, continued forever.

MR. LEITCH: Yes. Yes.

MR. WROBEL: And the recapture was just the construction period.

MR. LEITCH: Construction period, yes.

MR. WROBEL: Some of the major projects

that we've had Ginna Station, there were a lot of them before '96. But the more recent ones, we replaced our steam generators in 1996. One of the side benefits of that was that we were able to reduce our TF, which has helped in subsequent issues from 573½ down to 561 currently that we're operating at.

We were, I believe, the first Westinghouse plant to convert to improved standard technical specifications. We did that in 1996 also.

DR. WALLIS: Did you have power uprates, totally new ones?

MR. WROBEL: The only power uprate that we had was from the initial 1300 megawatts in 1520. We have not had one since then.

In 1999 as part of the reactor vessels internal inspection, we did a baffle-bolt inspection. We inspected a large number of the baffle bolts and we replaced enough to -- there was plant specific analysis done by Westinghouse and we added a lot of baffle variables to the internals.

And then this year we just finished replacing our reactor vessel head.

CHAIRMAN BONACA: This thing with the baffle-bolt.

MR. WROBEL: Okay.

CHAIRMAN BONACA: You did that as a replacement. Now, if I remember in the application you stated you don't have to make any further inspections of the bolts?

MR. WROBEL: Well, we feel at this point that with the number of bolts that we put on and the very, very small number of failures that we experienced, I believe it was less than one percent of the bolts that we evaluated actually were degraded.

Between that and the fact that we have link-before-break completed for all of our 10 inch lines. So the next larger line that does not have link-before-break analysis on the primary system is a 4 inch line. So the forces resulting from that with the number of new bolts we have and the number of bolts that we inspected that were good, we don't believe that we need to do any additional work in baffle-barrel bolt inspections and/or replacement. That's our current position.

CHAIRMAN BONACA: So no further inspections? And we'll hear from the staff later on? Yes. During your presentation, that's fine.

MR. WROBEL: Okay.

CHAIRMAN BONACA: Let's remember that. Okay.

MR. WROBEL: Okay. Again, we replaced our reactor vessel head with the Inconel 690 penetrations including -- and we also added new control rod drive mechanisms. That was just completed in 2003, last month.

And I guess it's not a background/history, but we do anticipate selling the plant in the middle of next year.

I said I wanted to talk a little bit --

MR. LEITCH: Has a deal been struck and it's just a matter of implementation or is --

MR. WROBEL: It's not struck yet. The bids are due mid-November.

MR. LEITCH: I see. Thank you.

MR. WROBEL: Systematic Evaluation Program has got an interesting program that developed.

All of the plants that have original operating licenses and I believe a couple of the older plants that might have had full term operating license, we're evaluated under what's called the Systematic Evaluation Program which began in 1977. The project there was, was to review Ginna against

the then current Standard Review Plan, which is 75087. If you look at that compared to the current 0800, they're pretty comparable. So it's almost a review against the current Standard Review Plan.

It wasn't against the whole plan. There were 92 risk topics that were reviewed. Sometime or later, whenever, if you want to know what the topics were, I can highlight those also. But there was pretty extensive review of the plant against the Standard Review Plan.

And what happened there is that we really ended up with a very good short licensing basis. We got SERs on 92 topics, and some of the topics like seismic had multiple SERs written against them because there were structures, systems, tanks. So our FSAR was substantially upgraded with all the SERs that we out of the Systematic Evaluation Program. So it was a major benefit. It helped us define our current licensing basis and, therefore, helped us to define which structure systems and components would be in the scope of license renewal because we had such good documentation. It made scoping much easier.

CHAIRMAN BONACA: The reason why I asked the question to put on the agenda was, I'd like to

understand what changes you have to make physically to the plant, if any. For example, other SEP plants, they were plants that started up without any CCS system, without low-pressure injection systems. You know, Conn Yankee was one. Without safety injection tanks.

MR. WROBEL: Yes. We kind of lucked out there. We had all of those systems, but we did make some improvements in the systems. Many of the changes that we made were related to natural phenomena.

The Ginna Station design for tornadoes, for example, we don't get many. We're stuck with snow a lot, but we don't get many tornadoes and so the tornadoes design was almost none existent. We beefed up critical structures for tornado protection. We did an extensive review of the seismic analysis of Ginna. We made a quite a few changes both as a result of Bulletin 7902 and 14 NSEP. So we made quite a few seismic modifications to Ginna.

Flood protection, quite a bit of flood protection. And we relooked at high-energy line breaks both inside and outside containment. We changed the definition of high-energy and moderate-

energy consistent with the O'Leary letter, the '73 O'Leary letter where if it was either 212 or 200 pounds, it became a high-energy line. So that added some additional lines like steam heating lines into the scope of high-energy lines. And we did it both inside and outside containment. And we made a far number of modifications to improve separation from physical effects.

Those are the main ones.

CHAIRMAN BONACA: Well, for example, I was reading through that you have a two-train auxiliary feedwater system. And you have a separation between the two of them. And for SEP purposes you could not exclude the possibility that an external event would eliminate with a common cause both trains.

MR. WROBEL: Yes, that was --

CHAIRMAN BONACA: So you have a reliance on a third train now that is an independent train that ran somewhere else. And, you know, my question when I was reading was how do you treat methodology wise, how do you treat this third train? I mean, is it self-degrading.

MR. WROBEL: Yes, it's situated in scope. That really occurred, background, 1974 when

it was determined that the high-energy line break criteria was such that the main steam and feedwater lines are in what's called our intermediate building. Intermediate building also on another floor had both motor driven aux feed pumps and a turbine driven aux feed water pump. So approximately the 102 line break intermediate building we could not guarantee the operability of those three pumps. So we added, basically, a bunker at our separate standby aux feedwater system completely separate from the main steam and feedwater lines. The penetrations didn't go through the intermediate building. It was all completely separate. We would use that in the event -- at the time it was in the event of a high-energy line break.

CHAIRMAN BONACA: Yes.

MR. WROBEL: Subsequent to that we were able to take credit for the standby aux feedwater system for additional phenomena, for example tornado protection for the original aux feedwater system was not tornado, but the standby system was. And so we didn't have to modify anything.

CHAIRMAN BONACA: Those fuel aux feed lines, they're both steam driven by the pumps?

MR. WROBEL: Motor driven.

CHAIRMAN BONACA: Both?

MR. WROBEL: Both motor driven.

CHAIRMAN BONACA: The design one and the backup?

MR. WROBEL: We have 200 percent turbine driven.

CHAIRMAN BONACA: Okay.

MR. WROBEL: Two separate 100 percent motor driven. And then two 100 percent motor driven backups. We have 600 percent capacity.

CHAIRMAN BONACA: Okay.

MR. WROBEL: And aux feedwater never seems to show up in our risk equation very high because of that.

CHAIRMAN BONACA: No. All right. It wasn't clear in the application. I mean, I'm not saying -- I thought it was a very clear application in general, but I just couldn't understand how many systems you had in the aux system. All right.

MR. WROBEL: Okay.

CHAIRMAN BONACA: Any other changes of substance? I mean, you pointed out the design basis is better than modern one because you went through the SEP. Yes, but your design maybe is not as

robust as, you know, as a plant where you don't have to worry about that wall in between two trains to collapse and take out both.

MR. WROBEL: Right.

CHAIRMAN BONACA: So I just, I was looking for some insights that you may have outside of that specific system I describe. Anything else that --

MR. WROBEL: Most of the changes that we made, we did make some changes for high-energy line breaks with osculated breaks, not just in the intermediate building but wherever there was a high-energy line break and assured ourselves that we would have a system that's available to mitigate that high-energy line break separate from the break itself. And we did have to do a fair amount of separation in that area.

We did some, and for say tornado protection or block wall protection. That was another big issue.

We had to protect individual components, like our main steam isolation valve. Actuators were separated -- were protected, we build enclosures around those that that if a block wall fell them, it would not impact them. So we could do that.

CHAIRMAN BONACA: Now I have a question. So for those components that serve as a backup to makeup for the fact that you could not meet the SLP, okay, like you know the extra auxiliary for those trains.

MR. WROBEL: Right.

CHAIRMAN BONACA: So did you treat them as safety grade systems or are some of them are non-safety grade.

MR. WROBEL: Some are safety grade and some are what we call safety significant or augmented quality.

CHAIRMAN BONACA: Okay. Okay.

MR. WROBEL: If it was done purely for tornado or flood protection, then those components did not necessarily become safety related. They became augmented quality or safety significant. But we did treat them in the scope of license renewal as (a)(2) components.

CHAIRMAN BONACA: Okay. So you did include in the scope?

MR. WROBEL: Yes.

CHAIRMAN BONACA: That was your methodology?

MR. WROBEL: Yes.

CHAIRMAN BONACA: Okay. That's it.

MR. WROBEL: The other thing that we got out of the Systematic Evaluation Program is early use of risk perspective. Just after WASH 1400 was used, it wasn't a global PSA for the plant but on an individualized basis the NRC did use cost benefit analysis to determine whether or not or to what extent we should make some modifications. One of the ones that comes to mind particular containment isolation valves. Our containment isolation valve arrangement is not consistent with the current GDC 53 through 57. And on another defined basis we're able to show that for the most -- except for one case, I believe, all our containment isolation valves or the differences from the GDC did not make them risk significant if we maintained them as it was.

CHAIRMAN BONACA: Okay.

MR. WROBEL: So that was a good insight on risk perspective.

And like I mentioned, we did make some cost beneficial plant changes, primarily the ones that I already talked about.

MR. FORD: Could we go back to the risk perspective aspect? The topic that will come for

conversation is the justification for one time inspections. When you are making those justifications, did the whole question of the risk perspective come in? What if you are wrong? Did you ask the questions what if in terms of the risk perspective?

MR. WROBEL: On the one time inspections, what we did is we tried to pretty much follow the guidance that was in the Generic Aging Lessons Learned. We looked at the types of inspections that we felt there was a material environment combination that could result in potential damage. And so we looked at what type of current procedures we had, our preventive maintenance program, we looked at that. If we didn't have something there and there was like a water chemistry and the only program that we had was water chemistry and there was potential for damage, then we added that into the scope for our one time inspection. And the way that we determined which components to inspect had some risk significance to it.

Now, Gerry, if you want to go into a little more detail as to how we picked the particular one time inspection components, but it

did have elements of risk.

MR. FORD: The reason for my question is, maybe it's out of turn here in the discussion, but much of your justification for some of the one time inspection source, well at such-and-such a date we looked, we saw no problem, therefore essentially we won't again. Now, that's a one time look in a time dependent aging mechanism, which is not necessarily linear with time. So if your rational was wrong, what would the impact be on the safety of your plant? That's why I'm bringing it up under the risk perspective?

MR. WROBEL: All right. Well, that certainly didn't come up in SEP.

MR. FORD: Right.

MR. WROBEL: Not to that level anyway.

I believe that the one time inspections that we committed to do are quite extensive and they're really only in the areas where we thought that the degradation mechanisms were either very slow or nonexistent, but we thought we would look anyway.

A lot of the inspections that we have focused on for the next 33 years, we put them in what we call our PSPM program, periodic surveillance

and preventive maintenance program. So what a lot of people might have put into one time inspections, we thought this is worth repeating. And so we actually have a lot of the inspections that are part of our PSPM program, the ones that we thought are low risk significance, we put in --

MR. FORD: Okay.

MR. WROBEL: The nice thing about being this old, not me but the plant, was that we actually have a lot of operating time on the equipment. So if we do not see anything, we're talking about not seeing anything after 35, 36, almost 40 years of operation. So, you know, the aging would have had a good chance to envision itself, or come about already. So that's how we picked those.

Anybody else wants to pick up more.

MR. ROSEN: Let me ask you a little bit more about the risk perspective. Do you have an internal events PRA?

MR. WROBEL: Yes. Our current PRA includes internal events, external events but not seismic. Fire and shutdown.

MR. ROSEN: It does.

MR. WROBEL: We've a very comprehensive PSA. We've just gone through our peer review and

make a few adjustments, but nothing spectacular. But, yes, it's quite a full PSA.

MR. ROSEN: Good.

MR. LEITCH: Was it this early use of risk perspective that led you to see the need for the installation of the backup aux feed pumps or was that some other kind of regulatory action?

MR. WROBEL: No, that was purely deterministic.

MR. LEITCH: Yes, the SEP?

MR. WROBEL: Yes, it was pre-SEP even. You have a steam line in the same room as your protection system, it didn't seem like a good idea at the time.

MR. LEITCH: Yes. Yes.

CHAIRMAN BONACA: I still am surprised, pleasantly surprised about the capacity of the pumps, that you have two additional 100 percent capacity pumps.

MR. LEITCH: And you have some kind of a wall or a moat or something that divides the circulating water pump house? Was that a result of this perspective?

MR. WROBEL: A flood dam.

MR. LEITCH: Yes, a flood dam. Was that

a result of risk perspective.

MR. WROBEL: No. That was as a result of the condenser failure at Brunswick, I think back in '72.

MR. LEITCH: Yes.

MR. WROBEL: Where we decided that if it could happen there, it could happen to us.

MR. LEITCH: Yes.

MR. WROBEL: So we did an analysis on what would be the result of a condenser failure and we added some flooding failures to the plant as a result of that.

MR. LEITCH: So I guess I'm trying to understand if the early use of risk perspective led you to any physical modifications of the plant back in that time frame?

MR. WROBEL: Yes, it did. It either both led us to some additional modifications. I believe there were some penetrations that had thermal overload that it didn't have, and we checked the risk perspective and put them in there. So there's thermal overload protection, I believe, on two to four containment electrical penetrations that were put in.

There was also, like I said, the risk

perspective showed we'd have to do some modifications, like modify our containment isolation valve arrangement.

MR. LEITCH: Yes.

MR. WROBEL: And these were all early PSA analysis that were done by the staff and reviewed by us. But really it was their call on those.

MR. LEITCH: Yes. So this was mid-'70s time frame?

MR. WROBEL: This was about 1980 by the time we got to that point.

MR. LEITCH: Yes.

MR. WROBEL: It started in '77. By the time we got to the NUREG-0821 it was 1981 or '92.

MR. LEITCH: Yes. Okay. Thank you.

MR. ROSEN: You've done an interesting job talking about the early use of your risk perspectives. Can you update us a little bit about what you're doing with the risk perspectives now? Are you risk, for example, for configuration risk management or --

MR. WROBEL: Yes. We have online risk monitor called EOS at Ginna. And evolutions that are done at Ginna Station are punched into what we

call EOS to determine whether or not the risk profile changes significantly. If we get to a profile level of an orange, what's equivalent to an orange, I'm not sure exactly what level our first step is, but you hit an orange you have to go through PORV review in order to even make the evolution. And you don't make an evolution that goes to red. So that's on a daily basis, any MODs, maintenance get done that way.

MR. ROSEN: So you're using this to comply with 56.65(a)(4)?

MR. WILSON: Partly, yes. It is part of the stuff we use for 84, but it goes beyond what 84 requirements are.

CHAIRMAN BONACA: You need to come up to the microphone. Thank you. And speak with sufficient clarity and volume.

MR. WILSON: David Wilson, RG&E.

The risk monitor and EOS is used for maintenance rule determinations, but it's also used in addition to that for normal ways of doing business just to make sure that even though it's not a maintenance activity, that we're not putting ourselves in an unsafe configuration.

CHAIRMAN BONACA: So it's capable of

quantifying multiple components out of service?

MR. WILSON: That is correct.

MR. ROSEN: So would you characterize your current risk, use of risk tools as aggressive or part of a--

MR. WROBEL: I would say fairly aggressive. I don't know what else we would use it for. I guess day-to-day operation --

MR. ROSEN: Risk-informed in-service inspection?

MR. WROBEL: We have not done risk-informed in-service inspection yet. However, we have used it in quantification designs or in evaluating modifications.

We have looked at a risk-informed ISI at one point, have not done it. Probably looking at it again now that we have, hopefully, another 20 years of capable operation.

I think Gerry Geiken wants to say something.

MR. GEIKEN: I'm Gerry Geiken with Ginna Station.

We have looked at the cost benefit analysis of going to risk-informed inspections. And at the present time have concluded that there isn't

sufficient savings economically to justify the analysis that would be required to going to risk-informed inspections. As a result, we continue to do ISI as under the current requirements of ASME Section XI.

MR. WROBEL: This is going to go quite a bit faster, I believe, because we have covered quite a few of these already.

Again, we're the oldest operating PWR. We talked about the standby auxiliary feedwater system as a unique feature.

We do have -- this is actually fairly comparable to what you heard at Robinson last month. We do have grouted containment tendons, but we have rock anchors that are grouted right into the -- so the tendons go right into the ground block. And we have the rock anchors and tension bars that are at the base of our containment.

I don't know if this is a good time to talk about it, but also have station blackout recovery. We do have a sketch. I think that's next. I don't know if you want to ask questions about the level of --

CHAIRMAN BONACA: You have an open item, is that correct?

MR. ROSEN: We do want to hear about that.

CHAIRMAN BONACA: Yes, when we get there.

MR. WROBEL: Okay. We can wait on that. The sketch is next. We'll go back to that sketch when we get to station blackout recovery.

MR. ROSEN: It's apparently a phenomenon that happens in upstate New York.

MR. WROBEL: Yes.

MR. ROSEN: Were you affected by it? Were you one of the sections of the trip, by the way?

MR. WROBEL: Yes. We did get an automatic trip, but we didn't have a station blackout. Our diesels worked fine.

MR. ROSEN: You have two of them, right?

MR. WROBEL: Yes.

MR. ROSEN: They both started and ran and loaded?

MR. WROBEL: Yes. So we didn't get a station blackout.

MR. ROSEN: No. No blackout.

MR. WROBEL: We just have snow.

I just wanted to let you know, our

performance indicators are green, inspections findings are all green so I didn't put a slide on that. But I think the NRC has one. It looks kind of a like a metal --

CHAIRMAN BONACA: Yes.

MR. WROBEL: Skip this until we get to station blackout.

We're going to talk a little bit about what currently is happening at Ginna Station or has just happened.

We just changed our reactor vessel head. It's a one piece construction. And we put in new controller rod mechanisms. We have the old ones as spares. We did put those in while we were at it.

I'll go to the next slide just to show a couple pictures of it. That's the head in the shot. The next one is with the ventilation installed. And we have 400 more slides of that, but we won't show you those today.

MR. ROSEN: Do you have an access patch big enough to get --

MR. WROBEL: Yes, and it was really a good picture. Should have brought that one in. As it was going through the equipment hatch, did not have to modify it as opposed to when we did steam

generators and had to cut a hole in top of the containment.

MR. ROSEN: Pardon me. I didn't understand what you said.

MR. WROBEL: Oh, as opposed to when we replaced steam generators, we had to cut holes on top of containment. This came in through the equipment hatch.

