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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,

MAY 31, 2005

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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

THOMAS S. KRESS, Member

GRAHAM M. LEITCH, Consultant

STEPHEN L. ROSEN, Member

WILLIAM J. SHACK, Member

JOHN D. SIEBER, Member

GRAHAM B. WALLIS, Member

ACRS STAFF PRESENT:

JOHN G. LAMB

CAYATANO SANTOS

NRC STAFF PRESENT:

KENNETH CHANG, NRR

KURT COZENS, NRR

GREG GALLETTI, NRR

FRANK GILLESPIE, NRR

MARK HARTZMAN, NRR

SAMPSON LEE, NRR

PATRICK LOUDEN, Region III

PATRICIA LOUGHEED, Region III

MICHAEL MORGAN, NRR

NEIL RAY, NRR

VERONICA RODRIGUEZ, NRR

GREGORY F. SUBER, NRR

PRESENT FROM NUCLEAR MANAGEMENT COMPANY:

BRAD FROMM

BILL HERRMAN

DOUG JOHNSON

TODD MIELKE

MARK ORTMAYER

STEVE SCHELLIN

JIM SCHWEITZER

JOHN THORGERSEN

A-G-E-N-D-A

Opening Remarks
Chairman Bonaca 4
Staff Introduction
Mr. Gillespie 7
Point Beach Red Inspection Findings
Mr. Louden 12
Poing Beach License Renewal Application
Mr. Johnson 57
Overview, Mr. Knorr 59
SER Overview by Veronica Rodriguez, NRR
Scoping and Screening Methodology Results . . . 122
Aging Management Program Review and
Audits, Kurt Cozens, NRR 143
Onsite Inspection Results
Patricia Lougheed, Region III 161
Time Limited Aging Analyses by
Gregory Suber, NRR 186
Subcommittee Discussion, Mario Bonaca, ACRS . . 214

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

12:30 p.m.

CHAIRMAN BONACA: This meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Plant License Renewal Subcommittee.

The ACRS members in attendance are Steven Rosen, John Sieber, William Shack, Graham Wallace and Dr. Kress. ACRS Consultant Graham Leitch is also present.

Cayatano Santos of the ACRS staff is the designated Federal official for this meeting. Also, Mr. Jim Lamb with the ACRS staff is in attendance to provide technical support.

The purpose of this meeting is to discuss the license renewal application for Point Beach Units 1 and 2. We will hear presentation from representative of the Office of Nuclear Reactor Regulation, Region III Office and the Nuclear Management Company.

The Subcommittee will gather information and relies relevant issues and fact, and formulate proposed positions and actions as appropriate for deliberate by the full Committee.

The rules of participation in today's

meeting have been announced as part of the notice of this meeting previously published in the *Federal Register*.

We have received no written comments or requests for time to make 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. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the Subcommittee. The participants will first identify themselves and speak with sufficient clarity and volume so that they be readily heard.

We will now proceed with the meeting.

Before I turn the meeting to Mr. Gillespie of the staff, I would like to just make a statement regarding the agenda.

As you can see in the first portion of the meeting until 1:40 we are scheduled to review the Point Beach Red Inspection Findings. The Committee has adequate information regarding these findings, and I want to make a statement about this.

The Committee is fully aware that the license renewal rule deals with future action and the

programs necessary to support the plant operation during that future action. And we realize that some of the current performance issues are being dealt with the current license basis. So we're not really concerned about old issues that came from the inspections, but those that related to specific issues, one is human performance and the second one is corrective action program.

The reason why we are asking questions about those is because we have now experience with license renewal and we have seen the corrective action programs as really the foundation to license renewal. Every program that is in license renewal moves right through the corrective action program, either in the identification of aging degradation or in the resolution of it. So license renewal is fundamental to it, and we are interested in knowing the condition of this corrective action program.

We're also concerned about human performance because thousands of commitments are being made here, and only a portion of those are being audited by the staff. And so the question we have to ourself is what's the quality of the implementation of these commitments, what is the quality of the future implementation of these commitments. And so it's a

narrow questioning of performance, but it addresses these two specific areas.

With that, after we cover that area, we will move into the normal process of the ACRS reviewing programs and management activities.

With that clarification, I'll turn it over to Mr. Gillespie.

MR. GILLESPIE: Thank you, Mario.

I know we've had this issue before and the staff wrestles with it itself continuously of trying to separate implementation from the licensing effort of renewal. But we feel that the rule is pretty clear in 54.30, as Mario said. And so this is a difficult issue. And we've generally tried to be very cautious of not mixing current performance and license renewal together. And I do agree that the corrective action program is key to renewal, and that's where the commitments are kept. And so it's a difficult threshold to wrestle with. And in general, the way the staff really has to deal with it and rationalize how we find this acceptable, is that the regions have responsibility, and I think in Point Beach's case, the region's involvement in the day-to-day program and highlighting issues day-to-day is what we are fully dependent upon as opposed to mixing that with the

licensing activity, which is really looking at processes and procedures so that there's a difference between structure and implementation.

And as part of license renewal we're looking at structure. And in the regions they're looking at implementation.

It is a difficult line. I understand the Committee's interest in it. But the staff is really obligated to follow the rule itself, and that's what we're going to be doing. And this is highlighted by the kind of outside interface. And I don't know if anybody here knows it, but Legislator Spano from Westchester County wrote us a letter saying he understood this difference. And it was petition for rulemaking to actually change the rule to cause current operations to have ann influence on this decision.

So, again, to the staff it's a threshold we do try to maintain. And I'd appreciate the indulgence of the Committee in anyway that if you could appreciate what the staff is trying to do, and our dependence upon the regions for the day-to-day oversight so that we don't condition one thing with the other.

CHAIRMAN BONACA: Yes. Let me just be

clear. That I don't think the Committee concern, if I can voice at this stage we haven't had a meeting, is to do with past/non-pass issue. It has to do with the credibility at this time of the programs. Okay. And so that's why we want additional clarification to understand that in fact it can rely on these programs, and also to -- you may, for example, have taken actions like granted inspections that give you further comfort that human issues, human performance issues have not affected the quality of the commitment.

Now that certainly would be an element that would be interesting to the Committee. It would enforce -- so that kind of thing.

I would like to also state that the same issues are of concern to the whole Committee, that's why we asked you to come tomorrow and bring the same views.

MR. GILLESPIE: Right.

CHAIRMAN BONACA: And we have only one hour, I believe, 1 hour and 50 minutes tomorrow, but that will be the focus.

MR. GILLESPIE: So Pat Louden is ready to go over from Region III the current operational situation as the region sees it. But, again, if we need a special inspection for some reason for human

performance or corrective action, the staff generally sees that in line with current operations. And that's a fair comment to say that when this CAL is lifted, you know should we have something that kind of crowns the whole thing where we go in and take an interval look. Fair comment, but I connect that with the CAL and the current license, not necessarily with the renewed license. But that's the staff's connection versus the Committee's.

So, we look forward to your comments and anything that we can answer, we will.

And I think I asked, Mario, we do have the right people here to talk about PTS. And I will highlight this is a unique facility in that it's the first one that might inflict what I'll call the EDO memo, where we kind of laid out that the PTS rule is the only rule that has an automatic shutdown in it. But the technical aspects the staff will be prepared to answer detailed questions, because you might not have gotten enough detail in the package.

CHAIRMAN BONACA: Yes. I believe I voiced for all the members that first of all, we got the submittal and the SER discussion and then there was a dependency on the master curve.

MR. GILLESPIE: Right.

CHAIRMAN BONACA: And there is a further commitment to manage aging of the vessel. So it's not clear, I believe, to most of the members of the Committee what path we're following there. And also we need some tutorial from maybe Mr. Elliot, if he's there, on how each one of these paths can take us to end of life.

MR. GILLESPIE: Yes. I think this is one of the more unique ones in end of life under current rules is coming so soon, particularly I think for Unit 2.

CHAIRMAN BONACA: Yes.

MR. GILLESPIE: And so this is a good one to get this technical issue on the table to see what should the interval story look like versus maybe it looks a bit piecemealish right now. So, hopefully, the staff and the licensee can clear that up today and do whatever they can. Because this will set the tone. Because undoubtedly there's going to be some more.

Beaver Valley when it comes in, is in a similar situation. I think we have four sites that have similar issues. So this will give us an opportunity to understand what's the best way to demonstrate or lay out the technical aspects.

CHAIRMAN BONACA: Yes.

MR. GILLESPIE: With that, let me turn it over to Pat from Region III.

MR. LOUDEN: Okay. Thank you, Frank.

Good afternoon.

My name is Pat Louden. I'm a branch chief in Region III in the Division of Reactor Projects. My main responsibility is supervisory oversight at the Point Beach site for the Part 50 ROP.

My presentation I have for today will go over a brief background of the red findings, some actions taken by the region as far as inspection actions. And I believe I've scoped it into the two areas that you have an interest in, with the human performance and the state of the corrective action program to give you an update assessment of where we see those programs.