CHAIRMAN BONACA: Now you use 690 TT if I remember, correct?

MR. WROBEL: Yes.

CHAIRMAN BONACA: And CRDM, I mean are they now differently than in the design that we had on the 600, or is there a different --

MR. WROBEL: No, I believe they're the same. Gerry, are they any different than -- I mean, they 304 stainless steel, but I don't think the designs any different than we had before.

CHAIRMAN BONACA: Because the weld material is different, if I remember, too.

MR. GEIKEN: Yes. This is Gerry Geiken.

The weld material is Inconel 52.

CHAIRMAN BONACA: Right.

MR. GEIKEN: Joining the penetration to the head. It's all I-52. Bare wire cake.

CHAIRMAN BONACA: Okay.

MR. WROBEL: In addition to replacing the upper reactor vessel, we did a detailed lower reactor vessel head inspection. We took off the insulation off the bottom or lowered the insulation so we could look at it. We did detailed visual, VT-1 examinations at all 36 nozzles. And there were no indications of any boric acid.

MR. ROSEN: Taking the insulation off, was it designed to have come off or --

MR. WROBEL: No. No. We had to take it off. And we have a new system put in now that makes access easier. There's room where you can put a snake through a camera for future inspections. So we've redesigned the bottom of head insulation.

MR. FORD: I'm assuming that with the lower T, that temperature, that you are a low susceptibility plant, is that correct?

MR. WROBEL: That's correct. For the bottom, and as well as the top.

MR. FORD: The top?

MR. WROBEL: Because of the material differences also.

MR. FORD: But even without the change of material, it would still be a low susceptibility

plant, is that right?

MR. WROBEL: Bottom or top?

MR. FORD: The top?

MR. WROBEL: I think we would be medium.

MR. GEIKEN: George, it would have been medium.

MR. FORD: So you changed it purely just for insurance purposes, technical insurance?

MR. WROBEL: We did an economic analysis of how much it would take to -- every outage gear for it just in cases and it was economically viable to replace it other than do that every year. And we will still being inspections, but on less frequent basis.

CHAIRMAN BONACA: Yes. So now the head has been replaced and the plant is running now?

MR. WROBEL: Yes. Yes, it went quite smoothly.

MR. MECREDY: This is Bob Mecredy.

On the reactor vessel head replacement, there were really two pieces. One was the economics in looking at the costs of inspections between 2003 and the end of the current license, 2009.

The other piece is intangible, which is with replacing the head we're in control of our

destiny. With overhead and inspection techniques, one could envision going in and looking at the CRDM, identifying things that might be real, might not be, might be an artifice of the examination techniques and the impacts on outages. So, it really made sense from several standpoints to replace the head. And so we made that decision early on to do that.

MR. FORD: You're one of the stations, few stations that have come in front of us, who have actually gone through this head replacement. Just for our interest, what sort of quality control was applied for welding Alloy 52? Do you know that answer offhand

MR. MECREDY: I don't, but Gerry Geiken.

MR. GEIKEN: Yes. This is Gerry Geiken.

The head was fabricated at Babock & Wilcox in Cambridge, Ontario.

MR. FORD: Okay.

MR. GEIKEN: Their own internal quality organization is very good. And we augmented that by multiple visits to the plant. We had our own NDE people providing some oversight to various critical activities. And we had a constant presence of our welding engineer during the entire fabrication process. So I would say we didn't necessarily rely

on the quality control measures that they could or would apply and use, but we tried to exercise some of our oversight. And I think the overall quality of the fabrication is excellent.

MR. FORD: True.

MR. MECREDY: The other advantage we had was with purchasing new control rod drive mechanisms. We were able to get those on site prior to the outage and complete the welding of those onto the new head outside, you know prior to the outage. So we had the advantage of more accessible environment and really a better environment for people working on it, inspections oversight. And so that was done. And, of course, it was facilitated by the size of our head, being able to go in through the equipment hatch.

MR. WROBEL: The other major issue that we looked at was on the lower reactor vessel head inspection. This detail of the penetration, as you can see, the paint and weld pad, everything was in excellent condition. There was no leakage, no indication of leakage through the nozzles, boric acid and, again, it came out as good as we would expected on the bottom head.

MR. ROSEN: You know, that's not the

dialogue I would have given, given this picture. I would have said there was some indication or leakage from it. Or what am I looking at when I look right on top of that nozzle?

MR. GEIKEN: I think it's the paint.

MR. WROBEL: Right there?

MR. ROSEN: Go a little to your left. Put the dot back on. Yes, what's that stain there?

MR. WROBEL: Paint.

MR. ROSEN: And that's paint also above that? There's no --

MR. GEIKEN: It's zinc-rich paint. It's painted with a zinc-rich Carbozinc-11. They got a little sloppy and they got some of it onto the penetration.

MR. ROSEN: Okay.

MR. WROBEL: We'll have a better picture for the next presentation.

MR. FORD: Given the observations at South Texas, you could be awkwardly minded, if you like, and say here you just painted over the annulus with paint and there's boric acid on top of that. Is that a reasonable question?

MR. WROBEL: That would not be allowed. No.

MR. FORD: You mean it wouldn't be allowed to have occurred or not a good --

MR. WROBEL: You can't cover up something like that. Now if we found any -- we looked real well for boric acid there, because we knew what happened out at South Texas. So we really wanted to know if there was anything. We were prepared to make repairs, if necessary. But we didn't find anything to make repairs to.

I'm not sure exactly the frequency at which we'll be inspecting these in the future. I think it's very outage.

MR. GEIKEN: Every outage.

MR. WROBEL: We'll be looking. So next year's picture is really going to look good.

CHAIRMAN BONACA: Okay.

MR. WROBEL: The other issue that is a more recent issue that came up is in our containment sump, what we call our B sump. That's a depiction of what it looks like. The sump is -- a wire mesh screen. And the RHR entrance with a bell mouth entrance piping at the bottom. And we did do an inspection of that this outage, and we did find things. We did find some minor bypass flow issues. We did find some openings that were greater than the

size of the mesh, the 3/16" by 9/16'.

Foreign materials we found dried boric acid in the bottom of the sump where there had been leakage in the past and then just evaporated. And that was not of any safety significance.

We did find some metal parts in there, clamps a file. And less than 6 ounces of some other foreign material.

So there was some foreign material in the bottom of the sump. We had a detailed NRC inspection that concluded last week. Preliminary findings are that we had 2 non-cited green violations of our corrective action program as a result of that inspection.

MR. ROSEN: Because of the materials found in the sump or --

MR. WROBEL: One was materials found in the sump and one was the bypass flow. If you want to point to the next picture. That's the mesh size that it was supposed to be.

MR. ROSEN: Yes.

MR. WROBEL: That's an opening that clearly is larger than that. That's inside the sump underneath the floor.

So, next picture is our repair as well

as the plates over that. So there are no more openings greater than that mesh size. So you can see that less than a day later that was done. So there were several openings like that that were found.

The NRC, at least preliminary indication from the inspection, was that they were very low safety significance, but we did get two non-cited green violations. Preliminary.

MR. LEITCH: Absent that bypassing, can you make any comment on the adequacy of the screens that do exist? In other words, have you revised your operating procedures or is there ongoing analysis to confirm that?

MR. WROBEL: Yes, we did a detailed analysis in accordance with, I believe, it's Reg Guide 182, Rev 2 or 3 when we did a steam generator replacement in 1996. We did a transport analysis with the current state of the art then, which I think still is pretty close to what we are now given that it's still evolving. And we did analysis of the screen as it was supposed to be, and it did indicate that there would be some head loss. I think we modified the bottom of the fibrous insulation from reflective metal insulation to a type of more

fibrous insulation that insulated better. We did put catchers up by the steam generator so that it wouldn't get into the sump, but then we also did an analysis of what the transport analysis would be to the sump, how much head loss there would be, did all the NPSH calculations for our HR. And, obviously, we found that there is margin there.

The latest analysis was did was in '96, to my recollection, unless somebody can remember.

MR. ROSEN: That's a curious discussion, George. You say you went from reflective metal insulation to a more fibrous insulation?

MR. WROBEL: In that one, in the bottom of the steam generators. There's more efficiency. That reflective metal was just allowing too much heat out. But we did compensate for that by putting a fibrous debris screen right underneath the steam generators, right in that vicinity. So we didn't just willy-nilly change it. We thought about it, changed it out with a better insulating properties, but we didn't compensate for it by putting the screens down underneath the generators.

MR. LEITCH: Well, I guess my question, it seems to me that there's some kind of an NRC correspondence to all PWR licensees. I don't know if

it's a generic letter or just what the document is, that requires a response. And I guess what I'm saying is have you responded to that, and if so, how did you respond.

MR. WILSON: This is David Wilson, RG&E.

MR. WROBEL: The responder will respond.

MR. WILSON: In fact, these inspections that identify the bypass flows were done in accordance to our response. The Bulletin 2003-01 requires to look at certain attributes and try and determine what we could do right now to reduce the risk consequences of screen fouling. And there were several things that we committed to doing, including these inspections that we are in fact doing right now. They're not all required to be done at this instant.

One of the Bulletin key items was to modify your operating procedure such that perhaps you would refill your RWIC or add more water volume to containment. Within our current licensing basis and accident analysis that would be something that would not be allowed under 50.59. In fact, may have more detrimental effects than positive effects.

But what we committed to in that Bulletin response, and what we are doing, is working

with the industry, with particularly the Westinghouse Owners Group in order to analyze and evaluate the consequences and possibilities of adding more water or reducing ECCS flow, or securing a train of spray if you didn't reach a certain volume in order to delay the injection times to minimize the sump volume and increase the transport times.

All that being said, the jury's still out from an analysis standpoint. We're participating. And we committed to in our Bulletin response was that we would follow through. And once the science is done, we would evaluate whether or not we can actually execute those changes. Because just because it comes out of a Westinghouse Owners Group or some generic emergency response guidelines does not necessarily mean it's still appropriate for your facility. You still have to do individual.

The other things that we looked at were debris in containment. Not just how to filter the debris out, but what the debris source terms.

We took detailed high resolution videos and walk downs and measurements of the insulation sources for the loop areas and for those connections.

We don't know necessarily what the generic letter that's going to come out will look like with respect to what we have to protect against. There's issues right now with water chemistry. There's issues with flocculents and things like that.

So our thrust this outage was to reduce the risk. And the things we could do to reduce the risk that were most appropriate were evaluate and then, unfortunately in our case, repair our screens to be consistent with our design basis and to remove debris.

And the debris sources that we found that were removable, we found paper tags. We made significant and major modifications to our procedures for closing out containment and for modifying our debris control as we escalated the modes from a refueling mode up towards power operation.

And beyond that, you know, it's business as usual. We've got the commitment letters in and we're following through on them.

CHAIRMAN BONACA: What's the volume of your RWST?

MR. WILSON: About 300,000 gallons.

MR. WROBEL: We might as well talk a little bit about the license renewal application now, since we're mostly done with the presentation.

The preparation, we did not have too many contractors. We primarily did the application in-house. We have matrixed staff, everybody participated in here except me. Because I worked part time on license renewal and part time on other jobs, like looking through sumps.

We did use specialty contractors where we needed to. We had several areas that we didn't have the expertise in-house to do the work, so we had Framatome, for example, do some analyses. Westinghouse did analyses. And we did not a fatigue monitoring program, and we had a contractor come in and install, initiate a fatigue monitoring program for us which turned out to have great results.

So, we do 95-10, Standard Replant format. We were the third plant to do that. And, of course, all three plants came pretty closely after each other, so there was not much opportunity for lessons learned. But we did use the Standard Replant format.

One of the bigger portions of our application, as you might have seen, is the GALL

3.x-2 tables. Those are tables that are material/environment combinations, programs that are not consistent with the GALL. For the most part, or almost completely, they were additional material/environment combinations that were not in the GALL, possibly due to the fact that the lessons learned were from problems and if there were material/environment combinations that had no problems, then they wouldn't be in the GALL. So we ended up putting them in a 3.x-2 table. And that added many pages to our application.

Also, the use of systems. When we had a material/environment combination in one pipe system and it wasn't in the GALL, then we put it in a 3.x-2 table, even though we could have gone to another system, FECCS system or something, but we found it in the CBCS, so that's why we put it in that format.

We did all the interim staff guidance that were available at the time. We addressed those in the application. And all the interim staff guidance documents that were out.

Subsequent to that we appear to have answered to in RAI space, so I believe we're up to date on all of our interim staff guidance documents.

We do have some scoping open items, but

we'll be talking about that when the NRC makes their presentation.

MR. LEITCH: Without getting into the details of those open items, I guess I had the impression that a number of these open items had somewhat more substance and still somewhat more areas of disagreement than we normally see at this stage in the process.

I mean, frequently at this stage the staff comes and tells us well there's so many open items, but they're all basically resolved. We're awaiting formal documentation of the resolution and so forth. It seems like some of these, although there are only eight, but I think there are about 5 or 6 that seem to me to represent some significant areas of disagreement. Is that a correct perception?

MR. WROBEL: I think when we go through that we'll find that we're significantly reduced from 8 to possibly 1 by now.

MR. LEITCH: Okay.

MR. WROBEL: But let me go over them when Russ goes through them.

MR. LEITCH: Okay. Fine. Yes, that's good.

MR. WROBEL: We'll be available for comment also.

MR. LEITCH: Yes.

MR. WROBEL: In case you want to ask us what we think of them.

Selected TLAAs. I just wanted to provide a few of them that I thought were more interesting. If you have any questions on the rest of them, that's fine.

Pressurized thermal shock, we thought that would be an important issue. We did analyze the Ginna reactive vessel with outline materials, both the plate and the weld out to the end of the extended period of operation. You can see that the RT_{PTS} value where the beltline is 270.6, which is significantly below 300. We've done the analysis out to 80 years, and still quite a bit below 300 degrees. And the plates, you can see there's a lot of margin over there.

This is one of the open items that staff is independently reviewing. I think they'll be done relatively soon and, hopefully, agree with us.

MR. ROSEN: To what do you attribute all that margin, given this is an old plant and the technology for building vessels was somewhat less

mature at the time?

MR. WROBEL: Yes. I think we got a really good vessel from B&W. It was all fabricated at the -- where was? Mount Vernon, Indiana facility. It wasn't moved around. A lot of the B&W vessels back then were moved from one place to another.

And I think the cooper and nickel content that we had is relatively low, .25 and .36 percent. So we were able to -- so those values indicated relatively low -- fluence isn't particularly high either, so that helps us out.

MR. ROSEN: And why is the fluence low?

MR. WROBEL: We went to a low leakage back in the mid-'80s, I believe. And we've maintained that since that time.

We did the analysis out to, I believe, 54 EFPY just in case there might be an upgrade. Certainly 80 percent used to be the standard capacity factor, but it certainly isn't anymore. More like 95 percent now. So rather than 48, we went out to 54 EFPY with these analyses. And so it seems to be holding true.

MR. ROSEN: So 54 would represent a 90 percent capacity factor averaged over the life of

the vessel?

MR. HERRICK: That's correct. Now, say, if we do an upgrade, that will bump that up a little bit. So then it might be 85 percent with an upgrade or something. And, obviously, if we have to redo the calculation with a higher fluence rate, then we'll do that also. But it looks like we have significant amount of margin.

Also it helped that we had credible surveillance data. If we had used simply the Reg Guide 199 Revision 1.1, the generic data, I think that our PBS value is about 290. But having credible surveillance data got it 270.

CHAIRMAN BONACA: You have an open item on the specimen, right?

MR. HERRICK: That's right. But it's not related to the analysis, it's related to when we test it.

CHAIRMAN BONACA: Right.

MR. HERRICK: We'll go over that later.

MR. WROBEL: Factor toughness of the reactor vessel, we have taken four capsules out, we have two left to go. Some of the capsule Charpy V-notch data would indicate that our upper shelf energy was approaching or could be below 50 foot

pounds. So rather than the next time we do the test to find out that maybe it actually is below 50, we decided we would contract with the reactive vessel manufacturer and do a fracture mechanics, a detailed fracture mechanics evaluation called equivalent margins analysis, which is an alternative to the code analysis for upper shelf energy. We had that performed for this reactor vessel for license renewal out to 54 EFPY. And there's significant margin under Section XI Appendix K. If you want more details on that, Gerry will answer them. But there is significant margin in the fracture toughness of the reactor vessel from an upper shelf energy standpoint.

CHAIRMAN BONACA: Okay.

MR. WROBEL: But we did use that, but equivalent margins analysis.

MR. FORD: And that question will also be covered later and the whole question of us of the specimens.

MR. WROBEL: Yes.

MR. GEIKEN: George, you ought to pull out that we don't know that the upper shelf energy is below 50.

MR. WROBEL: Yes.

MR. GEIKEN: The last capsule we tested, the Chaprys came in at 55. And they seemed to plateau out at 55. The last three capsules, the upper shelf energy was nearly the same balance between 52 and 55.

MR. WROBEL: Right. Yes. So we don't know if it'll be below 50, but we did the analysis just in case.

MR. FORD: But it's fair to say that these are two open items which have not been secured?

MR. WROBEL: As far as I know, this one is closed. There's nothing open on this one.

MR. ARRIGHI: I'm sorry, which open item was it?

MR. WROBEL: Fracture toughness equivalent margins analysis. Hopefully, that's an open item.

MR. ARRIGHI: When I get there, we'll address it.

MR. WROBEL: Gerry said it's not.

MR. GEIKEN: No, shelf energy is closed.

MR. WROBEL: The other major TLAA that we did is we did the T calculations for all of the RCS and put the details. We did do these

calculation in accordance with the ISG. At 15, it talks about the environmental effects. We did use 15.35 for stainless steel and 2.53 for carbon steel. We did these for 60 years, and you can see that all the values are quite a bit below 1.0, even for 60 years including maximum environmental effects. So we did surge line, nozzle, charging nozzle; we did all those detailed analyses because of the fatigue monitoring program that we had installed. And did all the calculations.

So there's no open items on fatigue of the RCS.

In terms of programs, we have 33 aging management programs that we took credit for; 20 of them were consistent with the GALL. I'm sure we'll hear more about that.

Twenty were consistent with the GALL. Ten were consistent with exceptions. Of those 10, probably 5 or 6 the exceptions were quite minor. They were possibly a different addition of a reference, but there were no major exceptions taken through the vast majority of the programs that took exception to the GALL.

All the exceptions were discussed with the NRC staff. We have plant specific operating

experience and results, and I don't believe there's any open items left on programs that are consistent with GALL. They've been reviewed several times and all the differences are justified.

We did have 3 plant specific programs that were not GALL programs, mentioned earlier. The periodic surveillance maintenance program, thimble tube inspection program and systems monitoring program. Those are programs we already had in place. They weren't in the GALL, but we do take credit for those for aging management so we described those in our application.