The first slide is a background. During a licensee's PRA upgrade in 2001, the licensee identified a common mode of failure vulnerability with the auxiliary feedwater system. This was raised to us in November of 2001. The region responded by conducting a special inspection to review the circumstances surrounding and the considerations involved with the discovery of the findings. And we preliminarily issued a red finding in the spring of

2002. And the final red was issued in July of 2002.

The licensee had requested one of the considerations through Manual Chapter 0305 was that for certain issues could be considered as an old design issue, and there are certain set of criteria that a finding would have to meet to qualify for that. Because of that we conducted a follow-up inspection later in 2002. And it was during as we were evaluating the results of that inspection when the licensee during post-maintenance testing, I believe it was, on the auxiliary feedwater system identified what became eventually the second red issue.

DR WALLIS: Can I ask you something here?

MR. LOUDEN: Yes, sir.

DR WALLIS: You found something here which was presumably disturbing enough to issue a red finding. What is the fix for this? What is the corrective action as a result of this discovery of these problems?

MR. LOUDEN: Well, I'll briefly go over the immediate corrective actions, the corrective actions that the licensee took had to deal with addressing procedures and operator training.

DR WALLIS: And shouldn't that make the finding go away or does it just -- what would be

required to make the red go away?

MR. LOUDEN: Per 0305 we can leave the finding open until we feel that the root causes or the causes that affected or caused the event have been satisfactorily answered. Part of the problem with the first finding we identified was the corrective action piece of it and with procedures. And it's the corrective action program, the corrective action piece that we are continuing to evaluate fully for the licensee--

DR WALLIS: I think what's puzzling me is why it wasn't fixed when it was something that clearly has to be done? Why is taking some time?

MR. LOUDEN: Okay. The --

DR WALLIS: The problem is still there, is it?

MR. LOUDEN: Not with regard to the operability of the system. There's still the programmatic issues that we're evaluating for the corrective action program.

CHAIRMAN BONACA: Or the actions to prevent reoccurrence, I mean, also.

MR. LOUDEN: Correct.

CHAIRMAN BONACA: And the correct --

MR. LOUDEN: They're specific for that

given problem. We're evaluating broadly the whole corrective action program.

MR. ROSEN: So when were the specific technical fixes made to the first problem? When did the licensee complete those?

MR. LOUDEN: They completed those, I believe -- I don't want to defer that specific to the licensee. If Mr. Schweitzer would like to address that, the engineering director.

MR. SCHWEITZER: Well, the first technical fixes that were done -- and this is Jim Schweitzer, I'm the Director of Engineering at Point Beach.

Some of the initial technical fixes that we needed to do was associated with procedures for the operators so that they knew and took the proper action and did not reduce aux feedwater flow to the point where there was not adequate flow because of the recirc valve.

They did physical changes to replace the orifices. And those were replaced in 2002 and 2003. I think March 2003 we finished the replacement of the orifices.

We also did some changes to the aux feedwater recirc valves to change the power supplies and to make them safety related and change the safety

related function to open. And that was completed in 2004, early 2004.

So the physical changes to address the issue are done. The longer term issues that Pat was talking about are associated with some of our design control and the way we handle design to make sure we do adequate reviews. And those were processes that we have put in place. Special processes for review of the modification. We established what we call our Design Review Board which gets all of the different departments involved in the reviews so that we do a much more detailed review.

Another corrective action that we identified as part of this was our independent reviews that were done of the designs were not always adequate. WE established a separate independent review department in order to do that.

So a number of the actions are in place. The physical changes are done. The longer term program and process items are in place, but they're still being reviewed to make sure that they're going to be sustainable for going forward.

MR. ROSEN: But the initial changes that were done that made the aux feedwater system operable again were operational procedural changes, is that

correct?

MR. SCHWEITZER: Yes. The very first things we put in place --

MR. ROSEN: Because basically I think you said to direct the operators not to reduce the throttle feedwater back so far that they had to rely on the recirculation.

MR. SCHWEITZER: That was the initial changes that we put in place, correct.

MR. ROSEN: And those were done when?

MR. SCHWEITZER: Those were done when the issue was identified? Immediately.

MR. ROSEN: You mean that day or immediately?

MR. SCHWEITZER: Within weeks. I don't remember the exact time, but it was essentially immediately to establish the operability.

MR. ROSEN: Okay.

MR. LEITCH: I think the issue here is that there were several opportunities prior to the fixing of the problem. Several opportunities to perhaps identify the problem that were not taken advantage of. And so that the point is it's not specific to this particular technical area, but the fact that some of these other opportunities to

identify and solve the problem were missed gave rise to some of the questions that we see surfaced in the CAL, things like human performance, engineering operating interface, corrective action program and so forth.

So those things, I believe, opened up a wider area of programs than the specifics of this particular issue. And I think that's the thing. I think the specifics of this particular issue were quickly solved. I don't think that's really the issue. I think the issue is what are the more systematic problems that exist at this site.

MR. LOUDEN: The second red issue that was -- as we did the inspection when the plugging of the orifice issue came up, that is when we identified the design control type issues associated with the modifications. We also identified at that time that the first issue would not be a candidate for old design issue credit, because there were indications of current performance problems at the time.

It was in 2003 in the cover letter to the inspection report from that inspection that we notified the licensee that the first issue would be considered red and they would be placed in column four of the action matrix. And it was following the 2003

agency action review meeting in a subsequent letter that we notified them that we'd be conducting a 950003 supplemental inspection.

Go to the next slide.

The 950003 supplemental inspection is diagnostic in nature and it helps us focus on particular issues that we know whether or program has performance deficiencies, to better understand the depth and breadth of them. We also looked into areas that we were not that apparent, given the one individual issue, to find out if there were other areas that may be of interest to us. The one most noteworthy of the five that we've covered in the CAL is the emergency preparedness program. That is where we had known performance questions. We explored it further during the 95003 as we did the Appendix A for that procedure, which looks deeply into the emergency preparedness program. And it was there were we identified additional areas of concern within the EP group at that time.

MR. LEITCH: What was the color of that emergency preparedness finding?

MR. LOUDEN: Yes. There was a white PI, I believe it was --

MR. LEITCH: PI, but what about the

violation?

MR. LOUDEN: Well, the violations that we identified during as outcome of the 95003 review, is that what you're asking, sir?

MR. LEITCH: I think so, yes.

MR. LOUDEN: There were three -- I believe I have the number right -- three green findings. There was one unresolved item that had to deal with changes the licensee had made to their emergency action level considerations. That issue ultimately resulted through traditional enforcement as a severity level 3 violation. And we also issued a $60,000 civil penalty for that.

MR. LEITCH: Okay. But was there not a color associated with that?

MR. LOUDEN: No. Not for traditional enforcement.

MR. LEITCH: Okay. I guess I'm not sure I understand that. I would have thought with a violation of that nature there would be a color associated with it. Not so?

MR. LOUDEN: Not because of the enforcement path we went.

Is there anyone that would like to address that from a 0305 perspective?

MR. SCHWEITZER: Pat, Jim Schweitzer from Point Beach. Maybe I can help out a little bit.

It mentioned a white finding. There was an original white finding from a plant exercise that was conducted where our critique was inadequate and we did not identify a missed performance indicator. So there was a previous white finding associated with that. But at the 95003 inspection there were no findings that were greater than green. And we did have this one issue associated with not taking adequate immediate action to address a concern with an EAL, an emergency action level.

MR. LEITCH: Okay. Thank you.

MR. LOUDEN: We completed the 95003 in three parts. It ran from late in July through December. We had three different teams: One looking at the corrective action program in process; one focused on the emergency preparedness program, and; then a third which was a combined look at engineering operations and maintenance to try to look at various other areas. More of an integrated plant operational review.

Next slide.

The teams were comprised mainly of inspectors from other regions and from headquarters to

provide a different viewpoint and a fresher look at some of the issues. The result of the 95003, there were ten green findings from that. All findings were green. And there was one unresolved item, which turned into this severity level 3 violation, NEP, which we just discussed.

Combined with the results of that inspection and the results of our baseline program and the observations from our resident inspectors, we found five general areas of concern that we wanted the licensee to address. And those five areas are on the screen. It's human performance, engineering design control, engineering ops center face, EP and the corrective action program.

Next slide.

These five areas then became the basis for what would be the areas that we identified in our confirmatory action letter. And we issued that letter on April 21, 2004.

At the same time when we were working through the 950003 inspection and developing the concerns that eventually led to what was included confirmatory action letter, the license had developed a operating business unit plan they called the Excellence Plan. And that plan consists of a number

of different organizational actions and improvement items. It includes various aspects of the business and the operational end.

From that the licensee developed a subset of actions which they then included in a commitment letter that they sent to us in March of 2004. And we attached that commitment letter in our confirmatory action letter.

We acknowledged that the actions that the licensee had described and given to us, we acknowledged that those actions could be used as measures to gauge improvement in the various areas of concern. There were 143 of these action items.

MR. LEITCH: And one of those in the area of corrective action program, one of those actions states that the number of corrections -- that is as a criteria for whether that action is satisfactory or not, that the number of corrective actions should be less than 2500.

And we're particularly interested in the corrective action program. And I wonder why that's a good criteria? Maybe that's a question for the licensee rather the NRC. Because my concern is that if for a number of years, and apparently this is a program that's been deficient for a number of years,

I would think the goal would be not to limit the number or not to set a goal to try to drive down the number of corrective actions, but rather to in fact bring on as many corrective actions as you possibly can. As people on the site become aware of this new corrective action program, they should be dredging up all kinds of issues. And I would think you would be trying to get that number as high as possible and to encourage people to bring forth those corrective actions, not to limit it to some arbitrary number like 2500.

MR. LOUDEN: Yes.

MR. LEITCH: Now I readily agree that after a few years of working through an effective corrective action program, probably 2500 is not a bad number. I think most sites are about at that number. But I would think when you're trying to have a remedial program, it doesn't make a whole lot of sense to limit the number. In fact, I think you should be encouraging a higher number.

CHAIRMAN BONACA: In fact, I second that comment, Graham. And particularly in consideration of the potential legacy issues. I mean, there may be issues that have been there for a long time, they've have not been resolved, and I think only if you really

open the dates and you encourage people to bring up anything they had, they're going to do it with them. Otherwise, you're going to have this stale of legacy issues that take a long time to address and close.

So I think I don't understand the limitation at that point.

MR. LOUDEN: I'll offer at least the way we're using that number, and then certainly I would like the licensee to address the way they approach this.

That particular item for 2500 open corrective actions is for the open ones. We viewed it almost as a backlog reduction type of an approach to an issue. It's not about generation rate or initiation rate. I mean, certainly and I'll the licensee speak to the numbers as far as what their generation rate per year is of identified issues.

MR. LEITCH: Okay.

MR. LOUDEN: The point here of that particular item that you mentioned, sir, we at least are viewing it as a gauge to measure progress in addressing issues and getting them closed and resolved is the way we're viewing.

But for the rest of that, Jim, I will turn that to you.

MR. SCHWEITZER: Yes. Again, Jim Schweitzer from Point Beach.

Pat is correct. The 2400 number is a backlog goal for us. Our initiation rate last year was about 8,000 item initiated. And that number went up by almost a factor of two following the issue of the red findings and our improvements in our corrective action program.

The basis for about 2500 is associated with trying to make sure we get timely resolution of the items. Because identification was not a big issue for us. It typically went into timely resolution.

If we look at that generation rate and look at about 120 day nominal turnaround for all items, you can come up with a backlog of about that number.

MR. LEITCH: Okay. So last year the initiation rate then, just to repeat what I think I heard, was more like 8,000 then?

MR. SCHWEITZER: That is correct. The initiation rate was about --

MR. LEITCH: Okay. I misread then the criteria here that you've established. I think that's a good clarification.

MR. LOUDEN: Okay. Next slide.

As far as inspections for last year following the count, within our baseline inspection program we conducted two inspections; our safety system design and performance capability inspection which looks into engineering issues and a problem identification and resolution inspection.

Both of those inspections we enhanced by adding additional inspectors, almost doubling on each of those, the number of inspectors that were looking into the issues.

Besides using the baseline inspection procedure guidance, we used that and we also were using looking at corrective actions the licensee had taken with regard to specific CAL related items to do a progress or status check along the way there.

We also conducted two special inspections last year, and the purpose of those special inspections were to specifically look at and evaluate progress that the licensee was making in addressing these 143 items. The items as they're presented and listed here are in kind of a sequence series step-wise type approach to some of them. So there were a number of them which were available to be evaluated if actual progress was being made. And some of them the licensee had committed to also do interim effectiveness

reviews. So, again, it was another opportunity for us to evaluate if things were being addressed in a timely manner by the licensee per their commitment letter.

MR. LEITCH: One of the things that always concerns me about these improvement programs is we tend to look at the beans rather than the results. A number of these things to verify that the objective has been met is -- I'm just looking at this TRP for example. It says that the TRP has been established. That they've generated minutes from their meetings and so forth. But the real crux of the matter is that the third bullet under that, which is the effectiveness. In other words they've done these things and that's kind of easy to document and so forth. But how effective has it been? And my question is does the NRC really look at all at the effectiveness of those actions?

MR. LOUDEN: Absolutely. If you look at progress, and I'm just gauging a number that I looked at a few weeks ago in answering another question. The licensee's progress on completing their items here are further along than what we are with our inspection because we lumped a great deal of what we wanted to look at here in the coming months yet this year, particularly so that things were closed out. Because

the latest date in the commitment letter is 2Q05.

MR. LEITCH: Yes.

MR. LOUDEN: But things were closed out. And, yes, we did want to focus on the effective reviews of each of those item. So that was a key point. And when we set up our monitoring was that we were weighted at the backend to do just as you suggested; to look at the effectiveness of it. Because you're right. We can follow the progress and you can hit the marks. But if it doesn't fix it, it's not that valuable.

So we are prepared to do when the time is right when the licensee has completed their actions, we will come in and do a more thorough completion inspection that will focus on that end product, the effectiveness. Were the actions that the licensee took effective and sustainable?

MR. LEITCH: Just let me just clarify that. Do you review the licensee's effectiveness review or do you sometimes also do an independent effectiveness review?

MR. LOUDEN: We do both. We look at the licensee's effectiveness reviews and gauge the quality of those. And if they seem to hit the mark, ask the right questions. We also through our day-to-day

inspections, and especially with the resident inspectors on site everyday if we see or issues or examples of where maybe performance is not as characterized here or maybe there's some questions in a certain area, certainly we would explore and use that as a vehicle to dig in. That is our independent look.

MR. LEITCH: Okay. Thank you.

MR. LOUDEN: Yes. You're welcome.

So those two special inspections were completed last year. And they look at the progress that the licensee was making with the confirmatory action letter.

Next slide.

Within the ROP, I just wanted to point out that both the human performance area and the problem identification and resolution areas are considered substantive crosscutting issues under the ROP. The PI&R area that was identified as such in our end of cycle letter in 2003 and human performance in our end of cycle letter in 2004. And as I already mentioned, those two items are also two of our five issues that we're following up in the confirmatory action letter.

Next slide.

With regard to the human performance area,

our current assessment. We have noted in the last year improvement in the human performance area. The licensee has focused a number of initiatives in addressing various aspects of human performance; error reduction techniques, briefings. And they have various vehicles that they've devised to address the human performance issues.

What we're evaluation is the frequency and the significance of the errors when they do occur.

MR. SIEBER: Do they have performance indicators that show error rates and if they do or do not, how do you evaluate those?

MR. LOUDEN: I believe they do. I'll let Jim. The question was do you have performance indicators that look human performance error rates.

MR. SCHWEITZER: Jim Schweitzer from Point Beach.

Yes, we do have performance indicator. We track what we call like a clock reset which looks at a human performance error. We have that at the site level and each department has their own criteria that's associated with that. And when we do have a clock reset, then we do what we call a human performance investigation to understand what occurred, why it occurred and what corrective actions we need to

put into place.

MR. SIEBER: Typically, how long does your clock run before it resets? Is that hours, days, weeks?

MR. SCHWEITZER: It various through departments. For engineering right now we're just about 14 days between, that's been on a steady increase.

The site clock reset is running close to 100 days I believe right now between clock resets.

Some other department like maintenance is working on trying to develop better plans. They're running about 3 days to 4 days between a clock reset in that department.

MR. SIEBER: That's not too good, right?

MR. SCHWEITZER: No. Three to 4 days is not good there.

We look at a great number of different levels of things from procedure issues getting on the run, work order. The level we set the threshold very low within the department so that we take those as learning opportunities there to figure out what to do so we do not challenge the site clock reset.

MR. LEITCH: Now the criteria.

MR. SIEBER: And so --

MR. LEITCH: Excuse me, Jack. Go ahead.

MR. SIEBER: And the site clock has a much more liberal allowable problem area than the departmental?

MR. SCHWEITZER: The site clock, each one has defined criteria.

MR. SIEBER: Right.

MR. SCHWEITZER: It defines specific criteria to reset the clock. For the site it's at a much higher level than the departments. So for a procedure, a violation or not following the procedure correctly would be a clock reset for a department. IF it had no consequential issues or problems that affected the plant, it would not be a clock reset. If it was a procedure violation that resulted in a plant transient, then would be resetting the site clock from it.

MR. LEITCH: So the criteria for successfully accomplishing your goals here is listed as less than -- or greater rather than 36 days between resets of the site clock? And that number is up around 100?

MR. SCHWEITZER: That's correct.