The vast majority of programs we already had. We either made minor enhancements to them; 6 programs that we enhanced. A lot of it was like the boric acid corrosion program, which we had a boric acid corrosion program but it didn't extend to the same level that the current guidance would have you go to. So we added not just reactive cooling system in the vicinity of coolant leaks, but anything -- but any carbon steel that could get leaked on by boric acid, whether it's in the CVCS line, whether it's electrical conduit, whatever it is that could leak onto boric -- boric acid could leak onto carbon steel is covered on our current boric acid program.

MR. ROSEN: Does it include, for instance, the pressurizer nozzles? Pressurizer heater?

MR. WROBEL: Yes. Yes. I mean, if it can leak from there, then it's covered.

MR. ROSEN: And you looked at the pressurizer heater, the bottom of the pressurizer?

MR. WROBEL: I don't know if we've looked at -- did we look at that?

MR. GEIKEN: Yes, we looked on this outage. We took the insulation off.

MR. ROSEN: Pardon me? Again?

MR. GEIKEN: Sorry. I'm Gerry Geiken.

We did ISI examinations this outage on the pressurizer surge nozzle.

MR. WROBEL: Oh, that's right.

MR. GEIKEN: And we uncovered the bottom head, a significant portion of it.

MR. ROSEN: You covered the bottom head, is that what you said?

MR. GEIKEN: We uncovered.

MR. ROSEN: Okay. And you looked at the bottom head, you looked at the pressurizer heater?

MR. GEIKEN: We looked at -- yes. The bottom head is where the pressurizer heaters

penetrate. And we looked all around there. Yes.

We don't have any Inconel 82/182 welds in our pressurizer. So if the issue is primary water stress corrosion cracking, which I suspect you're thinking of, what you may be thinking of, we don't have that. All our pressurizer penetrations are stainless steel, welded with stainless steel weld metal.

MR. WROBEL: We did generate four new programs that we didn't have before. We have a fatigue monitoring program, cable condition monitoring program.

We did make a commitment to look at reactor vessel internals in the future and to try to look at finer cracks than we have currently expertise to do that. And we're committed to do that by 2009 or have a program sent in, I believe, by 2007 and approved by the NRC. We don't feel that that's going to be a major issue.

Reactive vessel head penetration, we were looking and we now have a formal program. It was committed to more from the current Bulletins than from license renewal, but the two intersected and we took credit for those.

MR. LEITCH: I have a numbers question,

I guess. I am not sure if this should go to the licensee or the staff. But in an inspection report the staff said they looked at 28 programs of 33 that the licensee claimed were consistent with GALL.

MR. ARRIGHI: Yes. This is Russ Arrighi.

During our aging management program audit we did look at 28 of the 33. For those other 2 programs there were some differences. And in the application the licensee had the ten attributes for that program. And that was reviewed in-house by the staff.

MR. LEITCH: Yes.

MR. ARRIGHI: So when we said we reviewed those 28, Mr. Wrobel is correct, there were only 3 that are plant specific, but the wording on that may have been misleading in the report. Again, any attribute that was different than GALL was reviewed in headquarters by the staff.

MR. LEITCH: Now, I'm still not sure I understand. I guess my question is going into this inspection we thought that 28 programs were consistent with GALL and coming out of the inspection we found that there were only 20 consistent with GALL. Is that correct or am I

missing the point here?

MR. ARRIGHI: When I put the report together, looking at the spent fuel pool neutron absorber program, Ginna's program, it covers the ten attributes but it doesn't match the attributes explicitly. So when I was reviewing it, I didn't consider that a GALL program when actually, already when I sit back and reevaluate it and talking with George, you know, for consistency I should probably should have put that that program is a GALL program and even though they have the 10 attributes discussed in the application, I should have said that it wasn't a plant specific program, it was a GALL program. However, that program was viewed by the staff, because again the attributes were included in the application. And in the in-house the NRC staff could review that here because the applicant, again, the information regarding the attributes in the license renewal application. And that's the same for the other programs also.

MR. LEITCH: Okay.

MR. FORD: I have a more technical question. I must admit, reading through the application and the SCR I was a good deal frustrated by the lack of detail, factual detail.

For instance, in your fuel oil chemistry, the AMP, you are not going to put any biocide or corrosion inhibitors to protect the internals of that tank. No justification is given it, apart from the fact that you haven't seen MIC or any other corrosion event there.

There are a few questions asked by the staff regarding to your thimble tube AMP. And all the aspects of the justifications for the one time inspection. And, unfortunately, in both the SER and the application the justifications for the actions that are going to be taken, are supposed to be taken are all verbal. There is no data to support your assertions.

Can you give us a feeling as to the extent of the actual engineering data driven discussions that went on between your organization and the NRC to back up those?

MR. WROBEL: Yes. The actual data --

MR. FORD: Were the graphs people were looking at, or the data meet your justifications?

MR. WROBEL: I think a lot of it was operating experience. We did rely heavily on operating experience. Some of it we did rely on science.

A lot of the information that was actually useful in documentation is in what we call our program basis documents. Program basis documents are where were we implement all the programs. Those were available to the staff for detailed review, but they did not go into the application. They're all about 30 pages long, have all the procedures that implement the programs and a lot more of the operating experience and history.

MR. FORD: So they did do more than Appendix B, the AMPs?

MR. WROBEL: Oh, my goodness, yes. I mean, everyone of those programs has a 30 pages program basis document behind it.

MR. FORD: And there's data, extrapolations of data?

MR. WROBEL: Yes.

MR. FORD: Uncertainties, all of these are what happens if?

MR. ELLIOT: Barry Elliot.

I thought restricted at thimble 2?

MR. WROBEL: Yes.

MR. ELLIOT: They had done a whole lot of inspections of the thimble 2 for wear. And they have data from the early '90s on. And they based

their inspections based on that actual data from inspections on the thimble 2. So they actually have data there from their previous inspections, which they base their inspection program for the thimble 2. So the guide tube, that was an issue that we brought up that they had originally had a mitigation program, but no monitoring program. And we've discussed that with them with great detail, and you can see in our SER. And it's still open, but they have proposed a monitoring program now.

MR. FORD: Okay.

CHAIRMAN BONACA: I had some similar questions, because for example I ask them now. Above ground carbon steel tanks says that you will perform a one time inspection on the reactor makeup water tank. It doesn't say what inspection you're going to perform. I would like to know is it automatic inspection, visual?

MR. WROBEL: Gerry's got the details on that.

MR. GEIKEN: This is Gerry Geiken. I can offer the details on that.

We've already done that inspection. We drained the tank completely. Did a 100 percent visual inspection of the painted interior of the

vessel and an ultrasonic examination of the bottom, flat bottom of the tank.

CHAIRMAN BONACA: Okay. And you found?

MR. GEIKEN: We found no evidence of degradation whatsoever.

CHAIRMAN BONACA: Okay. All right.

MR. FORD: I can understand your rational. Let me give you a hypothesis and then you shoot it down.

You find no corrosion in your fuel tanks, presumably because your fuel supplier has met certain specification limits. Assume that you get a bad lot and you get an attack of bacterial-assisted corrosion, induced corrosion, that can go extremely fast locally.

Now the way you've justified the one time inspection, which I believe is what the fuel oil tank you've got because you haven't seen any corrosion, what happens if next year you get this rapid corrosion? You've got no process apart from I understand it a ten year inspection periodicity for that tank. You're not going to catch that.

And then the follow question is what the consequences?

MR. GEIKEN: Well, actually our diesel

fuel oil, every batch is tested by various ASTM methods.

MR. FORD: Okay.

MR. GEIKEN: As in accordance with the requirements of the GALL program.

MR. FORD: Yes.

MR. GEIKEN: Prior to being delivered to the site and prior to being dumped into the tanks, or prior to the tanks being filled.

In addition, I think our frequencies now for internal inspections.

MR. WROBEL: Nine years.

MR. GEIKEN: They're still every 9 years.

We just went into them this outage and they're pristine. But in terms of the potential for getting a bad batch, we're as proactive as we feel we can be in terms of inspecting every load of fuel oil. And we do multiple inspections. We inspect not only before the tanks are filled, but after they're filled from three locations. We follow all the guidance that's in the GALL, and I think we've committed to some additional particulate testing.

But your concern is biocides?

MR. FORD: Well, biocides, corrosion

inhibitors. I'm just bringing up those as for instances.

My concern is that not just your stations, all the previous stations we've had exactly the same discussion about what is your justification for a one time inspection for a possibly nonmelior degradation mechanism. So you find no corrosion of degradation today? And that's 20 years into the process. But what's to say that you're not going to have a MIC problem or pitting problem because you don't have inhibitors or don't have biocides in next year?

MR. GEIKEN: Well, actually --

MR. FORD: And you haven't done your consequence analysis, but that's what you told me in the very beginning.

MR. GEIKEN: Actually, the diesel fuel oil testing program and the internal inspections of the diesel fuel oil tanks, they're not one time. I mean, they're periodic.

MR. FORD: Okay.

MR. GEIKEN: So we've been into the diesel fuel oil tanks once every outage, up to 1990 -- what was it, George?

MR. WROBEL: '92.

MR. GEIKEN: '92. So for 20 some years we had a history of data there that showed that there was no internal degradation of the vessels. And we've done the first 9 year inspection since then this outage, and found the same thing.

MR. FORD: I guess I'm excessively susceptible to this having worked in this industry in the cracking side. And you can bet your bottom dollar, tomorrow figuratively speaking you're going to have an "oh, heck" hitting you, which you never realized you were going to happen, because you've had a good 20 years experience beforehand. That's what I'm pushing to.

CHAIRMAN BONACA: Just operating experience is not, by itself, a good --

MR. FORD: A good measure necessarily.

CHAIRMAN BONACA: Necessarily a good project for the next 20 years when you get from 40 to 60. And, of course, it's unchartered territory. I mean, nobody's gone that far.

On the other hand, I think that some of the issues for the tank, you would measure leakage from it before you get to the point where you have no sufficient inventory, I would suspect. I mean, and I will expect that you would have a corrective

action program taking -- because, I mean, you have spec restrictions of those tanks. And you have the fuel levels that you have maintain, right?

MR. WROBEL: Right.

CHAIRMAN BONACA: And so you would have to have -- I mean, if you get below a certain level and you cannot maintain it, you have to shutdown the plant and fix it.

MR. ROSEN: Well, it's also true I think, Mario, that you wouldn't expect to have both tanks leak at the same time.

CHAIRMAN BONACA: Absolutely. So you have a number of --

MR. FORD: Okay, guys. But you're making the answer for them, and I asked them have you a done a consequences?

CHAIRMAN BONACA: No, no. I think there are issues where this is very significant because you have much less margin. Here is an example where you do have more margin than most cases, because you have two and you do have probably small leakage in the beginning. If that is to happen, you probably can monitor it.

But I agree with you, the issue in general, it's a significant issue for the whole

industry, making these projections based on past experience.

I had some other questions here. One I would like to ask is about your neutron noise monitoring system. Now, that's a system that is in place to detect and monitor significant loss of axial preload and core support barrel -- we just heard from another applicant for license renewal, that program was very significant on their site to identify in time thermal shield problems. They fixed those problems. And they're using it to prevent further problems to develop.

I see that you're not including this program in your license renewal or crediting the program for it?

MR. WROBEL: No, we did not credit that program for license renewal the way we do our 10 year ISI and our internals. We haven't really had any comparable issues --

CHAIRMAN BONACA: But you still have this program implemented on site?

MR. WROBEL: I don't believe there is a program on site.

CHAIRMAN BONACA: Well, it's called neutron noise monitoring.

MR. WROBEL: Neutron noise monitoring. No, we don't.

CHAIRMAN BONACA: D2-120.

MR. WROBEL: Yes, we don't have that. I think the application should have said that that's the name of the program but we don't have it and we don't credit it.

MR. ARRIGHI: This is Russ Arrighi the program manager.

In Ginna's application I think every GALL program, I think the applicant had a bullet that there is such a program. But in Ginna's case, even though they mention the program, they said it's not utilized at Ginna. So it's essentially a place holder.

CHAIRMAN BONACA: Okay. So you do not have it at all. I misunderstood.

MR. WROBEL: Sorry.

CHAIRMAN BONACA: I thought that still you had the program and I just -- all right. So you do not have that program?

MR. WROBEL: We don't have a program like that.

CHAIRMAN BONACA: Okay. And you do have a thermal shield?

MR. WROBEL: Yes, and it's in scope.

CHAIRMAN BONACA: Okay. Yes, I imagine so.

Several more questions I wanted to ask at this stage.

Okay. A couple of questions for my consultant that performed the review here and sent some comments out. One is relating to the special blackout and the confidence that we have that based on the experience -- I think we'll hear from that from the staff.

Fire protection. We noted that you do not include jockey pumps, for example, in scope.

MR. WROBEL: That's correct. That's one of the open items.

CHAIRMAN BONACA: That's right. And I just am trying to understand the logic. If I understand it, NFPA requires that you have jockey pumps. They maintain pressure, doesn't it?

MR. WROBEL: It recommends that you have them, it doesn't require it. We have a large pressure maintenance tank that we feel is enough -- has enough of a size that we don't need really need the jockey pumps to maintain pressure. And, again, the intended function is for the pumps to operate

just fine without a jockey pump.

CHAIRMAN BONACA: But essentially the function of jockey pumps was the one of maintaining pressure maintenance function.

MR. WILSON: This is Dave Wilson, Rochester Gas & Electric.

Our configuration at Ginna Station, although includes a pump that could be considered as a jockey pump. It's actually a key filled pump for this tank. And the way the system is configured I think is unique in that the staff hasn't recognized, necessarily, how the physically plant is laid out.

What we have is a 15,000 gallon over pressure tank on the discharge of the pumps.

CHAIRMAN BONACA: Okay.

MR. WILSON: And that tank maintains 10,000 gallons of water which makes up for system leakage, or whatnot. The tank has a couple of ways of being refilled. One is this, what we call a booster pump which the staff calls a jockey pump. So if the tank gets a low level, it can be through that.

CHAIRMAN BONACA: Yes.

MR. WILSON: The other method is when we run our fire pumps for maintenance, particularly the

motor driven fire pump, we can refill the tank during that running evolution.

And so the position that the staff has taken is because we have something called a jockey pump, and we're reviewed against Branc Technical Position 951, which is the early fire protection requirements, they've said that because Branch Technical Position 951 endorses NFPA 20, then therefore we must endorse NFPA 20 even those configuration is not an NFPA 20 configuration.

So that the argument there is not that we need a pressure maintenance source. It's whether or not this key filled pump is in fact a jockey pump required by NFPA 20 --

CHAIRMAN BONACA: I understand now. But it's still an open issue?

MR. WILSON: It's still an open issue.

MR. HERRICK: We'll go into that.

MR. ARRIGHI: Yes, we'll discuss it.

CHAIRMAN BONACA: Okay. Okay.

MR. LEITCH: While you're on the protection of fire protection -- go ahead, Mario, you finish.

CHAIRMAN BONACA: No, no. You go ahead.

MR. LEITCH: I guess I had a couple of

questions about fire protection that related to the inspection of June 23 through 26th. Is the staff going to cover that? There were a couple of issues with respect to frequency of Halon testing, frequency of fire door inspections, frequency of hydrant inspections?

MR. ARRIGHI: Yes. This is Arrighi, the program manager --

MR. LEITCH: There seem to be a lot of lacking areas there in the fire protection.

MR. ARRIGHI: Yes, we have a slide on that. If you want, I'll discuss it now or later.

MR. LEITCH: No, we can wait until that part of the presentation.

Excuse me, Mario.

CHAIRMAN BONACA: Oh, no. No problem.

The other question I had was relating to the all volatile water treatment building. That building houses the tech support center it says.

MR. WROBEL: That's correct.

CHAIRMAN BONACA: And it is not designed to resisted high winds or tornado/missiles. And the question that this consultant had when he reviewed was, in fact there is a requirement for the tech support center to be designed to withstand. So how

do you have this tech spec? Do you have a backup --

MR. WILSON: This is Dave Wilson, RG&E.

The technical support center is an addition to our treatment water building and it was added to satisfy the requirements of NUREG-0737 in order to have an emergency planning space, so to speak, and we put a diesel in there for backup power and whatnot. There were no requirements to make that seismic or to tornado missile protect it. If we had a seismic event or a tornado event, then the control room is where we operate from.

So the building is non-seismic and nonsafety related. It is, however, important enough to be within the scope of license renewal.

CHAIRMAN BONACA: I thought --

MR. WROBEL: I'm not sure where the qualification is. I know that it's required to be habitable, as habitable as a control room. But I don't believe that it need to be designed for external phenomena.

CHAIRMAN BONACA: I thought the emergency plan required that, but maybe I'm wrong.

MR. WROBEL: Not to our knowledge.

CHAIRMAN BONACA: So you have a tornado, you got a missile and it gets knock out, you have to

rely on the control room?

MR. WILSON: Yes, sir, that is correct.w We also have an EOF facility that's about 25 miles away that probably the same tornado wouldn't hit it.

CHAIRMAN BONACA: Yes. Okay. I'd like to find out more if it was a requirement, in fact, of the emergency plan or not.

MR. ARRIGHI: This is Russ Arrighi.

I don't have the answer for that right now, but I'll write it down and get back to you.

CHAIRMAN BONACA: Okay. Yes.

At this stage, I don't have anymore questions for you.

MR. WROBEL: I'm over my hour, so let me get through this last one.

CHAIRMAN BONACA: Yes.

MR. WROBEL: We had 29 how level commitments. It was actually 31. There were 2 more that were added that were not the docket yet. So these were 29 that were dockets. There's actually 31 commitments.

All of the commitments have been put into what we call our CAT system, our commitment action tracking system. They've all been assigned responsible personnel.

I would say about one-third to one-half of the commitments have already been completed. We plan on completing the vast majority of the commitments within the next couple of years. We're not going to wait until 2009.

Some of the commitments, and George can explain this even better, he sequenced them between now and 2009 to fall within a natural, like the tendon testing for 2005. We picked 2005 because that's when our next tendon testing test is scheduled. So, well, we're doing a lift off test that we would retention them at the same time. So that's why 2005 was picked. We probably could have done it out to 2007 or eight or nine.

So they're all assigned. They're internal documents. The fact that we had a matrixed organization, we don't really have a license renewal project person to turn over, because all the commitments were made in concert with the primarily engineering people that were assigned to the project. So there's not a major turnover process developed.

We do have a program to configuration management process that we're developing now. We're finding some of the ones that are not specifically

assigned, but in detail. We have that process. We haven't written a procedure yet, but we're following them on an individual basis for now until we get the whole program integrated with our configuration management information system. And we don't -- you know, they're all being followed in CATS right now, so I don't see any real issues in long term maintenance and meeting all of our commitments.

CHAIRMAN BONACA: Okay.