MR. LEITCH: But the maintenance clock is resetting much more frequently than that. But the

reason again is that the maintenance threshold is set to trigger at very low values?

MR. SCHWEITZER: That's correct. For the departments we set the threshold much lower because there you're looking for learning opportunities to make sure that we will correct human performance issues at the very low level so they do not challenge the plant.

MR. LEITCH: Yes. Sometimes, though, the difference between a low level event and a more serious event is really only --

MR. SIEBER: Happenstance.

MR. LEITCH: Yes, happenstance or luck. I hesitate to say luck.

MR. SIEBER: Luck?

MR. LEITCH: The way the stars are aligned or something at that time. But you know, these low level events cannot be disregarded either. And, you know, with maintenance clock resetting like every four days, that seems to be of a concern. And I guess you are concerned about it.

MR. SCHWEITZER: That is a concern from the plant. And like I said, each one of them we do take the learning opportunity from. Each one of the clock resets will be entered into our corrective

action process and we'll do the human performance investigation to understand it and to look at the significance of it. And there are -- in the maintenance department and the departments that are not meeting their actual goal, they are developing long term plans. They're going back and looking at what are the common cause and why are they not being effective in improving the overall human performance within those departments. They have human performance steering teams that are established that are made up of various levels within the department including individual contributors to help.

MR. LOUDEN: And that is how we use the information from the performance indicator to gauge the significance, if they are significant events or not.

And also, for the clock resets I parallel that to like the corrective action with condition reports, the corrective action program reports that are generated. You could have a large generation rate, but if you're not hitting the mark or if you're not identifying the right level or threshold of issues, then it's not improving anything.

So not just looking at the clock either resetting frequently or not, we also look at the

actual issue. And then once it's entered into the corrective action program, then how are the corrective actions established and are they effective.

MR. SIEBER: Let me ask this: You're from Region III, right?

MR. LOUDEN: Yes, sir.

MR. SIEBER: And there are several plants in Region III that use the clock concept?

MR. LOUDEN: I'm aware of several, yes.

MR. SIEBER: Okay. So without naming names, how does the thresholds at Point Beach match the threshold levels at some of these other plants where I've worked in Region III?

MR. LOUDEN: The last plant I was at is the only one I would have any real reference to. And I don't see anything that different at Point Beach than what I'd seen. But I can't get into specifics. I don't have recent information to do any type of true comparison.

MR. SIEBER: Okay. Okay. I'll withdraw the question.

MR. LOUDEN: Okay.

MR. LEITCH: One of the things that I always use to judge the effectiveness of the corrective action program is how many of the items

that are being recorded there are identified by the line organization versus what I would call external organization, that is the QA, the NRC, INPO, offsite review committees and so forth. Do they have such an indicator to show what the percentage of that is?

MR. LOUDEN: I believe you do. I believe you do.

MR. LEITCH: How is that behaving?

MR. SCHWEITZER: Yes. Jim Schweitzer at Point Beach.

We do have an indicator. We call it our self-identification ratio. We look at the site to make sure that as a site we are identifying our own issues. And also on a department level we will look to make sure that each department is identifying issues within their department. And we have benchmarked that against the industry and looked at what percentage we expect to be within. Like within engineering, the industry standard is like 30 to 40 percent as identified by engineering. We've been running in the 60 percent range.

MR. LEITCH: And I think that's a very important indicator to show the overall health of the corrective action program. The line employees, you know, the in-line people really believe in it and are

entering things into the corrective action program. And if they do that, probably the problems are being solved. I mean, after a while people won't put stuff in if nothing's happening as a result of it. So I think it's healthy to see a high percentage of self-identified items in the program.

CHAIRMAN BONACA: One question I have was could you comment on, you know, you identify areas who needed improvement. And could you comment on the site review committee, the quality organization? I mean, what are those organizations? How effective were they or do you find there are problems there, too?

MR. LOUDEN: Are you asking the site or like offsite safety committees?

CHAIRMAN BONACA: Yes.

MR. LOUDEN: Is that what you're asking?

CHAIRMAN BONACA: That's right. Like reorganization. I mean, clearly when you have these kinds of problem go corrective actions it means also that the oversight organizations goes which are specific, like Appendix B and the general view are also probably defective somehow or they just didn't see the problem themself. It relates to the question that Mr. Leitch raised, I mean, about self-identification on the part of the site.

MR. LOUDEN: Not specifically called out in the CAL, but part of the licensee's commitment letter where they broke down the various area. One of the areas where they acknowledged that they needed to place some improvement on was within the nuclear oversight area. And the way we've approached that is to gauge the actions that the licensee is taking going forward. And we have seen improvement in the NOS organization which you commonly known as the quality assurance organization. We have seen improvement in that area with regard to the types of people who are assigned to that department and the overall activities that the organization does. And the responsiveness that the audited organization has to QA findings.

I don't know, Jim, if you wanted to offer anything from that action plan item.

MR. SCHWEITZER: Jim Schweitzer, Point Beach.

We developed an overall action plan to improve our nuclear oversight because we did recognize that we missed opportunities with that department to identify issues and problems, and to help drive them to resolution.

What we did is improve the -- we took some individuals out of the line organizations, higher

level individuals, to put them into that organization. We initially pulled an SRO, who is an ops supervisor and put him into that organization. There was an RP, radiation protection supervisor that went into that organization. We pulled from the NMC fleet, too, a recent NOS manager a recent NOS manager was the ops manager at Palisades. Looking for that good strong leadership and ability.

We also revamped the program and developed what we call a problem identification report which takes the issues and drives them more into identifying what the problem is, working with the line organization to come to those conclusions. So we've driven more ownership to the understanding and resolution of the issues found by NOS into the line organizations.

That's been very effective in resolving some of our QA significant issues. We had a number that have been open for a long period of time, increased sit attention to them. And the added improvements of NOS has been able to drive those to resolution in much more timely fashion.

CHAIRMAN BONACA: Yes. I'd like to ask also a question about the commitments which are referenced in the CAL. Have they been fulfilled on

time? I mean, there were commitments and schedules for those, and what's your assessment?

MR. LOUDEN: A majority of them are being met on time. There are a few that are going to run beyond the original date as described in the cover letter for the -- the confirmatory action letter.

The licensee was required to notify us of any items that were not going to meet the dates. And they have submitted, I believe it's two letters, to us that have described a few of the action plan items that were not going to meet the original commitment dates.

CHAIRMAN BONACA: Now on your assessment letter of March 2, 2005 --

MR. LOUDEN: Yes.

CHAIRMAN BONACA: -- indicates that corrective action program still has problem. I mean, one problem identified in the third quarter and fourth quarter. How does it jive with the second bullet there where you say the corrective action program is sound?

MR. LOUDEN: Okay.

CHAIRMAN BONACA: I don't understand that message.

MR. LOUDEN: All right. I'll try to explain.

The purpose of the bullet there, the corrective action program is sound, what I'm trying to differentiate here is the program, meaning the design program, the process, the procedure, what is being written up and used not only at Point Beach but I believe this is a fleet wide program for NMC. So what I'm trying to differentiate here is the program itself is sound as a program. It has all the elements and the components that one would want in a good corrective action program, meaning the identification piece, the reviews and the management oversight of the program and various components like that. That is what I was trying to define there, was just the program itself.

The issue that you're referring to in the letter and that we've discussed with the licensee is on the implementation aspect of that program. And in particular, the areas that we're looking at continuing to monitor closely within the corrective action program are the timely resolution of issues when they're identified. And, again, have the issues been properly reviewed for extended condition and not just so limited focused on the one particular problem, but also trying to understand where else could similar problems occur.

CHAIRMAN BONACA: So how good are their

root cause evaluations in your judgment?

MR. LOUDEN: Well, the way we're evaluating it is right now we've had no findings or issues, particularly with root cause evaluations.

One of the things that the licensee is gauging the root cause -- or their corrective action program on is their own grading of root cause evaluations and corrective actions. And, Jim, do you want to comment on what you do for root cause evaluations?

MR. SCHWEITZER: Jim Schweitzer, Point Beach.

For root cause evaluations we do have a complete instruction manual that's set up on how to do a root cause evaluation. Individuals need to be qualified to that. Teams are established for it. And we have developed the charter. The charter does come back to either our corrective action screening review committee or to our corrective action review board.

A sponsor is assigned as a management sponsor.

For improvements in the process of it we do do periodic reviews of the status of the root cause, how it's progressing, any difficulties or problems. And then in the final root cause, all root

cause do go to our corrective action review board that's made up of senior managers on site. And those are reviewed and detailed. And then we have a grading system that we apply to it.

In addition to that we have follow-up items that all the actions that we call corrective actions to prevent reoccurrence come back to the corrective action review board after they are completed for review and effectiveness reviews that are done also come back.

So we have a way of looking at the quality of the product as it's being prepared, when it's issued and then we have follow-up actions to make sure that the actions were effective.