MR. WROBEL: They're all scheduled with due dates.

CHAIRMAN BONACA: And one last question. If you look at the SER on number of systems, the staff performed the review of the application, looked at your methodology for the defined components is scope. And then they identified cases where they disagree with you. They informed you, and you agreed that something else had to be added to the scope, there were a number of changes that were identified by the staff.

And, you know, we have to make a determination, as the staff has to do, that there is reasonable assurance that the items in scope have been identified. So I have the question also for the staff later on. You know, how based on the fact

that the staff, every time they perform the review of an LRA they find enough additional items that are in scope, and the applicant agrees. A thorough reviewer like yourself is left with the question in the mind, you know, do we have reasonable assurance to the fact that items in scope have been identified and proper programs have been implemented. And I would like to have your comments.

MR. WROBEL: Sure. We did a review again today looking at all the RAIs. We identified three items that were put into scope because of the staff review to date. Now, we have a couple of open items. Those were the house heating boiler in the screen house where it as a (a)(2) issue. We have a safe shutdown methodology that includes being able to safely shutdown without the screen house at all. We have a separate independent system that we can shut down. So we felt that even if the boiler degraded under (a)(2) and damaged the surface water system, that we could still safely shutdown.

What the staff pointed out in their review is that if the boiler degraded at the time that we were having recovery from a loss of coolant accident, that we would not be able to. So we hadn't put a house heating boiler degradation from

aging management program together with the recovery from loss of coolant accident together. We didn't do the analysis. But I think we have a pretty low probably. From a strictly(a)(2) reading it would have fallen in scope. And so we decided we would put that in scope.

The other two we were disagreeing with the staff for a while. We currently agree that we would have spent fuel pool makeup from the refueling water storage tank. We had called that a hypothetical event, and we didn't feel a hypothetical event needed to be in scope. We decided it would be prudent to put that into scope. It was a very minor amount.

CHAIRMAN BONACA: Yes.

MR. WROBEL: And the CCW, the rest of the component cooling water system, was really already being covered by component cooling water system program.

So those are the only three, other than some typographical errors. And I think that's what you're finding in the RAI responses is that there were some errors that were -- when we did our initial drawings that we sent in, and there were some errors when we were translating the magenta

lines to cyan lines. There were some errors that were made there. And they were covered very quickly.

CHAIRMAN BONACA: Okay. In fact, don't worry about those. Because, I mean, I don't worry about where you have a logical disagreement. I mean, you may be right. And I think you have to present your perspective and position, and that's only fair.

I'm worrying more about where there, for example, the ends of pipe missed purely because somebody made a mistake and then they're excluded. And that's really where --

MR. WILSON: This is David Wilson, Rochester Gas & Electric.

CHAIRMAN BONACA: Yes.

MR. WILSON: I'd like to field that for a second.

There's really two administration issues that happened, I think just because of the timing of our application.

The first one and most significant to your question or comment was when we originally had discussed with the staff how to prepare and package and transmit the application, we had prepared and packaged the application with a set of drawings that

had the colors of magenta showing the scope. And about 5 days before we were scheduled to submit, the staff realized that magenta was not a color that they could use for the rank and file reviewers that would print out on a laser jet printer. It would show no color, and they wouldn't be able to see the boundary. So we had to go back very quickly and modify the drawings, which was a total redrew. And errors were introduced in that. Those errors were not reflected in the actual analysis that was in the application.

And we had had a discussion with the staff. And, in fact, put in our application that this was going to happen. Everybody recognized it. But we felt at the time because of the data in the application was correct and reflected the correct boundaries, that we would be able to quickly navigate and get through this. And, in fact, we did. It was not a significant issue with the issue.

CHAIRMAN BONACA: Okay.

MR. WILSON: The second administrative issue was purely GALL related, and that's in that we had to both educate ourselves and we had a staff learning how to use the GALL. And when we were translating components that were within the scope of

license renewal -- see, the way it works, is a reviewer actually has a drawing in front of him. He can put his finger on a component and say tell me about valve 123. But nowhere in the application do you see valve 123. You see carbon steel components and spent fuel systems.

And so there's a lot of discussion that goes back and forth using the standard review plan on where is that component exactly in your application. And because we had to do this in a public venue, the discussion takes the form of an RAI.

But, you know, they're easy enough to work through. And, in fact, we found very few other than what was discussed omissions. And, of course, then the region comes in after the NRR staff is done and does their own review.

And so we understand what you're seeing, but we don't think it's representative of a technical problem.

CHAIRMAN BONACA: I appreciate it.

MR. WROBEL: All right. That was our last slide.

You have station blackout covered in yours?

MR. ARRIGHI: I have a slide I'll put up if they need to see the boundaries.

CHAIRMAN BONACA: We're going to take a break. We are due for a break at 2:45. I don't know if we want to break now and then go through the staff presentation?

MR. ROSEN: I'd like a break.

CHAIRMAN BONACA: You would like a break? Let's take a short break. Let's together here again in ten minutes, would you say?

(Whereupon, at 2:00 p.m. a recess until 2:15 p.m.)

CHAIRMAN BONACA: Okay. Let's get back into the session.

And now we have Mr. Arrighi that is going to summarize for us the SER.

MR. ARRIGHI: Good afternoon. My name is Russ Arrighi, I'm the project manager for the safety review of Ginna plant license renewal application.

With me is John Rowley. John assisted me in putting together the SER, and he's going to make the presentation on Section IV.

Also we have Mike Modes from Region 1. He's a team leader at the region 1 Inspection Teams, and he'll present the section on those inspections.

CHAIRMAN BONACA: Okay.

MR. ARRIGHI: The application for Ginna was submitted in July 2002. Ginna is a two loop PWR located in Wayne County, New York. As one of the oldest PWRs, Ginna did go through the Systematic Evaluation process review by the NRC. The Systematic Program was utilized by the staff, the review that document. It was utilized during the scoping and screening methodology audit. Also the staff review of scoping and screening in headquarters and during the regional inspection.

That Systematic Evaluation Program, SER, was used in the same manner as the UFSAR in that it established the current licensing basis of the plant.

RG&E requested a 20 years extension for Ginna through September 18, '29. Ginna's the third plant that implemented the GALL process with Fort Calhoun being one and Robinson being the other.

The staff review of the license renewal application resulted in eight open items. Four of those open items are presently resolved. The applicant has provided responses for the other open items. Preliminary review indicates that two or three of those other open items can be resolved in

this preliminary review. So, that's why we did not show that they are resolved.

There are seven confirmatory items. One of the confirmatory items, and we'll talk about these, based on a response the applicant provided to one of the open items, this confirmatory item is now considered essentially an open item. And when I get there in the application, I'll talk about that in a little detail.

The LRA resulted in several components being in scope. The applicant mentioned those. The heating steam boiler, the component cooling water piping and the fueling water storage tank, the makeup supply to the spent fuel pool.

As the applicant stated, a lot of the other components that you indicated, we had a number of RAIs bringing stuff into scope. Our questions with the applicant, they said they are in our database on site. They are already in scope. But, again, we had to get that on the docket, so that's where a lot of those things are that made the review seem like there was a lot of additional components added.

MR. LEITCH: Russ, is that house heating boiler sometimes referred to as the screen house

steam heating boiler or is there a difference?

MR. ARRIGHI: Yes, steam heating boiler. I think we might have used the term steam heating boiler in the SER. I don't know all the terminology.

MR. LEITCH: I thought I saw it a screen house.

MR. WROBEL: It's in the screen house. Yes, it is the same boiler. It's physically in the screen house.

MR. LEITCH: Okay. Same boiler.

MR. WROBEL: Yes.

MR. LEITCH: Okay. Thank you.

MR. ARRIGHI: Also, as result of the SER review there was one new aging management program added, and that was in the electrical section. It had to do with electrical cables not subject to EQ requirements, used an I&C circuit. That's using circuits with sensitive low voltage signals, and that program was added based on staff questions.

For Ginna, we did have 224 RAIs were issued at Ginna. This is a reduction from the previous applications, however it is still a high number. Again, due to the three GALL applications

being submitted relatively close together, the full benefits of GALL weren't realized.

MR. ROSEN: When is that going to wear out?

MR. ARRIGHI: Probably after at least Summer.

MR. ROSEN: Summer. We get another pass on Summer and then after Summer?

MR. ARRIGHI: Yes, we'll see what happens then. But with the new process, we expect that the number of RAIs should be reduced.

CHAIRMAN BONACA: Yes. We review Summer in the winter. In mid-December. And then --

MR. ROSEN: To warm us up.

CHAIRMAN BONACA: -- that no open items, I understand.

MR. ARRIGHI: Yes. Summer has no open or confirmatory items.

All right. The NRC audits and inspections, there were two inspections and two audits performed at Ginna. Each of these will be discussed as we progress through the presentation.

Structures and components. The staff review and audit determine that the applicant's scoping and screening methodology satisfied the

rule. During the audit, again, as a result of the audit we did bring in the screen house, the heating steam boiler in scope. And, again, the applicant discussed that based on the SEP seemed to have an alternate means to shut down the plant. Alternate service water supplied to the diesels.

Plant level scoping results. A staff review of this section determined there were no plant level systems, structures or commodities omitted from the application.

Scoping and screening of mechanical systems. Before I go a little further on this slide, I know a question normally arises regarding the pressurized spray head. The pressurizer spray head at Ginna is not in scope. The defuser portion. The spray nozzle --

CHAIRMAN BONACA: The spray nozzle is?

MR. ARRIGHI: -- is in scope and that's the pressure boundary portion.

CHAIRMAN BONACA: Now, is this normal?

MR. ARRIGHI: Yes.

CHAIRMAN BONACA: The nozzle is in scope?

MR. ARRIGHI: Yes. The pressure boundary function of the spray is always in scope at

all applications.

CHAIRMAN BONACA: Okay.

MR. ARRIGHI: Again, at Ginna and I think at the previous applications, the failure of the pressurizer spray head wouldn't prevent the safety accomplish to depressurize the plant. As part of Ginna's current licensing basis, they rely on an alternate means to depressurize a plant for fire protection safe shutdown analysis. And the way they depressurize would be through their PORVs. Again, normal plant operation, they would use the pressurizer. And, again, any indication that they had a problem with the pressurizer function, again, normal plant operations the operators would be aware of it, it would go in their corrective action process and they would fix it. But for the purpose of license renewal, again, the current licensing basis to depressurize during a cool down is the PORVs.

Okay. Section 2.3 Scoping and --

CHAIRMAN BONACA: Could you go back to that? This is for the fire, right?

MR. ARRIGHI: Yes. For the fire protection safe shutdown analysis.

CHAIRMAN BONACA: Okay. Okay.

MR. ARRIGHI: They rely on the PROVs.

CHAIRMAN BONACA: The PROV.

MR. ARRIGHI: Okay.

MR. LEITCH: I guess there's one issue that I find just a little confusing in the SER in page 1-10 there's a statement made that redundancy is not an adequate basis in itself to exclude a system from the aging management review. And I guess --

MR. ARRIGHI: If the current licensing basis specifies it be redundant equipment, then all that equipment if it's part of the CLB, would need to be in scope. Just because there are other components that can perform the same function, those types of components, you know, you might have ten means to fill up a tank. If the CLB relies on two of them, both of those means have to be in scope, not the remaining ten. Or in the case of the CLB only requires one method, just because you have other methods to perform that function if you're not managing the aging, we can't credit those and we have to rely on the CLB. And therefore, those systems that are defined by the CLB have to be in scope.

MR. LEITCH: So I'm just trying to go

back to this pressurizer spray nozzle. There are other methods of depressurizing, but --

MR. ARRIGHI: And the licensing basis of this plant relies on the PORV, the power operated relief valve.

MR. LEITCH: Okay.

MR. ARRIGHI: So therefore the staff, since it's part of the CLB, can require that that component be in scope. And if that component is not part of the design in the CLB, then we can't rely on it and it would essentially be -- we can't force the applicant to put it in license renewal.

MR. LEITCH: Okay.

CHAIRMAN BONACA: Normally the position taken is that if the spray head fails, you can still depressurize with a spray at a lower rate, but still adequate to get into closer down with 24 hours, or whatever the requirement is. And now this is a new one, I haven't seen before, you use a PORV to depressurize as a means. I guess I hang my hat more on still using the pressurizer.

MR. ARRIGHI: I'm sure the applicant could probably perform that same analysis and make the same case.

CHAIRMAN BONACA: Right. Yes.

MR. ARRIGHI: But their licensing basis was clear in this regard.

CHAIRMAN BONACA: Yes. Okay.

MR. GILLESPIE: Frank Gillespie with NRR.

This comes up. The safety case is first versus the compliance case. And part of that safety case is, it wasn't relied upon in the CLB for a reason. And the reason it wasn't relied upon is some of the things you articulated.

The other thing is the spray heads, and this is only the heads, it's a low-DP system and it's used frequently. So while it is a passive component, it's kind of in active use. And so now you have to postulate the sudden degradation of this head falling off, not in daily use. At the same time you have the accident that needs it, and you still have water flow through a depressurizing the pressurizer anyway.

So the safety reason is the first reason why it's out, but that manifests itself in not being in the current licensing basis. So it's not just compliance, it is safety.

MR. ARRIGHI: Again, Section 2.3, mechanical system review. The staff review of this

section resulted in three open items and three confirmatory items. Three of those open items have been resolved.

Several components that were initially omitted from the scope, again, we stated these earlier. Steam heating boiler, component cooling water piping and spent fuel pool makeup path were all added to scope based on the staff review. Again, the steam heating boiler was brought in as a result of the scoping and screening methodology audit questions that were asked them. The other two components, CCW piping and spent fuel pool makeup. they were added as a result of applicant's response to these open items that follow.

Open item 2.3.3.2-1 is resolved. The staff identified that failure of out-of-scope CCW piping could result in failure of the system and the ability to cool down the plant.

The piping in question here is nonsafety related piping that is subject to AMR and review that ends at an open boundary valve. In this case it's a 3 quarter inch valve piece of pipe that the applicant had an open boundary valve. And initially they deemed that hey would sufficient time to isolate those valves prior to losing the component

cleaning water surge tank and have sufficient capacity to water. The staff asked the applicant to address the basis to support that information; what size leak, etcetera.

Preliminary review of different types of failure, the applicant came back and said as a result of your question, we will add in whole component cooling water system piping down stream of that valve. So the CCW system is in scope of license renewal at this point in time.

Open item 2.3.3.3-1. The staff identified that the spent fuel pool makeup source was not in scope. Again, the applicant's position was initially that it would take over 5 hours. If the hypothetical event, it would take over 5 hours to initiate boiling and then over 2 days before you need to add water. The applicant didn't account for potential leaks in the spent fuel pool liner. And, again, the rerack of the spent fuel was based in part on having a makeup water supply to the spent fuel pool.

As a result of communications with the applicant, they agreed that they would add in the feeding water storage tank into scope, and therefore this item has been resolved.

CHAIRMAN BONACA: So the issue was whether or not a leak from the pool had to be addressed?

MR. ARRIGHI: Correct.

CHAIRMAN BONACA: All right.

MR. ARRIGHI: Exactly.

CHAIRMAN BONACA: I mean, the design basis of the spent fuel pool was not clear about that?

MR. ARRIGHI: In some of the documentation it talks about a hypothetical failure and whatnot. And it doesn't really address leakage. During our review of some, you know, rerack analysis and just the staff thought it was needed, that they needed to address leakage.

CHAIRMAN BONACA: Has this been done for the other previous applications?

MR. ARRIGHI: I believe all the other applicants have a makeup source to the pool. I'd have to ask the reviewer.

MR. JONES: This is Steve Jones, Plant Systems Branch of NRR.

In the case of Ginna, the earlier amendments regarding spent fuel capacity or pool expansion did address leakage through the liner and

relying on makeup to maintain pool level.

Ginna has a somewhat different licensing basis, in that they have a temperature limit on the pool below boiling, so they rely on the cooling system to maintain the temperature limit. And I think that's the -- in general we bring the makeup systems into scope based on boiling. In this case it was to address leakage that could render the cooling system inoperable and then you would not be able to maintain the temperature below the design temperature.

CHAIRMAN BONACA: All right. Okay.

MR. LEITCH: Can we talk about the steam heating system in the diesel generator building? It seems as though what they did was see where the steam heating system could fail in such a way that it would damage safety related system. Even though the steam heating system in itself is not safety related, it could fail in such a way that it would damage the building or damage safety related equipment. And those parts of it that could fail were brought into scope.

Now, I guess a number of applicants that we've see in the past have said, well, basically if you have a two over one kind of a situation if

anything in that building would be brought into scope. It sounds like what they did here was part of the steam heating system and the diesel generator was brought into scope and other parts of it were not. I mean, I would think that in that kind of a situation, I think what we've seen most previous applicants do is just bring the whole steam heating system in the diesel generator building into scope?

MR. WILSON: This is David Wilson, Rochester Gas & Electric.

And, in fact, that is what occurred. I think what you're seeing in our case is we're the first applicant to actually address the nonsafety specs safety ISG in their application.

And so the original thrust, when we did our original reviews, we did an analytical review based on our current licensing basis, which did not identify house heating steam as being in scope. Then we did a spacial analysis that identified in certain areas of the plant house heating steam could in fact cause a failure that would affect the safety function. That brought the entire house heating steam system into scope, but you screened out the components that didn't cause that failure.

So, the system, house heating steam, was

in scope but only the components in the diesel rooms initially were within the scope of license renewal.

MR. LEITCH: Yes.

MR. WILSON: And then later on, based on RAIs and the audit which identified that post-accident we could have a failure in the screen house that would affect our ability to manage the accident, we bought in additional components. But the system was already in scope in the original application.

MR. LEITCH: Okay. Okay. thanks. I understand.

MR. ARRIGHI: Item 2.3.3.6-1 is the jockey pump. The staff identified that the fire service water booster pump of the jockey pump was not in scope. Loss of this function could cause of the fire pumps and damage them, therefore the staff thought it should be in scope of the rule.

And you heard the applicant state that they do have the pressurized storage tank, which is a 1,000 gallon tank pressurized with 100 pound air. And that's what they state maintains the pressure in the system.

Again, initial discussions the applicant included the tank for personal safety reasons and it

wasn't initially because of maintaining the pressure in that tank.

The staff's review is that the applicant's 1979 submittal for the fire protection evaluation and the FSAR are both clear, and they both state that both the jockey pump and the storage tank maintain system pressure, not just one. Therefore, it's the staff's position that both the jockey pump and the storage tank need to be in scope of the rule.

Again, the applicant and the staff are in a little disagreement at this time. And we're working toward resolution on this item.

CHAIRMAN BONACA: Is this one of the outstanding?

MR. ARRIGHI: Yes, this item is not resolved and this is still --

CHAIRMAN BONACA: One of the two?

MR. ARRIGHI: Yes. This is essentially one of two open items that we have that we're still evaluating.

Confirmatory item. This has to do with the component water surge tank, the makeup not being in scope. It was the initial response from the application on the docket said that the makeup water

source would be included in scope. However, due to the open item regarding the component cooling water, the -- related to open boundary valves. By putting the whole component cooling water system in service in scope.

It's the applicant's position that the makeup water supply to the surge tank does not need to be in scope and that the component cooling water surge tank has adequate capacity to accommodate for any leaks.

It's the staff position that it's the USSAR and the safety evaluation review of the Systematic Evaluation report both specify that you can postulate a leak following an accident. And in there it goes on to state that the makeup capability should be able to cope with normal system leakage post accident. Therefore, it's the staff's position that the makeup water is part of the current licensing basis and that makeup supply is required to be in scope.

And, again this is a second item that the staff and the application are discussing.

CHAIRMAN BONACA: But you say though there, was initially brought into scope and now?

MR. ARRIGHI: Well, again, when we put

the SER on the, with open arms in the docket, at that time we had a response on author affirmation from the applicant that said yes we will include the makeup supply. But at that point in time they didn't have an aging management program to monitor, to mitigate aging of the whole component cooling water system. So they thought, all right, to accommodate any leakage, since that piping's not in scope, we'll have the makeup. But now that they've added the whole system in scope, they said that packing leakage would be small and therefore our surge tank would have adequate capacity.

Section 2.4 structures and structural components. There were no open or confirmatory items in this area.

For Section 2.5 electrical systems and instrumentation and controls. The electrical components were evaluated on a plant wide basis versus system basis. There was one open item in this area. The staff identified that two cables from off-site power that brings power to safety buses which power the service water pumps were not in scope of license renewal. And the staff asked can the applicant get to cold shutdown without the use of service water pumps.

The applicant stated that they have the capability to get to a safe shutdown condition without the use of service water. On a station blackout, they would essentially use the aux feedwater to supply water to the steam generator to go solid and cool down through a feed and bleed on the secondary side. And use the PORVs, essentially, to depressurize.

So it's the applicant's position that those components are not relied on. The service water pumps are not relied on as part of the current licensing basis to get to a cold shutdown condition.

MR. ROSEN: Are the PORVs qualified at passing water, solid water?

CHAIRMAN BONACA: Good question.

MR. ARRIGHI: I don't know. PORVs qualified?

MR. WILSON: This is Dave Wilson, Rochester Gas & Electric.

The PORVs in the pressurizer, they're only used to depressurize the RCS later on in determination of this evolution. The feed and bleed actually occurs using auxiliary feedwater into the steam generator and then draining the water out of the steam generator through manual valves, not

through main steam safety valves or main steam atmospheric relief valves.

MR. ROSEN: So it's the secondary side?

CHAIRMAN BONACA: It's a secondary.

MR. WILSON: Secondary side. Correct, sir.

MR. ARRIGHI: And the PORVs would just maintain the depressurization for the primary,

And the applicant did supply the response to that. And the staff is currently reviewing this issue.

Scoping and screening summary. Pending the final resolution of the four open items, being the docketed information and resolving the other open item, the scoping and screening results include all structure system component within the scope of license renewal and subject to an AMR.

At this point of the presentation, I would now like to turn it over to Mikes Modes. He's with Region 1. He was the team leader that did the inspections at the site, the scoping inspection and the aging management review inspections.

MR. MODES: This is Michael Modes.

We followed the prescribed license renewal guidance insofar as the inspections were

concerned using primarily IP 71008. And the inspection plan was developed specifically for that site. It was the first goal at Region 1 I've ever done. So the inspection started with what the goal called for and worked its way completely through to the actual procedure reviews and aging reviews at the plant, interviews with individuals and walkdowns.

And we used a number of individuals in the plant in the region. We tried to use a structural individual with that kind of -- metallurgical, mechanical and operations. We's borrow heavily from the experience of the resident inspector.

Next slide.

For the scoping and screening, for example, it was a pretty clean inspection. It seemed to be more a matter of timing. We appeared to have arrived when there was a review being performed, for example, by the fire protection engineer to determine whether or not the right number of valves and stuff were being called out in the scoping. There was a corrective action generated as a consequence of the inspection to bring closer correspondence between the two databases.

We also found in example for the screening for the aging inspection that a lot of the stuff was more a degree of refinement. We had sort of caught them in a point where they were transitioning from the processing of being philosophical about aging license to the actual implementation. So there were a number of corrective actions that were identified in the nature, per se.

They were taking advantage of a certain program that contained a procedure that didn't clearly identify, for example, what aging mechanisms ought to be regularly reviewed for bolting. So in that regard, we had to dig pretty deeply to come up with any issues. The documentation was comprehensive. They have excellent database. And it's been my personal experience with Ginna there's a lot of pride in craftsmanship. You don't see a large turnover in personnel, so you get a lot of corporate knowledge answers. Pretty good inspection.

MR. LEITCH: Mike, were you involved with the June inspection? I'm a little confused. I have some questions regarding the June inspection.

MR. MODES: The scoping?

MR. LEITCH: Yes.

MR. MODES: Yes.

MR. LEITCH: Okay. It seemed to me that there were a number of issues there dealing with fire protection and with the fire program.

MR. MODES: Yes.

MR. LEITCH: I guess a number of those had to do with frequency, that is the frequency of Halon testing, the frequency of fire door inspection, the frequency of hydrant inspection. Also some issues concerning the frequency of flow testing, qualification of personnel and so forth.

I guess I came away with a little bit of an uneasy feeling regarding the fire protection program. And I don't know if that's justified or not, or --

MR. ARRIGHI: Can I answer that?

MR. LEITCH: Go ahead.

MR. ARRIGHI: I think the inspection you're talking about is the aging management program audit, which is a little later, which the staff reviewed the project manager and a number of people from the staff.

MR. LEITCH: Right.

MR. ARRIGHI: And, again, I'll be

getting to this. But we were doing a consistency with GALL audit to make sure that the applicant's ten attributes meet the GALL attributes.

It was, as you state, in the application they said these two fire protection programs were consistent with GALL.

MR. LEITCH: Right.

MR. ARRIGHI: When we went on site and looked at the basis document, those issues that you brought up were clearly stated in the applicant's basis document that they had exceptions for these specific attributes. And I believe it was, I guess, an oversight on the applicant's part. I don't know if these programs were developed after the submittal of the application, but they didn't -- once they identified these exceptions, due to an oversight or whatnot on their part, they didn't inform the staff of those exceptions. So during the aging management program audit we identified them. Again, they jumped out off the page. And we issued a RAI request of information to the applicant. And they forwarded those responses to the staff. And they were subsequently reviewed and approved.

But, again, the applicant was aware of those exceptions. But, again, you'd have to put the

SM why it wasn't forwarded.

MR. LEITCH: Okay. Well, the inspection report seems to indicate that in some cases these exceptions have been identified, but in other cases they weren't identified.

MR. ARRIGHI: Yes. There were eight exceptions. Six or seven of those exceptions were clearly called out in their basis document. There was one, I can't recall which specific one it was, a frequency test of 6 months versus 2 years; I can't recall off the top of my head which exception wasn't clearly called it.

MR. LEITCH: I think there was one related to the qualification of personnel doing--

MR. ARRIGHI: It may be the one that the staff identified on their own. And, again, the applicant included that as an exception and put that response on the docket. And that exception was reviewed by the staff.

MR. LEITCH: So these frequencies were then brought into compliance with GALL or they stand as exceptions?

MR. ARRIGHI: They stand as exceptions and the staff reviewed those exceptions. And based on surveillance test or results, the staff approved

those exceptions based operating history and whatnot. I'd have to go to --

MR. LEITCH: I guess my question is that perhaps one or two of these exceptions may be understandable, but it seems to me that there's so many exceptions all related to the frequency of doing certain testing with respect to fire protection equipment, which is real important stuff. I mean, I just wonder why there are so many exceptions in this one particular area?

MR. WROBEL: George Wrobel.

We refined the program basis document quite a bit, and we had a lot more extensive review of the docket when we submitted the application. Subsequent to that, we did a lot more analysis and evaluation of the attributes.

We have a plant specific design analysis that was done was specifically for the exceptions that were taken there. And so those particular exceptions were justified based on the information that was plant specific. We're doing all of the testing and surveillances that are requested by the GALL, but aren't the specificity of the -- you know, the timing is different, but we have a plant specific design analysis that justified that.

So some of that was just caught as we were going through a more detailed review developing our program basis document that we had when we did the application. And we didn't supplement our application when we found those, because we knew there audits coming and they would be developed at that point.

So, there's no open items and there's no inconsistencies. I mean, they're different, but they're not bad for us.

MR. LEITCH: Yes. But I guess all the frequencies that -- I mean, there are a number of things where the frequencies are just less than that prescribed in GALL.

MR. FRUMKIN: This is Dan Frumkin from the staff.

I think what we found in reviewing these, for example, the fire doors and the Halon system frequencies, is the frequencies for aging management does not need to be nearly as strict as the frequencies for the wear and tear on the active component wear and tear.

So a fire door might be inspected every week or every day that they might walk through a fire door. But to go look at the door for aging

features like aging degradation, that could be done on a less frequent basis.

So as far as operability, those things are being analyzed and are going to be done on a fairly code compliant basis, whereas aging management type inspections, which can be much more intense, are going to be done on less frequent basis.

MR. LEITCH: Okay. That's good. That answer make sense to me, although it perhaps raises the question about there's nothing really different about Ginna. Perhaps the GALL is overly restrictive in what it's suggesting as far as aging management frequency.

MR. WILSON: This is Dave Wilson, Rochester Gas & Electric.

One of the things we found in both fire protection and service water systems that comes into play here is the water chemistry of the water source lead for our fire water system. It's either city water or its Lake Ontario water. And Lake Ontario water's got a pH of 7 and very low chemical content. And that actually does come into play when you look at how you system degrades.

And so a plant that might use a

different type of water or have different water chemistry for their water source would have, by necessity perhaps, a different frequency of inspections.

So for our facility being fed from Lake Ontario or having treated water, one of the two, we're able to have lots and lots of operating experience that shows how often we need to go in to flush or whatever process we need to do. And it may be different for every facility.

Not that I want to defend the GALL.

MR. LEITCH: Okay. Thank you.

MR. FORD: I have a question for you, Michael. You said a curious phrase. You said that the aging management programs were conceived and they're full in philosophical sense, I think it is.

MR. MODES: Yes.

MR. FORD: But the intimation, the reduction to practice wasn't what it should be. IS what you meant?

MR. MODES: No. When you do the inspections from the viewpoint of if you will, where the rubber actually meets the road versus the esoteric reviewing a license application, what you find out is many times the timing of the inspection

to support the NRR review process does not, in fact, arrive at a period of time when the programs have been fully revised or fully implemented. So although they may in the application identify a certain program, when you get down to the procedure level you find out that certain nuances haven't been included. That's what I meant; the difference between a philosophical approach and -- I'm speaking from a very pragmatic viewpoint.

MR. FORD: Yes. So this question the details --

MR. MODES: Yes. Right.

MR. FORD: -- as you say, it's precisely those details that I'm questioning. For instance, on the one time inspection and many others. It's the details that I'm concerned about. And are you saying that from your view they haven't yet reached those level of details?

MR. MODES: No. I'm saying in a number of cases that's what we identified.

MR. FORD: Okay.

MR. MODES: Or to put it another way, the things that we did identify were the nuances. It's supposed to be a positive comment, not a negative one.

MR. FORD: Okay. Thank you.

MR. MODES: And the last slide, what did you call that "a meadow?" I don't know if I like that. Being from the region and working so arduously on that set of green indicators. But, yes, it is a meadow.

DR. WALLIS: Well, there are unexpected things to be found in meadows.

MR. FORD: It looks more like a lawn to me. A meadow has flowers in it.

MR. MODES: Although I will quote him.

MR. ARRIGHI: All right. Moving on.

MR. LEITCH: Just another question for Mike regarding plant security, the inspection report states the plant security is not within the scope of license renewal, yet I think we have seen certain elements of plant security, particularly those elements necessary to support emergency planning activities in the scope of other license renewal applications.

MR. MODES: Well, there were some components. I believe the whole security -- I don't remember how the break is. If you could help me here, Dave. I did assign one of the inspectors the task of looking at the security system. And I don't

recall if it was because that part of the system was out of scope or in scope, but we did review it and it was appropriate.

MR. LEITCH: Yes. Okay. I wasn't thinking so much about this security system, per se.

MR. MODES: It's not that it's in the GALL.

MR. LEITCH: As perhaps the building.

MR. MODES: Right.

MR. LEITCH: And the ventilation system is okay with the building, and things of that nature where you need to maintain that functional.

MR. MODES: And the parts, for example--

MR. LEITCH: For example, the planning sense, not necessarily the --

MR. MODES: The UPS, the uninterruptable power source to the security computer system, etcetera?

MR. LEITCH: Right.

MR. MODES: That was all looked at.

MR. LEITCH: Okay.

MR. MODES: Yes. It's not like we didn't look at it.

MR. LEITCH: Okay. Thank you.

MR. MODES: Yes.

MR. ARRIGHI: Okay. Moving on to Section 3, the aging management review of a GALL divides a system, the system into six groups.

Aging management programs. There are a total of 33 aging management programs and 30 were consistent with some deviation, and three were non GALL AMPs. Again, in the application enhancements means that those that augment the GALL and deviations are those that do not agree with GALL.

And again, we had AMP, one aging management program was added. And in this section of aging management programs, there were two open items and one of those is currently resolved.

You brought up the June inspection or audit here. This is the staff's aging management program audit. Again, the purpose of the audit was to verify consistency with GALL. The bottom line was that the staff concluded that AMPs were consistent with GALL except with those two exceptions on the fire protection program and the fire water systems programs. And we discussed those a little earlier.

In the reactor system, Section 3.1, systems are broken down into --

MR. LEITCH: I just noticed that the

fire protection requirements had originally been specified in the technical specifications. And then I think they were moved to the FSAR?

MR. ARRIGHI: Or the Technical Requirements Manual.

MR. LEITCH: And now they're in the Technical Requirements Manual. Do you see any connection, I mean between -- I don't know of the Technical Requirements Manual is less rigorous from the licensee's viewpoint in the tech specs, but I mean does that suggest, perhaps, why some of these differences in frequencies and so forth crept into the fire protection program?

MR. ARRIGHI: In my experience as an inspector in my past life, I would say no. Even if the systems in tech specs are not in tech specs, you know my experiences that the applicant, you know, implements those requirements. You know, I think by putting them in the Techs Requirement Manual they can make changes easier than getting a tech spec amendment. But from my experience, I wouldn't attribute it to that.

I don't know if you have a --

MR. WILSON: This is Dave Wilson, Ginna Station.

In fact, the equipment that's in the scope in our application for fire protection, it's greater than the sum of the equipment described in our Technical Requirements Manual or UFSAR. And the reasoning behind that is pretty straight forward. The staff had a lot of early issues that resulted in an ISG which had to do with the identification of equipment required for 10 CFR 50.48, I think it is, fire protection rule, and Appendix R. And the staff had, you know in my opinion or our opinion, a pretty reasonable position on some utilities having a complex and hard to understand licensing basis. I believe the early applicants had just Appendix R equipment in scope for the rule, and later on went back and adjusted.

We did not fall into that trap. When we scoped our fire protection system, we laid out our entire licensing basis, you know, original construction up through Appendix R and today, and put all of that equipment in scope, regardless of whether or not it was TRM. Where we differentiated was, you know, it's clear in the application that certain fire protection features are included for insurance purposes in out buildings and things like that. So that did not come into play in these fire

protection questions.

I am a little bit you know not taken back but concerned, I guess, if we're leaving you with an impression of the utility that we're not managing our fire protection system. I think what we're seeing here is more growing pains in the GALL and the Standard Review Plant format than any technical issues.

We put a lot of stuff into scope. And, you know, the really argument that we have really with the staff is over the jockey pump, which costs $274.

MR. LEITCH: Okay. Thank you.

CHAIRMAN BONACA: I have a question before we move on. I asked the question before regarding the battle former bolts, you know, they replaced 56 out of 728. And that's because they found defect-like. And what I found is that they have committed no further inspections to be performed. And I was asking the question of why would it be a logic that says you know, you don't need to inspect them anymore. Any comment on how you accepted? This is not an open item, I understand.

MR. ARRIGHI: Barry Elliot.

CHAIRMAN BONACA: Yes. This is the baffle former bolts where they in 1999 after 30 years of operation they found a number of them were defective. They replaced them. There were 56 out of 700 plus.

MR. ELLIOT: I'd say our position on the baffle bolts were --

CHAIRMAN BONACA: I would like to understand what your views of, you know, the fact that they don't need to inspect anymore this baffle former bolts.

MR. ELLIOT: Okay. We don't agree with that entirely, that they don't have to inspect.

Our position on the baffle former bolts is that they're part of the reactor vessel internals program.

CHAIRMAN BONACA: Right.

MR. ELLIOT: And the industry through the MRP is developing data on baffle former bolts, aging effects like irradiation assisted stress corrosion cracking, fracture toughness. And from this data they are going to propose a program for industry.

As far as this particular application is concerned, they have committed to implement the MRP,

whatever that program is. Our concern is that this application, this particular applicant is going to go into license renewal in 2009 and that the MRP program may not be completed by then. So we've asked them to commit that prior to entering the license renewal program, that they will have either the MRP program or submit one of their own for all the internals. And that's our position; that there needs to be part of the license renewal term an internals inspections program. And, of course, baffle former bolts would be part of that.

CHAIRMAN BONACA: And they have agreed to that? They have agreed to that?

MR. ELLIOT: Yes, they have.

CHAIRMAN BONACA: Okay.

MR. ELLIOT: Well, they could talk for themselves.

MR. WROBEL: Yes. George Wrobel from RG&E.

We agreed that we would submit an internals inspection program prior to the period of extended operation. We haven't decided exactly what we're going to do on baffle former bolts. We're one of the four plants in the country that have looked. No one else has even looked yet. And we found so

little degradation, and we feel that there's so much margin that at this point we're not ready to commit to actually doing more detailed inspections of the bolts. But, you know, that could change. Right now we don't see the need for it. And I'm not sure what the schedule for MRP is on that.

I'll pass that along.

MR. ELLIOT: I'll pass that along.

I want to give you some information. We had a meeting with the MRP within, I don't know, a week or two ago. And I told them that you needed this stuff by 2009. And I think you better get on them, because they were under the impression the lead plant was Oconee. And they could use Oconee as a lead plant. But I think you come before Oconee as far as needing this program.

So, I think you need to talk to them.

CHAIRMAN BONACA: Well, I hear two things here. I hear that they need to do this, and I hear you saying that you're not committing to anything particular? Are you committing to a list, say with MRP, and follow industry insights and recommendations?