MR. LOUDEN: And we independently review root cause evaluations. And I think that two of the areas that I just mentioned that we're still looking at are sometimes there are questions that we have with their root cause evaluations that fall into that area. A number of times we will ask questions that dig into a little deeper. How broad is this problem? Has the overall extended condition been captured on this issue or not? So we still have questions on that.

And we're looking at this program very closely. WE're planning on doing another problem

identification and resolution inspection in September of this year. And the focus of that inspection within the baseline inspection procedure will be to look at the timeliness of the actions taken, the overall quality of root cause evaluation and casual issues like that.

CHAIRMAN BONACA: Because I mean that's a critical window, the quality of the corrective action program, how effective is their evaluation of the issue, they prevent the reoccurrence. I mean, that should tell you something.

And, you know, from the representation it's clear that you have a program with all the elements in place. The question is how far do you go into the implementation and how well those themes are coming up with the fundamental causes.

MR. LEITCH: Is PRA a factor in determining which corrective actions get a full root cause analysis?

MR. SCHWEITZER: Jim Schweitzer, Point Beach.

MR. LEITCH: Let me ask the question. I assume you categorize levels of corrective actions to determine severity or importance. And I guess my question is do you use PRA in determining which ones

are of the highest significance and therefore require a root cause analysis? I don't think you do root cause analysis on every corrective action?

MR. SCHWEITZER: No, we don't. We do not specifically use PRA to make the evaluation, but we do look at safety significance.

Every morning we do a screening of all of the corrective actions that were initiated within the last 24 hours. And they are categorized from alpha down through a delta category. We have specific criteria for each of those categories based on safety significance of the issue.

And all of our alpha level significance do receive a root cause evaluation. Bravo is made based on the discretion of the screen team and typically at least receive what we call an apparent cause evaluation.

MR. ROSEN: So the alphas would include components in systems that are highly risk significant?

MR. SCHWEITZER: That's right.

MR. ROSEN: For instance, aux feedwater problems you had now would be considered alpha problems now?

MR. SCHWEITZER: Yes, they were. In fact

there were two root causes that were done on the aux feedwater issues.

MR. ROSEN: So in a sense you do use the output of the PRA from a risk significant standpoint to inform your decisions about how much review you do of each of these?

MR. SCHWEITZER: Yes. All the members are cognizant of the PRA, the highest risk significant systems. So we are aware of that and that helps in the overall decision.

MR. ROSEN: Now let me come back to your point on the slide here. We understand what you mean I think now why the corrective action program is sound. But the rest of that sentence still puzzles me. "However, some areas are still in need of improvement." Is that a comment about the program itself or the implementation of --

MR. LOUDEN: It's actually meant to be the implementation piece.

MR. ROSEN: Oh, okay.

MR. LOUDEN: That was the intent. I understand how you interpreted that. But the intent of the bullet was to make a separation and then transition into the implementation aspect.

MR. ROSEN: While I've got you, on your

earlier slide on the five areas of concern, you had an item on engineering operations interface, which I'm interested in. Can you say a little more about that? I don't think you said much. What was the nature of that concern?

MR. LOUDEN: The nature of the concern, the specific concern in the 950003 report I believe had to do with communications and understanding between the engineering and the operations department for certain offsite or grid issues. And there were also some issues raised that the inspectors noted between an understanding of certain fire protection instructions that the engineering department had versus the understanding that the operators had.

MR. ROSEN: For instance, the fire brigade?

MR. LOUDEN: I don't think it was fire brigade, but I don't recall the exact issue. But it was a communications type of issue of two organizations that had different points of what was being done. So our observation was that to be more effective, and it spilled over into the operability determination process. This is an evaluation process I'm sure many of you are familiar with. When a system is identified as a potential operability question, an

evaluation can be done.

The two groups that are highly dependent upon on discussing and being on the same page with each other, are the engineering and the operations group in resolving such an issue. That is an example of an area where we identified and had questions that we would encompass under the engineering/operations interface. And we have seen improvement in that area.

The licensee early on just in 2004 just after the issuance of the confirmatory action letter implemented what they called the Operational Decision-Making Issue process. And it takes into account the various aspects of the organizations involved to get to the bottom of an issue.

And I don't know, Jim, if you wanted to talk about what ODMI process is?

MR. SCHWEITZER: Jim Schweitzer, Point Beach.

ODMI process, as Mr. Louden mentioned, is to help us make operational decisions. What it is is to a little more regimentally step us through making those decisions, get the right individuals involved so that it's not being made purely from an engineering perspective, from a maintenance perspective or from an operations perspective.

So what it does it lays out kind of what the issue is, what's the immediate risk, what's the long term risk, what are some of the possible solutions and then it goes through a ranking process to make sure that everybody understand what the issue is, how we're addressing it in a logical way to step through it.

A couple of other things that Pat mentioned a little bit on operability determination. That's an area that we worked on to really establish a good relationship between engineering and operations. To understand and develop the communications up front when there is an issue that's being identified by engineering to get the operational perspective, knowledge put into it to make sure that operations knows what the issue is. They're not caught by surprise when we come to resolving it. And to drive it through a very regimented process that we have for documenting the operability determination, the basis for it, the requirements that are out there. Our internal review and then an SRO review and acceptance.

So a lot of the interface and the things that we put in place, a lot of them are processes to help drive that interface. The operability determine

was one, the ODMI is one, and then as mentioned earlier our design review board for modifications is another one.

As we go back to one of the red findings associated with aux feedwater, one of the lessons learned we got out of that from our root cause is that we did not have all those perspectives. Okay. We were trying to solve one specific issue and did not look at all the operational issues associated with it. So that's now why we require that for all safety related modifications that we do have this review board to set up. That all the members are dedicated and required to review, would sign that they've reviewed and accepted and understand what we were doing as far as a modification. That's been very effective for us. It's been in place for I think almost two years now.

MR. ROSEN: Is that true of ODMI as well?

MR. SCHWEITZER: For ODMI, yes, will identify all of the stakeholders that are part of that decision.

MR. ROSEN: No. I was asking about how long it's been in place?

MR. SCHWEITZER: ODMI has been in place for almost a year now I believe.

MR. ROSEN: So on your next slide, Mr. Louden, you have a statement that there's been progress made on all five of the confirmatory areas?

MR. LOUDEN: Yes.

MR. ROSEN: And can you tell me what progress there is in the engineering operations interface that you mean there? Just the OMDI process or have you seen specific examples where it's been used and been effective?

MR. LOUDEN: What is meant there is that we have seen improvement in performance. And the performance piece of that is with the way the OMDI has been implemented, not just the fact that they developed one and put it on the books. But it has been implemented.

We've seen resident inspectors who spend a lot of time working with operators and observing things in the control room.

Have seen improvement in the responsive of engineering to operational issues.

So not only have we seen changes that they've made programmatically, but we see it day-to-day with actual face-to-face interactions is the intent of the improvement there.

We're next slide. Okay.

Yes. The five areas we have seen improvement in all the five years. There are varying degrees of improvement within the five areas.

I want to make sure I answer your question on the state of the corrective action program. The corrective action program, our assessment of it, it is adequate right now as implemented. I mean, it is functioning. And if we ever had a concern with the functionality or the ability of the corrective action program to identify real issues, well that is a criteria that we would have to then revaluate. In 0305 we would have to then step back and reevaluate should the NRC take other actions or additional actions when it concerns a raise regarding the wholeness of the corrective action program.

Our focus --

CHAIRMAN BONACA: Another question.

MR. LOUDEN: Yes, sir?

CHAIRMAN BONACA: That's not the message I get from the annual assessment letter. It sounds somewhat different. That's why I asked that question.

MR. LOUDEN: Okay. Our focus this year, and our real focus throughout has been not on just a checkoff type approach to actions taken, but we're focused on lasting improvements. So our focus going

forward is not only assessing what actions have taken and has there been short term success, but we're also going to be focusing on the sustainability of the long term effectiveness of the actions. And that's what we're going to be looking at going forward here this year.

CHAIRMAN BONACA: Good.

MR. LOUDEN: That completes my prepared remarks.

MR. LEITCH: Could you outline for me, I think we've alluded to this but just again quickly, what's the sequence for closing out the CAL? Does the licensee come to the NRC and say we're done with all this stuff and then you go in and inspect or how does that work? And what is the relationship of closing the red findings to closing the CAL?

MR. LOUDEN: I can describe what I have scheduled, and it's all based on the licensee's completing given action at a given time.

MR. LEITCH: Right.

MR. LOUDEN: And as the licensee completed an area and that area is done, say all the action plans, what they refer to as action plans, for a given area are complete they send us a letter, basically. Here's the way the process works. They send us a

letter that identifies which packages are complete and they tie it to whatever action plan it is. If it's a human performance one or if it's a nuclear oversight or engineering, or whatever.

We will then go in and we're going to then do inspections in each of the five areas --

MR. LEITCH: Yes.