MR. WROBEL: We do that as a matter of course, so we'll continue following MRP and what's

going on.

The internals commitments that we made were a little bit different then that. We did commit that we would look. Before 2009 that we would have a program that could detect cracking .0005 mil or something like that. That's a program that we're more actively pursuing, because we haven't done that one before.

CHAIRMAN BONACA: Okay.

MR. WILSON: And we're following what the boilers are doing in that area. The baffle bolts, like we say, we had one percent degradation so it seems to be a lower priority. But we will continue working with MRP and if they develop an industry position, then we'll be evaluating that.

CHAIRMAN BONACA: Why did you replace those 56 bolts if you didn't find there was a problem with those?

MR. GEIKEN: This is Gerry Geiken.

Actually, I'd like to clarify one thing. We found one bolt, out of all of those bolts that we inspected, that exhibited evidence of ISACC.

CHAIRMAN BONACA: Okay.

MR. GEIKEN: All the other indications, UT indications were false/positives. We extracted a

number of bolts and tested them to distraction of the Westinghouse hot cell. We couldn't verify one indication.

So we really saw very, very little evidence of IASCC.

The other thing is, we did a proactive replacement. Those 56 we decided to proactively simply extract and replace with 316.

CHAIRMAN BONACA: Hopefully, by the time we get to the final Committee meeting, there will be some particular understanding of how this is going to be handled. I think I understand it. But, you know, if you have expectations, there has to be responding willingness to meet the expectation.

So, okay.

MR. GILLESPIE: Hey, Russ. Frank Gillespie.

What is the expectation today? Because it's not zero.

CHAIRMAN BONACA: I'm asking, you know, you have stated an expectation that 2009 there will be in fact a clear commitment of what they're going to do.

MR. ELLIOT: No. The commitment is now.

CHAIRMAN BONACA: Yes.

MR. ELLIOT: But prior to 2009 they have to have given us a program for the reactive vessel internals for inspection for what they think needs to be inspected, the frequency of inspection, the acceptance criteria; all of their requirements for an inspection program has to be submitted and approved by us by 2009.

CHAIRMAN BONACA: And that will have to include the baffle --

MR. ELLIOT: And the baffle bolts will be part of that program.

CHAIRMAN BONACA: Now, they may still convince you by that time that they don't need to inspect those baffle bolts. Can they convince you of that?

MR. ELLIOT: Have they convinced us that they don't have to inspect them?

CHAIRMAN BONACA: Can they convince you by the time they submit the program?

MR. ELLIOT: Well, see, the MRP is looking at the bolts.

CHAIRMAN BONACA: All right.

MR. ELLIOT: And I think if I was them, I would look and say certain amount of radiation causes a certain amount of degradation, and then I'd

just look at my core and say, okay, how many of those do I have to look at before -- you know, and that's it. And then you would say I would inspect so often to assure that it doesn't degrade.

CHAIRMAN BONACA: Okay.

MR. ELLIOT: And that's what I'm hoping the MRP is going to come up with. Right now they're just generating the data about what it takes to get irradiation assisted stress corrosion cracking of baffle former bolts.

CHAIRMAN BONACA: Yes, I understand.

MR. ELLIOT: So we don't have that data yet.

CHAIRMAN BONACA: Have more data that aspire of this MRP program, they will come up recommendations on what need to be inspected and how frequently?

MR. ELLIOT: Yes.

CHAIRMAN BONACA: Okay. Now their recommendation may not include a recommendation for inspection of baffle former bolts, right?

MR. ELLIOT: It might not. That's right.

CHAIRMAN BONACA: Might not, and you would leave that?

MR. ELLIOT: Right, and we'll review it.

CHAIRMAN BONACA: And I think you both agree on this issue. So I don't see disagreement of that. No, I'm trying to understand it.

MR. ELLIOT: That's good. Because I hear --

CHAIRMAN BONACA: I hear this professional side, and I'm waiting to hear some other things from the other side.

MR. GILLESPIE: So right now they're committed to following the MRP when the MRP results come out. And if the MRP don't come out by 2009, they're committed to submitting a plan for NRC approval?

MR. ARRIGHI: Yes.

MR. GILLESPIE: Is that a condition of the license?

MR. ARRIGHI: That's a commitment. It is a commitment at this time.

MR. GILLESPIE: Okay. And there's a commitment that they'll submit it. That's not review and approval. So what we have --

MR. ARRIGHI: Pretty straight. No, it was a commitment to review and approval.

MR. GILLESPIE: Okay. So that that

limit is on there.

Mario, because we're not going to know any more technically between now and the full Committee meeting.

CHAIRMAN BONACA: That's right.

MR. GILLESPIE: So what we've got is a process in place that the licensee is going to submit for approval a plan prior to 2009 or MRP, whichever comes first.

CHAIRMAN BONACA: Well, it took me this long to understand --

MR. GILLESPIE: And --

CHAIRMAN BONACA: Now I understand it, and I think we can go to the full Committee meeting with that.

MR. ARRIGHI: Okay. All right. I'll move forward.

Again, Section 3.1, reactor systems. There were two open items. One was resolved.

Item B2.1.28-1 had to do with the reactor vessel surveillance program. This item involved testing of the surveillance capsule in the core after it received a neutron fluence of 60 years. Initially the applicant wasn't planning on testing the capsule. Again, this was not consistent

with GALL. The applicant subsequently came back and agreed that they will test the capsule once it reaches a fluence for 60 years.

The open item B2.1.36-1 thimble tube inspection program. GALL doesn't have a corresponding program and this was reviewed the Standard Review Plan. Several of the attributes, I think five of the eight attributes the staff needed further clarification and information to approve this program.

The applicant has subsequently provided the information. Again, preliminary information looks like the information is okay, however it's still under staff review. So this item is not resolved, but we're evaluating the information they provided.

MR. FORD: Now that information included things such as the qualification of inspection techniques for cracking and things of this nature?

MR. ARRIGHI: Barry Elliot.

MR. ELLIOT: This is Barry Elliot.

I'm just going to give you a whole picture of the thimble tube programs.

There's two parts of the thimble tube. There's a thimble tube and the guide tube. The

original thimble tube inspection program was for flow induced vibration. And when the applicant made the evaluation of the thimble tube and the guide tube, they also identified that cracking was an aging effect for both the thimble tube and the guide tube because they're stainless steel and they're in a PWR environment water.

The problem is they didn't have an inspection program for cracking. So we asked them to provide the ten attributes that we have in our review plan for programs and to identify how the existing thimble tube inspection program would satisfy for cracking. The existing one was for flow induced in vibration.

They modified the thimble tube inspection program to use eddy current inspection, use the same eddy current but look for cracking, qualify it to their experience with inspection by eddy current, their eddy current in the plant. And the acceptance criteria, since you can't really detect the depth using eddy current, any defect would be considered to be unacceptable and they would do whatever was necessary.

Now, they do not do a eddy current inspection of the guide tube. So what they're doing

is for the thimble tube -- for the guide tube is the thimble tube will be a precursor for the guide tube because it's inside the thimble tube. It's surrounded by reactor coolant water and is just the same temperature as the inside of the guide tube. So that would be a precursor.

The small problem we had with that is that there is a weld on the outside of the guide tube between the penetration and the guide tube. And there's no any current would inspect that.

So they agreed to do so far is to do the VT-1 examination of that location at the same time they do the bottom head location. And the VT-1 would be looking for cracks. Normally this location wouldn't even be in the ISI program. So this would be an enhancement of the ISI program.

And as far as the VT-1, the ASME code specified the qualification that is necessary to ensure that you detect cracks using the VT-1.

And right now we're going through that. We haven't finished the review of it, but that's basically where they are right now.

MR. FORD: Now in the SER it talks about eddy current also. Is that no longer a monitoring technique or to be used for this particular

degradation?

MR. ELLIOT: Excuse me? What.

MR. FORD: In the SER you talk about eddy current.

MR. ELLIOT: Yes. Eddy current is going to be used on the thimble tube and the inspection of the thimble tube will be for cracking and flow induced vibration. And if any cracking is observed on any thimble tube, it will be replaced, the thimble tube. But also that would mean that the guide tube that is surrounding it would also become within inspection, and they would have to develop some kind of inspection for the guide tube at that time.

MR. FORD: Okay.

MR. ARRIGHI: Alloy 600. Again, the reactive vessel head, the control rod drive mechanisms and the penetrations were placed on the past refueling outage with Alloy 690 thermally treated penetration. The Alloy 600 components in the vessel include the bottom mounted instrument penetrations and the radial core support pads.

Barry mentioned earlier the reactive vessel internal programs. This slide is just to indicate that they have committed to submit this

program for review and approval to the staff prior to a period of extended operation.

Section 3.2, 3.3 and 3.4, those three systems resulted in one confirmatory items, and this was in the auxiliary system regarding the need to make a tech spec change to incorporate particular testing requirements for the diesel fuel oil.

MR. FORD: Now, on this particular one, they've confirmed that they were looking for particulates in the fuel oil, is that correct?

MR. ARRIGHI: I want to ask --

MR. FORD: And they're looking for exception on biocides and corrosion inhibitors.

MR. ARRIGHI: Krzystof?

MR. PARCZEWSKI: I didn't hear the question.

MR. FORD: On this confirmatory item.

MR. PARCZEWSKI: Yes?

MR. FORD: On the confirmatory item associated with the fuel oil, there's a tech spec. My understanding is that they are confirming that they will monitor for particulates, but they will not asking for an exemption on the goal requirement that you will have biocides and corrosion inhibitors. I think that's essentially the essence

of this particular AMP.

Could you give us an idea of, first of all, factually why did you agree with their statement that they do not need biocides and corrosion inhibitors? I just want your thought process.

MR. PARCZEWSKI: Well, I really don't -- I'm sorry. Repeat the question. I did not understand it.

MR. FORD: Well, maybe also the applicant can tell me if I'm stating it incorrectly.

On this issue about the corrosion of the internals of the diesel fuel oil tanks.

MR. PARCZEWSKI: Yes.

MR. FORD: They ask for an exemption from GALL in that they would not be using biocides or corrosion inhibitors. But they confirm that they would look for particulates.

Now my question here is, just for my information --

MR. PARCZEWSKI: Yes.

MR. FORD: -- what was your thought process in terms of factual data to back up their exemption request that they do not content biocides and corrosion inhibitors?

MR. PARCZEWSKI: They didn't have any MIC during their operation. So they felt they probably don't need to biocide, because the microbiological degradation during this operation period. So I felt that they're justified not to have a biocide.

MR. FORD: And corrosion inhibitor, presumably that's because of the tech spec requiring some control of the water content of the --

MR. PARCZEWSKI: Again, this is similar, you know. They didn't have any significant degradation due to corrosion. Therefore, I felt that since they have this operational experience.

MR. FORD: Okay.

MR. PARCZEWSKI: I felt that we can accept their request for not including that in their program.

MR. FORD: It just makes me feel uncomfortable a little bit that we are blindly looking to the future, as you as you said Mario, looking into the future and making judgments based on what you see today, especially for nonlinear degradation processes, time dependent processes.

MR. PARCZEWSKI: Yes.

MR. FORD: But thank you for your

answer.

MR. PARCZEWSKI: Yes.

MR. FORD: It doesn't make me feel good.

MR. WILSON: This is David Wilson from Rochester Gas & Electric.

I just can chime in that as an applicant, as a licensee we're not opposed to modifying aging management programs when they make sense. But it's important to note that adding biocides and additives to your fuel oil also have unintended consequences, just like not adding them.

MR. FORD: That's true.

MR. WILSON: So if you look in the aggregate over the industry, which we've done, and you say well what's the right thing to do at this instant? Well, the right thing to do is continue on with what's been successful, that's operating experience, trust but verify and keep looking.

MR. FORD: I accept that entirely. We are pragmatic. You've got to be pragmatic about all these things. That's the answer I would have liked to have heard. I've been asking these questions for quite some time now and that is, if you like, the correct answer. But I want some rational, technical rational.

MR. GEIKEN: Yes. This is Gerry Geiken.

We did actually investigate fairly extensively those utilities which do add biocides and corrosion inhibitors.

MR. FORD: Right.

MR. GEIKEN: And looked at their geographical distribution in the United States, and we found that they're mostly in the south. And those nuclear power plants that are in the northern climes with cooler weather have not, typically, been required or found it necessary to make those additives.

And the other part of that whole issue is, just as Dave said, we've seen that there are some other negative consequences for making these additives.

So in the sum total of our investigation, the research, we thought the best course to take is the course we're on.

MR. FORD: I'm happy that there's a quantity to judgment being made rather than we haven't seen a problem so far. Good.

Thank you.

MR. ARRIGHI: In Section 3.5, containment structures and components. There were

no open or confirmatory items identified in this section.

Aging management of in-scope inaccessible concrete. You can see from the chart here, ground water samples indicate that the below grade environment is non-aggressive at Ginna. Therefore, a plant specific program is not required by GALL.

The applicant will inspect areas when excavations allow and when aging effects on accessible portions indicate detrimental effects are occurring.

CHAIRMAN BONACA: Yes. I think they're doing the right thing of using opportunistic inspections.

What surprises me, of course, they have true non-aggressive environment. What surprises me is that we have the same requirement, essentially the opportunistic inspection also for very aggressive sites.

MR. ARRIGHI: Yes.

CHAIRMAN BONACA: That maybe it's a problem. I mean, we discuss this issue.

MR. MUNSON: Cliff Munson, civil engineering.

For aggressive sites we do more, require more than -- and Ginna is not an aggressive site, as we have established.

CHAIRMAN BONACA: Right.

MR. MUNSON: But we require that they enhance their aging management programs for aggressive sites. And I don't know if we want to get into that now.

CHAIRMAN BONACA: No, no. It's true that you have more inspections or at least inferring potential degradation from accessible locations. That's true. Okay.

MR. ARRIGHI: And the last section in aging management review Section 3, there was one open item and one confirmatory item in this area. The open item has been resolved and it had to do with thermal relaxation of the bus duct bolt connections. And the applicant has committed to perform those in sections. So that item is resolved.

And, again, there was one aging management program added as a result of staff questions.

That concludes my presentation on --

MR. FORD: I have a question on this

one, too.

In the SER it states for this particular item, 3.6.1, which was the first item, I believe, it says that there's reasonable assurance that in this case the insulting materials and antioxidants will be sufficient to not give degradation. How do you agree with the phrase "reasonable assurance?" What's your metric?

MR. ARRIGHI: I'm going to have Jim Lazevnick, the reviewer --

MR. FORD: It also appears in other areas in this SER, the words "reasonable assurance."

MR. LAZEVNICK: This is Jim Lazevnick. I'm the electrical reviewer from the electrical branch.

Yes, I think your statement is with regard to the bus duct insulation.

MR. FORD: Yes.

MR. LAZEVNICK: Internal bus duct electrical insulation.

MR. FORD: Yes.

MR. LAZEVNICK: They committed to do a visual inspection of the bus duct. Essentially consistent with other visual inspections we've approved for things cable insulation, degradation,

etcetera.

There's an industry aging management guide that deals with that and deals with the inspections. And it's on the basis that operating experience and the industry work that was done on license renewal has determined that in effect these inspections will provide reasonable assurance.

MR. FORD: Speaking just as an informed member of the public and not as an expert in this particular area, I think it might help in the SER, because I assume it's an open document, that that rational is stated. Well, and just looking on reasonable assurance as the reason for your approving. Purely perception.

MR. LAZEVNICK: Okay.

MR. FORD: Thank you.

DR. LEE: Russ, just a reminder. Earlier ACRS has a question about station blackout. Okay. So since Jim is here, can you put up the station blackout drawing?

MR. ARRIGHI: This is the applicant's diagram of the electrical components in the application.

The evaluation boundary begins at the first isolation device that's in the -- which is

right here. This green portion is the off-site power system subject to aging management review. But just upstream of the disconnect switch here and the other train, is in scope of license renewal.

And the blue portion is a 4160 portion to the safety buses.

So for station blackout, again, the boundary is at the isolation devices.

I don't know what specific questions you may have that myself or a reviewer could answer.

If there are none --

MR. ROSEN: What page are you on?

MR. ARRIGHI: Oh, this was just a handout.

MR. FORD: Yes, it was in the very beginning, I think.

MR. ARRIGHI: The licensee had a diagram, but due to time --

CHAIRMAN BONACA: They had an open item on --

MR. ROSEN: Well, I don't have it.

MR. ARRIGHI: Yes. The open item we had had to deal with this --

CHAIRMAN BONACA: The cables.

MR. ARRIGHI: -- cabling to the safety

bus. This was the bus that ties on the service water bus. Again, the cabling for the normal ESF component, safety components is in scope. And, of course, in the diesel you can power that bus and the diesels. But what we had in the open item was that-- that cabling.

CHAIRMAN BONACA: And now they're included?

MR. ARRIGHI: And that is not included. And, again, we're reviewing the response from the applicant to see if that's adequate.

CHAIRMAN BONACA: Okay. The concern is that you have is that you cannot go to cold shutdown without the --

MR. ARRIGHI: Yes, what was in that knowledge, the cold shutdown without the service water pump, correct.

CHAIRMAN BONACA: Okay.

MR. ARRIGHI: How long they could stay in that condition.

CHAIRMAN BONACA: All right. And it is still an open item. Okay.

MR. ARRIGHI: I do have a slide of that. I don't know if you want it for -- yes, the applicant had it in their handout.

MR. ROSEN: It's very hard to see in their handout. It's just blurry and fades away. You have a better slide then this, you say?

MR. ARRIGHI: No. Mine is probably the same thing as the applicant had. We had a big drawing that we had to reduce.

CHAIRMAN BONACA: The applicant has only the upper portion of that slide. Here it is. It's the upper portion.

MR. ARRIGHI: And mine is probably a reduction of the larger document. I'll give this to you to see if it's any better.

MR. ROSEN: This is substantially better, actually.

CHAIRMAN BONACA: Yes.

MR. ARRIGHI: If there's no further questions, and if you want to come back to this later, we will. If there's no further questions, I'd like to turn it over to John Rowley to discuss the time limiting aging analyses.

CHAIRMAN BONACA: Okay.

MR. ROWLEY: Good afternoon.

Section 4 dealt with time limited aging analyses, also know as TLAAs.

The applicant indicated that six TLAAs

were in accordance with criteria specified in 10 CFR 54.3. They include reactor vessel neutron embrittlement, metal fatigue, environmental qualification of electrical equipment, concrete containment of tendon pressures, containment liner plate and penetration fatigue and other plant specific TLAAs.

Section 4.2 was reactor vessel neutron embrittlement. The analysis affected by irradiation embrittlement identified as TLAAS. They were reactor vessel upper-shelf energy, pressurized thermal shock and PT curves.

Appendix G CRF 50 requires that the reactor beltline materials have sharp USE values throughout the life of the vessel less than 50 foot pounds.