MR. LOUDEN: -- to look at not only the completeness of the actions taken, but then to do an assessment of the overall effectiveness of those. That's what I have planned for inspections scheduled out through this coming summer. Given if the licensee is complete in the areas, that's the way we'll go through it.

MR. LEITCH: But these red findings are still open?

MR. LOUDEN: Yes.

MR. LEITCH: And they're open because of the more systematic issues that are outlined in the CAL?

MR. LOUDEN: That's correct.

MR. LEITCH: So when the CAL closes the red findings kind of dramatically close?

MR. LOUDEN: My understanding of 0305 is that they could be considered separate. The only tie

that I am aware of in the program is the red findings would be tied to where the licensee would be within the action matrix.

We could -- you know, you could have a situation where you could say the specific problems or whatever problems you're assigning to be closure criteria for the red finding could occur, but we could still have issues elsewhere in the CAL. And it could remain open. I guess that's the scenario I'm trying to paint here.

Where we're going, I can't rally speculate on the timing of what will be with what. But it will be -- right now the current schedule we have are to do completion inspection, come in and look at the CAL closeout actions. And then decisions will be made at that time what's the order or how will things be closed or will they be closed at that time.

MR. LEITCH: Okay.

CHAIRMAN BONACA: Any other questions by members? If not, I thank you very much for your presentation. It was informative. And I appreciate your coming to inform us.

MR. LOUDEN: Okay. Thank you.

CHAIRMAN BONACA: Thank you.

I just have one final question, actually,

I forgot to ask you. You have inspectors doing this review. You also had inspection from the region inspecting licensee renewal commitments. I mean, you participated in that way. Do these teams talk to each other?

MR. LOUDEN: Yes. Our regional -- all the teams that have been onsite at Point Beach both represented from the region and from headquarters have been in direct discussion with the senior resident inspectors. They discuss what areas they're looking into to try gain insights from the residents. Are they aware of any certain issues? So, yes, they do talk.

CHAIRMAN BONACA: There is communication?

MR. LOUDEN: Yes, sir.

CHAIRMAN BONACA: Okay. So then we can move to the next presentation. I believe that's from the applicant.

MR. JOHNSON: Chairman Bonaca, would you like us to start or would you -- would you like us to start at this point. I think we all have the paper of it.

CHAIRMAN BONACA: You can start referring. We have slides.

MR. JOHNSON: Good afternoon. I'm Doug

Johnson, I'm the Director of License Renewal Projects at Nuclear Management Company.

Here from Nuclear Management Company this afternoon are Jim Knorr. Jim is our Project Manager for the Point Beach license renewal project.

Also Jim Schweitzer. Jim is the Director of Engineering at Point Beach.

And also here from NMC are the core members of the Point Beach license renewal project team. And that includes John Thorgersen, Mark Ortmayer, Bill Herrman, Brad Fromm, Todd Mielke and Steve Schellin.

MR. SIEBER: There's been reference to the fleet of plants that are operated by NMC. What plants are in the fleet, for the record?

MR. JOHNSON: The Nuclear Management Company currently operates Point Beach, obviously, Kewanee Nuclear Power Plant, Monticello Nuclear Power Plant.

MR. SIEBER: Prairie Island?

MR. JOHNSON: Prairie Island, Duane Arnold.

MR. SIEBER: Palisades.

MR. JOHNSON: And Palisades.

MR. SIEBER: Okay.

MR. JOHNSON: In fact, from Palisades here this afternoon is Darrel Turner and Bob Vincent. They are the Project Managers for the Palisades license renewal project.

We're also expecting, hopefully shortly, Doug Cooper is our senior Vice President. And we are expecting that he will join this meeting shortly.

And Jim Knorr will present an overview of the Point Beach license renewal project?

MR. KNORR: Okay. Good afternoon. My name is Jim Knorr. I'm the Manager of the license renewal project for Point Beach.

As Doug was saying, we have an operating company that operates Point Beach. It's Nuclear Management Company, LLC. Their headquarters are in Hudson, Wisconsin. And the owner of the plant is We Energies. You probably know them as Wisconsin Energy, which you can find on the market. So Nuclear Management Company is the operator and We Energies is the owner.

We're located in a small township on the west shore of Lake Michigan, Two Creeks, Wisconsin.

Westinghouse two-loop PWR. Our rated power at this point is 1540 megawatts thermal. And the rate of electrical output is 538 megawatts electric.

We have four emergency diesel generators. We have a 25 megawatt combustion turbine.

CHAIRMAN BONACA: Okay. Just a second. The four emergency diesel generators, are they two per units?

MR. KNORR: Actually, they are -- our plant is licensed to operate with two diesels. The four diesels, any one of the four diesels, and correct me if I am wrong here, Steven, but anyone of these four diesels can serve any one of the safety-related loads on the site.

MR. SCHELLIN: Both safety-related.

MR. KNORR: Both safety-related diesels, right, can serve any one of the --

CHAIRMAN BONACA: So there are only two safety-related diesels? I'm trying to understand.

MR. KNORR: No. All four are safety-related diesels.

CHAIRMAN BONACA: Okay.

MR. SCHWEITZER: Our design is such we initially had a plant that had only two safety-related diesels, alpha and bravo train that were common to the site.

CHAIRMAN BONACA: To the site.

MR. SCHWEITZER: We added two more diesel

generators, but when we added them we maintained the flexibility for the alpha, like the alpha emergency diesel generator to supply either Unit 1 or Unit 2 alpha bus or both processes.

CHAIRMAN BONACA: But right now you have two dedicated to one unit, two to the other one, they're interconnected?

MR. SCHWEITZER: Normal lineup is to have one diesel dedicated to each bus on each unit.

CHAIRMAN BONACA: Okay.

MR. SCHWEITZER: One diesel to the alpha bus on Unit 1, one diesel to the alpha bus on Unit 1, one diesel to alpha, one diesel to bravo on Unit 2.

MR. ROSEN: So that the diesels can start in the required start time on either safety bus?

MR. SCHWEITZER: That is correct.

MR. KNORR: That's correct.

MR. ROSEN: There will be safety-related power to either safety bus?

MR. SCHWEITZER: Yes.

MR. KNORR: Yes.

CHAIRMAN BONACA: So if you do have an event at plant one, you start all four diesels if you have lose of offsite power?

MR. SCHWEITZER: If you'd have total loss

of offsite power, yes, you would start all four diesels because you'd get the under voltage on all of the buses.

CHAIRMAN BONACA: Okay. If you need, however, emergency systems on one unit, you would start only two? I'm trying to understand how the logic works. And two will be standby?

MR. KNORR: That's correct.

CHAIRMAN BONACA: I would expect you don't run all four of them.

MR. SIEBER: Well, it sounds the same as a regular plant that put the cross ties as an afterthought.

CHAIRMAN BONACA: Yes.

MR. SIEBER: Here the cross ties were designed in at the original construction. And I presume you operate with cross ties open? That would be the normal operation position?

MR. SCHWEITZER: Yes. Normally a diesel would be dedicated.

MR. SIEBER: So if you get a loop on one unit, you get two diesels? If you got a loop on the whole plant, you get four?

MR. SCHWEITZER: Correct.

MR. SIEBER: And anyone of them could

supply both buses on both units? But to get redundancy you'd two?

MR. SCHELLIN: This is Steven Schellin, the electrical lead for license renewal.

I think the key point is that each diesel has the capacity to supply both units safety loads on a single train, alpha train or bravo train.

MR. SIEBER: Right.

MR. SCHELLIN: And as you stated, we have them aligned so that one diesel is on the Unit 1 alpha train and it's corresponding twin diesel is on the alpha train of the other unit. And similar for bravo. And so if you had an accident or some event that caused one unit to have a need, two of those diesels would start based on the logic from that unit.

If you had a loss of offsite power, all four diesels would start and you would have twice the capacity needed to serve the safety loads on both units available via the diesels.

MR. SIEBER: And I presume the tie breakers are voltage chasers, right?

MR. SCHELLIN: They're manual.

MR. SIEBER: They're manual?

MR. SCHELLIN: Operated from the control room.

MR. SIEBER: Not voltage chasers?

MR. SCHELLIN: Correct.

MR. SIEBER: Okay. So if a diesel doesn't start with that bus tie open, you have to have an operator action in order to --

MR. SCHELLIN: Yes.

MR. SIEBER: -- save the unit?

MR. SCHELLIN: That's to prevent an event from one unit from taking the diesel from the other unit --

MR. SIEBER: And possibly --

MR. SCHELLIN: -- without some judgment being made.

MR. SIEBER: Yes.

CHAIRMAN BONACA: So just to finally connect it completely, you have a lock on one unit. One diesel will be sufficient to power all that division of -- that you need.

MR. SIEBER: Yes.

CHAIRMAN BONACA: Okay.

MR. SCHELLIN: Correct.

CHAIRMAN BONACA: You don't need to -- okay. Thank you.

MR. SIEBER: Who owns the combustion turbine? Is that the system operator or the plant

operator?

MR. KNORR: The combustion turbine can be started by the plant, but also I believe there's a capability to operate at that and start it remotely.

MR. SIEBER: I presume that's the system wide blackstart device?

MR. SCHWEITZER: It is credited at this time for station blackout for us, correct.

MR. SIEBER: Okay.

MR. SCHWEITZER: Starting of the gas turbine would be at the direction of our system controller going through the control room. It is operated and controlled by onsite personnel.

MR. SIEBER: Okay.

MR. KNORR: Okay. Our ultimate hat sink is Lake Michigan. It is a once through cooling system.

Our containment is a post-tension steel reinforced concrete containment with a steel liner.

And we operate right now with 18 month fuel cycles.

I think it would be interesting for this Committee to understand what our operating experience is for those passive pieces of equipment that we have, and what I included in this slide were the two events

that we've had over the years of Point Beach operation which are the larger pieces of passive equipment that we have seen some failures in.

In 1975 in February of '75 Unit 1 had a steam generator tube rupture. The cause was intergranular stress corrosion cracking. Early in the life of that steam generator we used a phosphate chemistry. And since, of course, we have not used that. But nonetheless that was the detail there.

In 1999 we also had a feedwater heater shell failure. That heat exchanger we had heard of some operating experience about a month or so prior to this event happening. And we were in the process of evaluating an operating experience and about ready to include that heat exchanger into our flow-accelerated corrosion program when in fact the feedwater heater did fail. So it was due to some steam impingement and some flow accelerated corrosion on the shell.

This is a slide that talks a little bit about our current performance. And I know that Pat Louden talked at length about this, but all of our performance indicators at this time, NRC regulator oversight process, are green. And as you know, we have a couple of red findings related to the aux feedwater design that were issued in 2003.

It's important to understand that our plant in case of Unit 1 has been operating almost for a complete year as we sit here today. But the 18 month capability factor is at an 87 percent range. The last automatic trip was in July of 2003.

And in the case of Unit 2 we're in a refueling shutdown at this point. And it's 18 month capability factor is about 89 percent. And it's last auto trip happened also in July of 2003.

MR. ROSEN: Was there something about July 2003 that's special?

MR. KNORR: That was a bad month.

MR. ROSEN: Was it weather related?

MR. KNORR: No, it was not weather related. Both of them happened to be equipment failures. In the case of Unit 1 it was a voltage regulator on a motor generator set for the rod drive system. And on the case of Unit 2 it was a failure of a main feed pump. In both cases failure of some active pieces of equipment.

Okay. I want to talk a little bit about the major improvements to capital investment that we've made in the plant over the years.

New steam generators were installed at Point Beach for both units. In Unit 1 it was 1984 and

in Unit 2 it was 1997.

CHAIRMAN BONACA: What kind of steam generators?

MR. KNORR: These are Westinghouse.

CHAIRMAN BONACA: Alloy 600?

MR. KNORR: In the case of Unit 1 it's Alloy 600 with additional hardening for the Alloy 600. And in the case of Unit 2 it's Alloy 690 for the tubes.

CHAIRMAN BONACA: Okay.

MR. KNORR: Okay?

CHAIRMAN BONACA: How is performance of Unit 1 versus Unit 2?

MR. KNORR: Frankly, both steam generators in both units are in very good shape. We've had very little in the way of tube plugging on both unit steam generators. Most of it is due to original construction flaws that we've had.

MR. SCHWEITZER: The other is wear at the anti-vibration bars. That's all we're seeing in Unit 1 at this time. There have been no other indications from express corrosion intergranular attack. It's just a handful of tubes that have been plugged on Unit 1 associated with the anti-vibration bar wear.

MR. KNORR: The water chemistry seems to

be very successful with both units.

CHAIRMAN BONACA: How much piping replacement have you had for FAC?

MR. KNORR: I'm afraid I can't answer that question. Jim, can you --

MR. SCHWEITZER: FAC replacement? Nearly all of our secondary side extraction lines have been replaced with stainless steel. So all of the steam extraction lines have been replaced. Some of our vent lines we've replaced. We have a little bit of our service water lines with stainless steel in some areas.

MR. ROSEN: Go ahead.

MR. SCHWEITZER: It was fairly aggressive a number of years ago with the FAC program and inspection in the extraction steam, the main steam area. If we continue program right now, and I replace components as their life is determined to be not going to -- the life will not get to the next refueling outage.

MR. ROSEN: This replacement of the steam generators on Unit 1 in 1984 --

MR. KNORR: That's correct.

MR. ROSEN: And you're saying that you have still no defects. That's 21 years.

MR. KNORR: That's correct.

MR. ROSEN: And what is the T_{hot} on that unit?

MR. SCHWEITZER: Five ninety-eight.

MR. SIEBER: No, that's not T_{hot}.

MR. SCHWEITZER: Or five ninety-eight. We're just below 600. We're below the --

MR. ROSEN: Are both units the same?

MR. SCHWEITZER: Yes, both units are the same.

MR. SIEBER: And these are mill annealed tubes now?

MR. KNORR: For Unit 1 they're annealed, yes. And for Unit 2 they are --

MR. SCHWEITZER: Thermally Alloy 690. United 1 600 thermally treated tubing. And Unit 2 is Alloy 690.

MR. SIEBER: What kind of tube support plates? Are they broached holes or just drilled holes, or stainless?

MR. SCHWEITZER: They are the quatrefoil broached holes.

MR. KNORR: Right.

MR. SCHWEITZER: Quatrefoil broached holes.

MR. KNORR: Okay. We have replaced --

MR. SIEBER: The chemistry is the four balance?

MR. KNORR: It's hydrazine for the secondary system.

MR. SIEBER: Yes. Molar ratio balance. Yes. That was Westinghouse's or EPRI's I guess it was, the last one I remember anyway, new chemistry regiment.

MR. KNORR: I can't directly answer that. I know that chemistry does look at the molar ratio. I'm not sure how that's factored into the chemistry control.

MR. SIEBER: Sort of like a little arsenic is good for you, right?

MR. KNORR: It could be.

MR. LEITCH: This feedwater heater shell that failed, did you replace that shell or repair it?

MR. SCHWEITZER: We repaired that shell.

MR. LEITCH: Yes.

MR. SCHWEITZER: It was in a localized area the steam extraction comes in. We also determined that material properties of that heat exchanger are a little bit different because the identical heat exchangers on Unit 2 did not show the same wear. And

all the heaters now in that area are in our flow-accelerated corrosion program for continued monitoring.

MR. LEITCH: Okay. Right.

MR. KNORR: We replaced the split pins for both units in the mid-'80s. And I need to vary that explanation a little bit.

In the case of Unit 1 all the split pins were replaced. In the case of Unit 2 we replaced just the susceptible pins, and I think there were four total. However, Unit 2 has just gone through a complete split pin replacement about two or three weeks ago. So all the split pins are new on Unit 2 and we've seen no evidence of wear or problems with Unit 1.

In the late 1980s we did an upflow mod. What that did is change the direction of flow past the baffle former plates. We installed our two additional diesels, which we talked about a little while ago, in 1994. And in 1998 we actually replaced the Unit 2 baffle bolts in a large portion of the baffle bolts.

MR. SIEBER: Why did you add two diesels? You don't need them for your license.

MR. SCHWEITZER: That was really from a PRA risk aspect. When we looked at it, that gave us

the most significant reduction in core damage frequency by adding the two diesels.

MR. SIEBER: Okay.

MR. SCHWEITZER: So it was an upgrade safety net.

MR. SIEBER: A safety-related diesel is about what, $10 or $20 million? They're not cheap. So you did it for the safety of your PRA?

MR. SCHWEITZER: Yes.

Steve, did you want to comment?

MR. SCHELLIN: Well, I guess two additional items. One, at that point in time there were a number of nuclear plants that had been canceled and there were some diesel generators that just matched ours that were pretty inexpensive, except for refurbishing and shipping them.

MR. ROSEN: You should have got four or five.

MR. SCHELLIN: The second item is that if we had a single diesel that went into a LCO, we had seven days to repair it before we had to take both units down. And now with four diesels we do not have that problem so that we can do a major overhaul or a repair or an upgrade without impairing the safety aspects of the units and continue to operate.

MR. ROSEN: Do you do maintenance online?

MR. SCHWEITZER: For the power break diesel the maintenance is done on line.

MR. SCHELLIN: Yes. Yes, we do.

MR. SIEBER: Thank you.

MR. KNORR: You're welcome.

The Unit 2 baffle bolt replacement was done in 1998. We found little or no difficulty with those baffle bolts. We did find a small number with cracking, but did not see any reason to go on into Unit 1.

In the case of low pressure turbines, we had a change out of our low pressure turbine sets and we now have an integral hub so we don't have to concern ourselves with loose part -- or not loose part, but missile issues with those turbines.