As you see in the chart, screening criteria is 50, but Ginna's project to be less than 50. A foot value less than 50 is acceptable if it is determined that lower values of the USE provide marginal safety against fracture required ASME Code Appendix G.

DR. WALLIS: Could you remind us how much less than 50?

MR. ROWLEY: Well, it's projected to be

less than 50 during that period of extended operation. As of right now it's now.

DR. WALLIS: This is calculated?

MR. ROWLEY: Yes.

DR. WALLIS: Well, what's the calculated figure?

MR. ROSEN: What's the number?

MR. ELLIOT: This is Barry Elliot.

I don't know the actual number, but the calculation method is Reg Guide 1.99 Rev. 2. I don't know what number you get, but the number is not what's important. What's important is once you go below that, that you do the analyses.

Now, the analyses is a fracture fractures mechanics evaluation, elastic/plastic fracture mechanics evaluation. And that material properties for that is a J-value of fracture toughness. And that is dependent upon the cooper and the fluence. And that material property is what goes into the evaluation. It isn't the upper shelf energy. It's the fluence and the cooper that goes into the material property.

MR. ROSEN: We complimented the staff last time, I think it was on the Robinson review, when you gave this chart with the number.

MR. ELLIOT: We gave you a number of how--

MR. ROSEN: And you said that answers all the questions.

MR. ELLIOT: Okay.

MR. ROSEN: And now what you've done is left them all on the table again.

MR. ELLIOT: Well, our answer today is that there is a J-value that is function of cooper in fluence --

MR. ROSEN: Don't go through it again, Barry. We know --

MR. ELLIOT: And that's what's important.

MR. ROSEN: We know that. We just want to be shown a chart that tells us that there is 49.6 or 29.6.

MR. ELLIOT: No, it's not. It's about 42, because I know the B&W data. So above 42. I don't know how much above.

MR. ROSEN: Come back to the full Committee with the chart.

MR. ELLIOT: I feel bad.

MR. ROSEN: Ah, see here you do it.

MR. ROWLEY: Licensee is required to

calculate the -- or RT pressurized thermal shock value for each material located within the beltline of the reactor pressure vessel. The materials provide adequate protection against pressurized thermal shock events if the referenced temperature within limits. The criteria is less than 300 degree fahrenheit, and Ginna's is at 271. So they're within the criteria and the staff finds that acceptable.

DR. WALLIS: This is all calculated using a formula with fluence and all that sort of stuff in it?

MR. ROWLEY: Yes.

DR. WALLIS: What happens when the surveillance data take and they don't agree with the calculation? What do you do?

MR. ELLIOT: This is Barry Elliot.

The 271 is from the surveillance data.

DR. WALLIS: It comes from the surveillance data.

MR. ELLIOT: It comes from the surveillance date. The original evaluation from that licensee didn't have it. They just used the original, as you said, calculation using the tables cooper and the fluence. And it turns out that Ginna

is a very plant in the sense that the actual limiting material for their vessel beltline is also in their surveillance program. And so they were able to actually take the data from their surveillance program and calculate the amount of embrittlement followed the guidance in Reg Guide 1.99 Rev. 2.

That's the only open issue we have. We just have to go over that data to see that whether or not it complies with the guidance in Reg Guide 1.00 Rev. 2.

DR. WALLIS: Okay.

MR. ELLIOT: If it does, then that's the number.

DR. WALLIS: How do you get RT_{PTS} from surveillance data? You take a sample and you test it at various temperature, or what do you do with it?

MR. ELLIOT: No, no. What you do is you calculate the amount of embrittlement by the shift in the 30 foot pound transition temperature. You get it for the different capsule data for different fluences. Then fit the data for the different fluences to --

DR. WALLIS: So it's another ASME semi-curve.

MR. ELLIOT: It's not an ASME semi-curve. It's a best-fit curve.

DR. WALLIS: Okay.

MR. ELLIOT: Of the data of shifted 30 foot pound energy versus temperature of fluence.

DR. WALLIS: More like the RT_{PTS} direct.

MR. ELLIOT: And that gives you a transition temperature shift.

DR. WALLIS: Okay.

MR. ELLIOT: You take that, you add it to the initial plus to margin value and you get a total RT_{PTS} value.

MR. ROWLEY: There was one open item, and Barry just talked about that.

CHAIRMAN BONACA: So this open item really is more like confirmatory item almost. This open item is more of a confirmatory item?

MR. ELLIOT: Right. We have to just go through the data to see if all the data -- not only do they have the weld data for their vessel, but they also have correlation monitor material. We have to go to check that to see. We have certain parts of the guidance in the Reg Guide which they have to comply with.

CHAIRMAN BONACA: Okay.

MR. LEITCH: The open item in the SER says in June 10, 2003 letter the applicant changed its method of determining the referenced temperature for pressurized thermal shock. What was that change all about, or was that different than you're just describing?

MR. ELLIOT: It's just exactly what I said.

MR. LEITCH: Oh, I see. That is what you're describing.

MR. ELLIOT: They originally did it without the surveillance data.

MR. LEITCH: Okay.

MR. ELLIOT: And then they said -- in the original application it was done without surveillance data.

MR. LEITCH: Okay. I understand. Barry, I wasn't sure if this was some other change.

MR. ELLIOT: No, that was the change.

MR. LEITCH: That was the change? Okay. Thank you.

MR. ROWLEY: The applicant committed to updating their pressure/temperature curves prior to the period of extended operation. And they're going to either do that in a pressure/temperature limit

report or in technical specifications.

The applicant identified metal fatigue analysis of various components and systems as TLAAs, of which the reactor cooling system is one of them. And that's designed to a Class 1 of the ASME Code.

Design criteria for a failure of analysis of ASME Code Class 1 requires a CUF of less than one. All components at Ginna have a CUF less than one for the --

DR. WALLIS: That's the table we saw from the applicant earlier?

MR. ROWLEY: Correct.

DR. WALLIS: They were much less than one, except for one.

MR. ROWLEY: Right. Right.

And Ginna is the first applicant to have CUFs less than one, even when environmental effects are included. Just something matched with them.

There were two confirmatory items, and both were dealing with updating their UFSAR.

Environmental qualification of electrical equipment. The applicant has adequately identified the TLAA for EQ components. The EQ program's consistent with GALL. And staff concluded EQ program will continue to manage equipment in

accordance with 10 CFT 50.49 and meets 54>21(c)(1)(i)(ii) and (iii). There are no open or confirmatory items.

MR. LEITCH: As I reviewed these TLAAs, there's a whole lot of specific TLAAs for various electrical components, you know, right down to the details of a discussion of the (1)(a) and (c) ASME safety injection pump motor and (1)(b) safety injection pump motor.

And I guess I was just curious as to how these were justified for 60 years of operation. But when I looked at it, it was like so many of these things, it ended in a little bit of frustration for me. Because all it really says, well, in most cases it says it's just justified -- it's for 40 years now and by the time the 40 years is up, we'll take a look at it and see if we can extend the qualified life for replacement or refurbish it, but it doesn't really address the methodology for how this will be done, at least not so far as I can see. And it seems as though time after time here in all this qualification of electrical equipment it's another one of those things where we'll figure it out later, is basically what it's saying. Is that a fair assessment of what's going on here?

MR. ARRIGHI: WE did have a meeting with the applicant where they brought their calculation for a number of components. They were, again, I think some of them were originally calculated for 40 years and they recalculated for 60. And the staff did review those calculations.

Our reviewer right now is not here today. He's on vacation.

I don't know if George, if you remember some of the specifics and can help me out.

MR. WROBEL: Yes. George Wrobel from RG&E.

Yes. The EQ calculations that we did, we've recalculated probably 95 percent of the EQ components that are on a master list that we want to extend from 40 years to 60 years. Those calculations have all been completed. And a vast majority, I think -- well, 10 to 12 of those were reviewed by Mr. Saba during that review.

We're not putting off any of the qualification calculations. They should all be done imminently. The only ones we haven't done were a few that we feel that we will not extend to 60 years. We're going to replace those anyway.

So all the calculations have been

completed already. We're not leaving a legacy or a negative legacy here.

MR. LEITCH: So what I'm looking at here are the exceptions then? I mean, it seems like none of these are in this section, 4.4, none of these justified or qualified for 60 years. They all talk about their existing qualification for 40 years, and some cases 44 years. And it seems to say that in the future we'll decide whether that qualification can be extended or whether we have to replace or refurbish this.

MR. WROBEL: Well, we can provide -- if there's additional detail needed by the NRC, we can provide that. But there are very few calculations left that don't already go to 60 years. So the final SER should sound different than that.

MR. LEITCH: Okay.

MR. ARRIGHI: Again, the staff did review, you know, ten or twelve of those calculations, look at the methodologies and the assumptions and they were satisfied with the calculations.

MR. LEITCH: So it is not as though there is more recent information than exists in this document?

MR. ARRIGHI: And that's the SER or the application?

MR. LEITCH: This is the application.

CHAIRMAN BONACA: Application. Because the SER says --

MR. ARRIGHI: I think the SER, he specified which calculations he reviewed. I believe he went in detail and made a listing of those calculations that were reviewed, again by Saba. Again, I didn't compare them against what's in the application, though.

MR. ROWLEY: Section 4.5 concrete containment tendon prestress. Prestress losses estimated for 40 to 60 years. The applicant did provide trending analysis. And the staff considered the applicant's actions adequate during the period of extended operations and there were no open or confirmatory items.

CHAIRMAN BONACA: If I remember, they had a program to retention some of them?

MR. ROWLEY: Yes.

CHAIRMAN BONACA: There's a commitment to go to retentioning?

MR. ARRIGHI: I know they were planning on retentioning them all in 2005, I think the

remaining ones that weren't retentioned in 1980, I think. In 1980 they retentioned a 137.

I have to look at the commitment list. I don't know if that was the commitment or not.

MR. WILSON: Our commitment was to retention the remaining 23 tendons into 2005.

CHAIRMAN BONACA: I remember that.

MR. ARRIGHI: Okay. And that is the SER in Appendix A.

DR. WALLIS: Now is "adequate" a good grade or is that fairly adequate, or what's the meaning of "adequate?" Do they do more than is necessary? Do they do the bare minimum? What does "adequate" mean?

MR. ARRIGHI: Cliff Munson.

MR. MUNSON: They're required to sample 5 percent of the population of their tendons, and they do more than that. I can't remember the specific percentage, but I think it's above ten percent.

DR. WALLIS: Yes. I think, though, this is a judgment. There is a metric you and just check that they have actually met the requirements then?

MR. MUNSON: Right. Every five years they do their lift-off measurements.

MR. ARRIGHI: And again, they do three times of the requirement. I think the requirement is four percent, and they do 12 in their surveillance.

MR. ROWLEY: 4.6 is containment liner plate and penetration fatigue. The staff requested a list of the design transients and corresponding cycles that were specified in the design of the containment liner penetration. The staff finds the design transients and corresponding cycles acceptable. They conclude that the TLAAs has been projected to the end of extended period of operation. And there were no open or confirmatory items.

And there were seven other plant specific TLAAs. All demonstrated that the TLAAs have been projected to the end of the period of extended operation. Also, there were no open or confirmatory items.

MR. ARRIGHI: Well, that concludes the staff presentation, unless there are any further questions.

DR. WALLIS: It's interesting. A fly wheel is a moving part and I thought moving parts didn't appear in these renewal.

DR. LEE: Yes. This is Sam Lee. For the TLAA, the active components are also part of the TLAA.

DR. WALLIS: They are also part. Okay. Thank you.

CHAIRMAN BONACA: Okay. Do we have any additional questions for the presenters? If none, then I think what we're going to do is, would you like to take a break before we go around the table and talk about two things we have to do. One is some views by members about where we are, what we need. And also some expectations for the full Committee meeting, which is the second.

Okay. So, we can go to right now, actually, and then complete our meeting. Take a break later.

So why don't we go around the table. Starting with you, Graham, if you could give us your views?

DR. WALLIS: Well, I don't see any significant issues. These are getting so routine, these license renewal.

I do think that in terms of the presentation to the full Committee, every time you can have some numbers or some criteria, or

something, or a table, it's more convincing than saying the staff finds the work adequate, or something like that. And if you can buttress it with something quantitative or some metrics, that always is more convincing.

So, I would just suggest that.

MR. ARRIGHI: Thank you.

CHAIRMAN BONACA: Peter?

MR. FORD: I'm cautiously satisfied with disposition of all the open items and the confirmatory items. And I, again, am cautiously satisfied about the completeness of the review that's been done by the staff.

And the reason why I keep saying cautious is that I'm being asked to signed off or approve a memo which really should be based on data. And, as Graham says, we haven't seen a lot of data upon which some of these judgments are being made. And that's maybe because of time.

I'd like to see in the future as appropriate some of the analyses that has been done. And I'm going to dig into the questioning, I'm pretty sure that data does exist. It just hasn't been presented.

The one I feel I keep hitting on is

these questions of one time inspections and the opportunistic in terms of place and time and when you're going to do these one time inspections. And I think somehow or another we've got to where appropriate, and that means in the question of the consequence of the failure of these components subjected to a one time inspection, I think we have to tackle that sometime in the future.

And, again, as I've said before, it's not specific to this particular plant. It's specific to all the plants who we have been doing our LRAs on.

That's my main point.

CHAIRMAN BONACA: Yes. Well, let's talk about briefly. Because, I mean, you're talking about in the future it could be valuable for us to have an example, at least of some of the technical information behind a specific issue.

MR. FORD: Yes.

CHAIRMAN BONACA: So that the Committee will have an understanding that in fact, or a confirmation that the judgments are not based purely on some quantitative consideration, but also there is a technical basis behind that. You know, we're not party to the kind of information normally. So

it may be a good exercise for us to do. It doesn't have anything to do with this application.

MR. FORD: Exactly.

CHAIRMAN BONACA: But we may try to look for a forum. And maybe the next application that comes, start with that, we could have some specific example.

MR. FORD: Yes.

CHAIRMAN BONACA: And an example could be, for example, in a specific one time inspection. Because this has come up again frequently the concern the Committee has with the one time inspections as, you know, what they mean and why are they adequate rather than a program.

Now, I always think that the one inspection could be the springboard for a problem. What I mean is that if you expect once and you find that in fact your expectation is not supported by the inspection, then you have to respond to the program. And so I would see that coming through. But we've had a lot of questions about one time inspections.

One has been should the confirmatory of the fact that we do not expect to have something happening, and not vice versa, okay.

And that's why I asked the question about the former bolts. Because, you know, even in case you have no expectations to have a need for it, well since you did something before, it may be -- but anyway, I don't want to get back on that issue again.

So that could be helpful to this Committee if we took the next application, take one of the one time inspections and expand on it so that we can see what the logic was behind and have a better understanding of it.

MR. GILLESPIE: Yes, I think we can do that. In fact, we'll take under consideration. Because this whole thing's going to get aggravated more and more.

CHAIRMAN BONACA: Yes.

MR. GILLESPIE: As we update GALL and bring in past practice into GALL. The premise of GALL is reference GALL and keep the documentation on site.

CHAIRMAN BONACA: Yes.

MR. GILLESPIE: So two years from now you're going to probably see significantly less in an application than you even see today, which is why we've got audit teams, and we had an audit team go

to Ginna to look at the biocabinets full of background material.

So for the audit team to bring some details back on one of the audits, one of the issues. We can document it maybe in the audit report and then we'll have a record.

CHAIRMAN BONACA: Yes. And you're absolutely right. And we are diverging from a standard process of review of the SERS. For example, as I mentioned in the presentation to the Commission, where I'm looking much more at unique things about this plant that really are not addressed through GALL, but -- you know, and so if we have plant where we have a thermal shield failure with damage, I'm concerned about how to address the damage in the next 20 years: What kind of inspection and so on. So this is unique to that plant. And so we're looking for those kind of elements.

And I think we should do it in a way that doesn't penalize the licensee that comes as the next review, see if there's an example of what you've done.

MR. GILLESPIE: Yes.

CHAIRMAN BONACA: And that would be

helpful to us.

MR. GILLESPIE: Okay.

CHAIRMAN BONACA: Graham?

MR. LEITCH: Well, a couple of things. I'm a little concerned about the qualification of electrical equipment. I mean, I see in the license renewal application a lot of open issues. I see in the SER some of those are closed, apparently to the satisfaction of the staff, but not all of them.

Now, I'm not sure if I'm just talking about a timing issue here. In other words, maybe they are more closed now and it'll become apparent in the final SER just what the status of those is, but I'm just not sure about that.

But I see, for example, safety injection pump motors and I see a list in the SER of calculations that have been reviewed. But the safety ejection pump motor EQ is not among those calculations that have been reviewed.

Now I don't know. Perhaps in the month or so since this has been written that's in progress. I just don't know that. But I just think that what we're saying here or what the license renewal application seems to be saying is we'll worry about that in the future. And I think that

issue, perhaps, could be resolved now.

MR. GILLESPIE: Yes. I think the disconnect that you heard was that the licensee in parallel with having submitted the application was doing these calculations. And we reviewed illustrative applications of his process, but we didn't review every single one of them. And you're not going to see a one-to-one correspondence between the applicant's chart on his submittal in the SE. So those are illustrative reviews in the SE.

MR. LEITCH: So it's to gain confidence in the methodology, not necessarily a --

MR. GILLESPIE: Not a 100 percent confirmation of each component.

MR. JACKSON: Do you mind if I make a comment on this? This is Jarred Jackson from Ginna.

The basic process environmental qualification is such that you replace the component when you reach the limit that was previously analyzed. That's actually the most conservative state that you could be in.

So if we get to a situation where we're saying we're not analyzing it right now, we're in the conservative state that the EQ rule is already going to replace that component.

So in some of these instances that you're bringing up, we may actually be more conservative than we need to be for license renewal. At any point in the future we may redo that analysis such that we say the temperatures are lower or not as much irradiation in the field. And those are the types of data that comes into consideration for these analysis.

MR. LEITCH: Yes. Okay. That's a good explanation.

I guess the other more general issue I had was related to this issue that was mentioned on the first couple slides regarding the sale of the plant. I don't know what the NRC's position would be if that is in some kind of progress at the time that this license renewal application is becoming final. In other words, are we dealing with Rochester Gas & Electric here or are we dealing with the new people, whoever they may be. It seems to me it would need to be one or the other, but not crossing over someplace in midstream here. Maybe that's not a safety issue, it's a legal financial kind of an issue. But I just wonder how we would deal with that.

MR. MECREDY: It's Bob Mecredy from

RG&E.

In fact, license renewal will be done by RG&E because the plant sale is contingent upon a renewed license.

MR. LEITCH: Oh, okay.

MR. MECREDY: So license renewal is first and then transfer. It makes sense. The new owner, they're interested in 20 some odd years, not 2009.

MR. LEITCH: Sure.

MR. MECREDY: So that's the basis for the sale.

MR. LEITCH: Yes, okay. Well, that answers that question.

MR. ROSEN: And, Graham, the new owner will have to meet all the certain tests for financial resources and other things.

MR. LEITCH: Right. Understand that.

MR. ROSEN: In order to be able to accept the new license.

MR. LEITCH: Yes, I understand that.

MR. MECREDY: Yes, that's right.

MR. ROSEN: And it makes logical sense, and it's a two step process.

CHAIRMAN BONACA: I think it's a good

question. Because I mean, that owner, I mean so much of this -- this is a promise of maintaining this plant to this level. And I think, actually, that there are a lot of good commitments from this plant. I mean, you know the commitment to replace the head at this time, I think is a proactive one. And so there'll be a new owner, they may think differently.

So, but I agree with you that --

MR. ROSEN: The new owner did come in and say, "Yes, well that was the other guy. That wasn't us."

CHAIRMAN BONACA: Well, you may see that.

MR. LEITCH: Well, I think as long as it's one side or the other and it's been explained this will be done before the transfer the ownership--

CHAIRMAN BONACA: Yes, I agree.

MR. LEITCH: -- as long as that's clean, I don't have any problem with that.

CHAIRMAN BONACA: Yes. I agree. I agree.

MR. ROSEN: The new owner has to come in and has to accept all the previous commitments of

the licensee?

CHAIRMAN BONACA: I agree. Right. I agree.

MR. ROSEN: It's just a new licensee for the old commitments.

MR. LEITCH: Yes, and there's no question about that. It's just that if this process was someplace midstream when that ownership was transferred, it could be somewhat confusing. And that's what was concerning me. But we're hearing that that will not be the case.

I don't know if you wanted us to talk a little bit about points to be emphasized at the full Committee meeting.

CHAIRMAN BONACA: Yes. Yes.

MR. LEITCH: And one of the things that I think is important in that context is the management of these commitments. And I guess RG&E may be in a little awkward position to defend exactly how these commitments will be managed with this transfer of ownership in the offing.

But I guess the thing that I would like to hear addressed more is there are a number of places here where there are future commitments. And how are those commitments going to be tracked? Is

there an on-site organization that's going to track these commitments? As plant modifications over the years, how does that all factor into the license renewal program? And just how is this going to continue to be a dynamic process until the period of extended operation is entered?

And I don't know if you can shed any light on that at the full Committee meeting or now. And it may be a somewhat difficult situation because of the change of ownership.

MR. MECREDY: This is Bob Mecredy again.

We can address that. George will address that at the full Committee. But fundamentally it's the same process we use now to address commitments we have made in the past for things we have had to do subsequently or things that may still need to be done between now and the end of the current license. So the process for managing commitments is really just a case of how far in the future as opposed to anything that's different. And certainly commitments we have made in the past remain commitments regardless of change in licensee, unless the new owner decides to come back to the staff and change the commitments. There's a standard process for that -- but we will talk about

commitments and how we manage them. And we do have a system and a process on-site that tracks commitments and ensures that they're done, and there's various categories with MRP and our sequence being at the top of the list. And that is actively managed in accordance with our practices and industry standards. So we can talk about.

MR. LEITCH: What concerns me is not so much changing the commitments as assuring somehow what is the process for assuring that the commitments will be tracked and completed by the time of entrance into the period of extended operation.

MR. MECREDY: We'll address that.

MR. GILLESPIE: Graham, just from our side since they're making up the list and we have to check it, the majority of things like participating in the MRP program and those things are in the FSAR. So that you've got as a minimum once a new license is issued, a 50/59 type control on the FSAR. So there's a safety level -- it redefines the safety level for the operating facility once they get the new license.

The other thing is we have a custom inspection procedure for each plant that's written

based on that commitment list, which the staff is then maintaining which will get inspected before the end of the term. And so that's being done for every single plant.

So you've got the FSAR list, there's other things, and then you've got a specific inspection procedure for each plant. And this actually came out of earlier ACRS staff discussions on how are you keeping up with the list. So there's a bit of formality in it. And the industry overall agreed to put these in the FSARs, which previously they did not do. So the first couple of plants didn't necessarily have that.

MR. LEITCH: Yes. I guess what I'd like to hear a little more about how the licensee plans to manage that.

MR. GILLESPIE: Yes.

MR. LEITCH: I mean, I know what you're doing. But I guess there have been some licensees that have come and told us basically that plant license renewal is just integrated into their normal process of doing business. Others have seemed to indicate that they kind of have a permanent license renewal organization that manages all these things and assures that they get done.

And I guess I'd just like to hear a little discussion about how Rochester Gas & Electric plans to do that. And I guess their plans, the method by which they manage these things are probably not hard and fast commitments. I mean the commitments are hard and fast, but the method they use to manage them are so that they have some latitude there.

MR. GILLESPIE: Yes.

MR. LEITCH: And perhaps the new owner may see it a little differently than Rochester Gas and Electric. But at least I'd like to hear how Rochester Gas & Electric --

MR. GILLESPIE: Yes. The danger here is that the onus is now shifted once the license issued. The onus is kind of shifted to the staff to confirm it.

MR. LEITCH: Yes.

MR. GILLESPIE: And if a commitment is not met, then now we're into the compliance arena relative to any actions we're going to take because the license is gone.

MR. LEITCH: Right.

MR. GILLESPIE: So there's a kind of shift of burden once we issue that license.

MR. LEITCH: Yes. Yes.

MR. MECREDY: Bob Mecredy again.

I would argue also that it's our commitment and it's our obligation to meet it, so we still have even with the new license, an extended period, it's still our nickel and we're obligated to do it. Staff has the role of inspecting to assure we've done it, but it's really no different, again, than any other commitment we've ever made. Once we've made the commitment, we're obligated to do it as part of our license where it's part of our normal correspondence with the staff.

MR. LEITCH: Yes.

CHAIRMAN BONACA: Any other issues?

MR. ROSEN: The difference is the magnitude, Bob. The magnitude of the number of commitments and the length of time over which they are operable. You know, it's a question of degree more than anything else.

CHAIRMAN BONACA: Steve, your views?

MR. ROSEN: Well, I thought this was a very well done application and I have only two questions that remain. One is a commitment I made earlier, I'll just reenforce it.

When you come back to the full

Committee, I really would like to reactor vessel upper shelf energy chart revised to show the value, just like the pressurized thermal shock chart that shows the value.

And then I'd like to take you back to a question on the station blackout diagram. Can you put that back up again?

Now, there was a question, an open item that staff had identified that there were two cables from the off-site power path that bring power into the safety buses that were not in scope.

MR. ARRIGHI: Yes.

MR. ROSEN: Now, are they now in scope?

MR. ARRIGHI: No. The applicant's position is that these two cables that power the --

MR. ROSEN: Which two are they?

MR. ARRIGHI: These outer two cables here. Those two cables, their statement is that they don't need to power the service water pumps because they can get a cold shutdown within 72 hours without those. That's their CLB.

CHAIRMAN BONACA: Without what?

MR. ARRIGHI: Without the service water pumps.

CHAIRMAN BONACA: Without the service

water pump.

MR. ARRIGHI: And those cables supply the service water. This bus supplies the service water pump.

MR. ROSEN: And the way they will do that is by feed and bleed of the secondary side into the containment?

MR. ARRIGHI: Correct. Yes, they would use the standby aux feedwater or the aux feedwater pumps to --

MR. ROSEN: To keep the speed of the steam --

MR. ARRIGHI: -- feed the steam generators and then dump steam --

MR. ROSEN: This is in station blackout now, right?

MR. ARRIGHI: Yes.

MR. ROSEN: We're talking about station blackout conditions where they have steam but no power.

CHAIRMAN BONACA: Yes, and they -- I'm sorry.

MR. ROSEN: The DC power supplies to control the turbine driven aux feed pump, refilling the steam generators with the steam that the steam

generators are providing as the steam pressure decays, and dumping water on the floor through manual valve into the containment?

MR. ARRIGHI: Correct.

MR. ROSEN: And they've got volunteers for this?

MR. WROBEL: Mr. Rosen, we've mixed up to licensing conditions here.

MR. ROSEN: Okay. Help me unmix them.

MR. WROBEL: Okay. Forgive me for this if I contributed to it.

With respect to the 4160 volt cables going to the buses, should they be lost on a station blackout event, that's one condition. It's different than the fire condition that we were talking about earlier for the water solid steam generator cool down, although there are issues with respect to a fire in the screen house that might drive you to a water solid steam generator cool down. It's more than loss of just these cables.

So the cable itself here, you are correct in assuming that on a station blackout I have lots of stored energy in my steam generators that I'm going to use to run my turbine drive auxiliary feedwater pump. And in order to refill my

water source for the turbine driven aux feedwater pump, I may elect to use my fire water system to add water to my storage tanks.

MR. ROSEN: And you can do that because it has a diesel driven fire pump?

MR. WROBEL: I can do that because it's a diesel driven fire pump. So that's one of the issues.

The other --

MR. ROSEN: That's one issue. Now I know how you're going to get sustained water into the secondary side of the steam generators. Now, how are you going to --

MR. WROBEL: That's not a feed and bleed.

MR. ROSEN: -- get steam to the feed pumps.

MR. WROBEL: That's not feed and bleed. That particular evolution is normal cool down in a station blackout using turbine driven aux feed water.

MR. ROSEN: And diesel fire pump.

MR. WROBEL: And diesel fire pump.

MR. ROSEN: You were telling me?

MR. WROBEL: The feed and bleed

evolution is an evolution that would occur if we lost service water for the component cooling water system, the ultimate heat sink, so to speak. So I can run on an accident. I can run my diesel driven or my emergency diesel generators without service water. And I do that by virtue of hooking them up to fire water systems; that's one of those SOP topics. So I don't need service water in order to immediately mitigate the consequences of the event, but long term if I want to go to long term cool down, because I don't want to stay in hot shutdown, I want to drive myself to cold shutdown --

MR. ROSEN: In a station blackout. No.

MR. WROBEL: In a fire event.

MR. ROSEN: In a fire, not a station blackout where you have the diesels running to give you power, on-site power --

MR. WROBEL: I still don't need service water because I can use this water solid steam generator cool down method, thereby avoiding the necessity of having component cooling water for RHR system, which would be normally feed from the service water which is lost because of fire.

CHAIRMAN BONACA: See, one thing that concerns me about, and maybe I'm wrong but I want to

bring up, some of this, you know, not orthodox ways of providing for cooling, etcetera, seems to be coming from the SEP. Okay. In the SEP you -- now that was really a program that was tailored for plants that were supposed to operate 40 years and did not meet the design basis or requirements of the SRP, therefore you allow for, let's say, unorthodox ways of dealing with these issues.

Now you're using it to justify 20 more years of operation. I am not sure that logically there it's satisfying to me. I just throw it on the table.

MR. ARRIGHI: Again, we do have the open item on this issue and we're still evaluating it.

MR. ROSEN: Is there more to be said or is that the whole story?

MR. WROBEL: In a fire evolution where you would use the water solid steam generator cool down method, the turbine drive auxiliary feed water pump is not the water source. It's the standby auxiliary feed water pump. Those additional two pumps that we installed and talked about earlier today, that's the water source that puts the water into the secondary system. Those two are fed from the city water system, if necessary.

If you lose service water, we have two places that you can hook up the fire loop. One is the emergency diesel generators, the other to the suction of the standby auxiliary feed water pumps.

So what we've somehow mixed up here today is two events; the station blackout and a fire event.

MR. ROSEN: Station blackout is that event where you --

MR. WROBEL: Station blackout --

MR. ROSEN: -- lose all the power on that system right there.

MR. WROBEL: Correct. Where I lost my essentially service water.

MR. ROSEN: Yes.

MR. WROBEL: And now I run my -- initially I'm running my decayed heat removal via my turbine driven auxiliary feed water pump. And then as a remake or a refill capacity for my turbine driven auxiliary feed water pump, I use fire water from the diesel driven fire pump and I have an inventory source at that point.

MR. ROSEN: And that's the justification for not including those two lines in the scope of license renewal?

MR. WROBEL: That's part of the justification.

MR. ROSEN: What's the down side of including them in? Anything? Or is this just an argument, what we used to call academic arguments here, but we have a highly influential persons who are in the academics sphere here. And we don't call them academic arguments, because that's the pejorative term.

MR. WROBEL: In essence, this is just a discussion for the staff over the breadth and the scope of our current licensing basis and where it starts and stops.

MR. ROSEN: Okay. So if you are of a mind to, you could say it's not in our current licensing basis but we could include -- we will include these in our license renewal anyway? You could say that? I mean, that would clarify it?

MR. WROBEL: Yes. Yes, sir, we could say that.

CHAIRMAN BONACA: Other licensees that don't say things of that kind.

MR. ROSEN: Well, I would suggest that you try somehow for the full Committee to make this clearer. Because even though I've listened to the

whole argument, I still am -- it' the fog of war, maybe. But I don't understand it exactly, and you know I have I some experience in this area.

CHAIRMAN BONACA: And, again, you know, I love to point out what I did not like, and I didn't hear an answer to that. But they're using some unorthodox ways by SRP that are being allowed for your plant because you did not meet the SRP requirements to continue to justify certain unorthodox ways of getting to cold shutdown to exclude components from scope. And I say, yes, it's consistent with your licensing basis. But, you know, what if the plan now goes to 60 years of life, then it goes to 80 years of life. You know, I just feel less comfortable with that. And my concern is that you know the intent of the SEP was not one -- it was a grandfathering of older plants to keep them running for the 40 years of operation.

Now, I'm not saying that you're not justified to go to 60, but I feel uncomfortable. I got to think about this.

MR. JACKSON: I'd like to comment on that for a moment. This is Jarred Jackson.

Part of what we're talking about here is recovery from a station blackout. I'm sure you guys

have heard this discussion before.

CHAIRMAN BONACA: Sure.

MR. JACKSON: And the industry may have interrupted recovery different, understanding what the licensing basis for coping versus recovery. So as an industry, we did not have or did not feel we had recovery as a licensing basis issue. So when the staff had interpreted it in that way such that we are now addressing recovery, we looked at the CLB as a whole. So I don't want to misimpression as if this is an orthodox methodology, because it's also a differing opinion on interpretation of the CLB.

So, it's not as if this is very clear cut in the CLB and we're using an unorthodox method of achieving it. You know, we acknowledged the staff's understanding of recovery, and we've attempted to address it and in a manner that I think we both agree on.

CHAIRMAN BONACA: I'm saying, however, that most people to recovery station blackout, they want to use their service water. And that's what we have seen from other people; they have to recovery water or use it. And here you have an exception from recovery service water based on, I call it unorthodox when you tie fire water to the

secondaries and you keep generating steam for your steam driven pumps by pumping fire water in a steam generator.

MR. ROSEN: And draining by manual valves into the containment.

CHAIRMAN BONACA: That's right. Into the containment. I mean, you know --

MR. ROSEN: Is that what I heard?

MR. WILSON: Dave Wilson, Rochester Gas & Electric.

But the draining actually happens via some connections into the yard. So you steam via the normal method until you get steam pressure. So you're steaming through the atmospheric relief valves, main steam atmospheric relief valves. And then when you get to a certain condition, you can't get enough steam pressure, then you shift over to adding water to the secondary side and draining that water out, basically using a steam generator as a heat exchanger, you know water-to-water heat exchanger --

MR. ROSEN: Now this is a steam generator that has no tube leaks, I hope, because you're not draining --

MR. WILSON: That is correct, sir.

MR. ROSEN: -- radioactive material to the yard.

MR. WILSON: No tube leaks.

MR. ROSEN: You have the new steam generators.

MR. WILSON: Right.

MR. ROSEN: Are they made of impervium?

MR. WILSON: They're not made of impervium, but our licensing basis doesn't account for having, you know, significant number of beyond design basis events or unusual things happening at the same time.

MR. ROSEN: Well, this whole thing is rather curious is all I have. Mario calls them unorthodox. He has used more stronger words in the past. But I'll stay with that.

MR. WILSON: We're quite capable, I think, the full Committee of making a nice presentation on this issue and/or if we don't decide before that point, just put the cables into scope.

MR. ROSEN: Okay.

DR. WALLIS: Yes. That would be the simplest thing to do.

MR. WILSON: It's appearing to be that.

CHAIRMAN BONACA: Any other issues?

Steve?

MR. GILLESPIE: That's all.

CHAIRMAN BONACA: Okay.

Insofar as my views, first of all what I think of the application. I think that it was a very clear application insofar as the documentation. I thought it was well organized. I mean, I could follow from table-to-table clearly.

So, I thought more highly of GALL after reviewing this.

I think that I'm impressed by the way that some of the specific commitments have been implemented. I commented on the auxiliary feed water system. I've seen other SEP plants that did not go that far, and so that seems to me like a serious commitment of the station in the past and present to improvements to the plant.

And I've been impressed by the quality of the replacements in generators and then the head being ordered now and implemented in 2003, although you have no obvious leakage from the head. So there is, again, I am sure that was driven also by your intent of selling the plant, but whatever reason it may be, it meant enough, and it's even better.

So that was significant to me.

With regard to the presentations to the full Committee, I think it would be helpful after you have the Systematic Evaluation Program, since most people are aware of that, if you could highlight in your slide the major issues. You know, you had off feed. You may have some others that you want to point out.

You do have this bleed and feed on the secondary side, which I have never seen by any plant except in Germany where they use it as a standard way of bleeding and feeding rather than the primary side. So that was interesting. I haven't seen it here. So, you may want to point out some descriptions. Because it was difficult a little bit for a reviewer to understand exactly how the plant is configured, and we did not have the benefit of a FSAR in front of us to look at those features.

And I think that pretty much I just don't have any additional comments really here. I think many of them have been by my colleagues here.

So for the full Committee, I think we should have some clarification of the SEP, as we said. And otherwise I think that the representation was good. I think you'll have to collapse it down. We have much less time than we have at the

Subcommittee meeting.

MR. ROSEN: Short one side.

CHAIRMAN BONACA: What?

MR. ROSEN: We need one revised slide.

CHAIRMAN BONACA: Yes, we need revised slide with some quantitative information.

But insofar again at the next renewal, I think we should have an example of a quantitative, for example a decision on time inspection that will give us some comfort insofar as --

MR. GILLESPIE: I think the next one on the schedule is Summer.

CHAIRMAN BONACA: Summer.

MR. GILLESPIE: And Summer has no open items right now. And we're not on a schedule for about 3 months. So we'll come with one example so we'll have something to talk about.

CHAIRMAN BONACA: Okay. I don't have any other comments on that.

So are there any other comments or questions from the members? Any questions or comments from the public? If not, then the meeting is adjourned.

Thank you very much.

(Whereupon, at 4:23 p.m. the meeting was adjourned.)