We installed a new training building and a new engineering building in 1998.

And some DC upgrades were completed in the mid-'80s and mid-'90s with new batteries and some DC busses, a new swing battery and bus and a new nonsafety-related battery set that was installed in the mid-'90s as well.

MR. LEITCH: Does your new training building have a plant-specific simulator?

MR. KNORR: Actually, our old training building has a two unit plant specific simulator where both units are actually simulated.

MR. SCHELLIN: Actually, it's in our north service building, which was new at the time.

MR. KNORR: Which was new and it was called our training building earlier. That portion was training at the time.

MR. SCHELLIN: We have the only two units simulator in the world.

MR. KNORR: Yes.

MR. LEITCH: Yes, that's right.

MR. SIEBER: When you talk about the replacement of batteries, did you replace them just because they're like car batteries and they wear out or did you replace them to increase the capacity?

MR. SCHWEITZER: In this situation we actually added additional batteries to the station, another complete battery system. Again, to provide additional backup and capability. And the swing battery was installed so that we could actually do testing, the discharge testing of the battery online without affecting the unit.

There is still periodic replacement of the batteries themselves. And in fact, within the last

year we replaced all the battery cells in two of our safety-related battery systems.

MR. SIEBER: Yes, you have to replace them all at once. You know, you can't just add cells?

MR. SCHWEITZER: You can replace some of them during the time but what you get --

MR. SIEBER: In a single battery he has to replace -- you can cut cells out, but you can't put a new cell in without messing it up.

MR. SCHELLIN: On our DC system we run 125 volts with between 59 and 60 cells.

MR. SIEBER: Yes.

MR. SCHELLIN: Plus we fold a couple of spare cells so that if we happen to have an individual cell failure, we can do a replacement. And the --

MR. SIEBER: Well, you cut it out so you have another cell.

MR. SCHELLIN: Right. And the two new batteries that we put in the mid-'80s were after TMI. In the original plant design we had an alpha and bravo battery that served like the diesels, each unit, a red and blue train of instrumentation. But our white and yellow train were served by motor generator sets. So the motor generator road through any small cycle interpretations but not loss of offsite power. So

post-TMI we put in white and yellow batteries. And then, as Jim said, the swing safety-related batteries so that we can take a battery out of service and do a complete discharge test to match our safety response profile.

MR. SIEBER: So as far as coping time is concerned, you're a long time plant or a short time plant?

MR. SCHELLIN: Short.

MR. SIEBER: Short?

MR. SCHELLIN: We're short.

MR. KNORR: We're a four-hour coping plant.

MR. SIEBER: Okay. So that remains, I won't say a vulnerability because there's a lot of plants like that, but --

MR. KNORR: Right.

MR. SIEBER: -- an area where your PRA would tell you about it. Okay. Thanks.

MR. KNORR: Right.

Next slide.

We did upgrade some portions of the -- in fact a good portion of the service water system in the late 1990s.

For the second time we actually replaced

our plant process computer in the year 2000.

DR. SHACK: Was that because you had a MIC attack or something like that in the service water --

MR. KNORR: In the service water system.

MR. SIEBER: In the process computer.

MR. ROSEN: It hadn't spread to the process computer.

MR. SCHWEITZER: It was associated with that, but it was also to give us a much more redundancy and capability in our service water system. Point Beach service water system is a common system for both units. And it's basically a ring header serving both units. There are a number of components within there that were very difficult to maintain, would require two unit outages to maintain. So what we did is we did several modifications that provided some redundancy and some additional flexibility to allow us to do better maintenance on the system. A number of the valves had never been maintained since startup because of the design of the system. And when we had added additional flow paths and valving, we could continue to do maintenance.

MR. KNORR: Okay. We did redesign our intake structure. Removed the super surface section of it and we lowered it to below the surface.

New containment fan cooler heat exchangers were replaced over a number of years in the early 2000. So we now have all brand new containment fan cooler heat exchangers.

The reactor vessel head are going to be replaced this year. Unit 2 is the spring of this year. Unit 1 is the fall of this year.

We're also scheduled for aux feedwater to replace the motor driven auxiliary feedwater pumps, both motor and pumps, in the years 2006 and 2007.

MR. ROSEN: So you've already done a Unit 2 reactor vessel head replacement?

MR. KNORR: We're nearing completion of that outage.

MR. ROSEN: Did you have to put a hole in the containment to get it in?

MR. KNORR: No, we did not. Our equipment hatch is large enough to get the head to.

DR. SHACK: Did you have any cracking or was this a preventative measure?

MR. KNORR: Jim Schweitzer?

MR. SCHWEITZER: This was more of a preventative measures. We have inspections of both heads a couple of times. We did have to cut out some thermal shelve to get adequate inspection. We did

have an indication on our Unit 1 at last outage that caused us to do a repair of that nozzle. Further evaluation with the vendor and better research identified that the indication came from an area that was an original manufacturer repair. It just gives us an indication that looked very much like a crack and we were unable to inspect it.

So it's really looking at the avoidance going forward for doing those inspections and some improvements in the head that we got also, that will allow us to do our outages more efficiently.

MR. KNORR: Any other questions here? Okay.

Just to go through some real quick slides here on application background.

We did submit in February of 2004. The current licenses like expire in 2010 and 2013.

We did use the standard 2003 LRA format that you have seen for the last couple of meetings here with Farley, ANO, Cook and Millstone. And we have expanded the content of that. I'm sure you all have read, especially in our program section, with the additional information for all the ten elements for all of the programs. That was a change that we thought would make it easier for the reviewers to actually

review each of our programs as well the inspection teams.

MR. LEITCH: Just a curiosity question. Most of the plants that we see are further from license expiration, further out than ten years, than five years, which is the case with Unit 1 here. Is there some particular reason for that? Was there some uncertainty about whether to proceed or --

MR. KNORR: No, there was not. Our asset owner was in the process of getting the okay from our Public Service Commission in the state of Wisconsin for some other fossil units. And they asked us to delay the review for -- or at least the submittal for about two years. That's the only reason.

MR. LEITCH: Okay. Thank you.

MR. KNORR: Sure.

The NRC used the new review process, which you've seen for the last couple of applications as well. So we're no different there.

As far as aging management programs, we have 26 total. All of them are common to both of our units. Twenty-one of them are existing programs and five of them are new. A number of them have exceptions and clarifications to the GALL programs. And I just wanted to talk about a few of the

exceptions to give you some examples of what those might be.

We did use different or later versions of codes and standards. We expanded the program, in some cases, to scope beyond GALL and in those cases we saw some exceptions there.

We did use later NRC guidance or precedents that we had seen from other licensees. And that resulted in some exceptions.

Because of our Unit 2 vessel issue, we did install an additional capsule there for the extended life so that we actually have a sample of all our weld material to look at once we get near the 60 year fluence. This particular capsule is located in a times three location, so that it will be seeing fluence a lot faster than the actual vessel.

The vessel internals program we have committed to in our application and in responses to RAIs that we will be looking at the EPRI program and we'll be submitting that program for review and approval once we'd looked at what EPRI is recommending, and will incorporate that into our program. And look for NRC approval some 24 months prior to period of extended operation.

And in the SER commitments area, you'll

see this data actually as a commitment.

Instrumentation circuits. We are using an alternate program here of cable testing. And in the case of medium voltage cable, we have already retested all of our medium voltage cable. And for all those inaccessible medium voltage cables. And the testing technique that we're using is one that we believe is successful. It's one that we can use while we're actually on line.

MR. SIEBER: So is it just a Megger test or--

MR. KNORR: No, it's not a Megger test. It's a -- Steve, you want to help me out here?

MR. SCHELLIN: It's partial discharge.

MR. KNORR: It's a partial discharge test.

MR. SIEBER: Tell me what that is.

MR. KNORR: Steven?

MR. SCHELLIN: The test is an inductive examination of the harmonics that reflect the partial discharge that may be present during the operability or during the operation of the actual cable.

MR. SIEBER: Thank you.

MR. ROSEN: Well, when you have a program to submit greater or equal to 24 months prior to the period of extended operation, and your period of

extended operation you enter in five years from now?

MR. KNORR: That's correct.

MR. ROSEN: What will you do if the reactor vessel internals program is not available in 2008, let's say? Do you have a backup plan? I mean, normally this question doesn't arise because people don't enter the period of extended operation period in as short a time as you will.

MR. KNORR: We're really no different than other licensees in this area. I think most of the commitments in the past have been identical of a program to be issued to the NRC for prior approval, 24 months prior.

MR. ROSEN: Yes, I understand your commitment's the same. But the timing is different in the sense that you will need it sooner than most other plants.

DR. SHACK: You're 24 months plus.

MR. KNORR: I understand. Okay.

I believe our indication that, you can help me out, Mr. Fromm here, that we're expecting EPRI to come up with the suggested programs by the end of next year, I understand, 2006.

MR. FROMM: This is Brad Fromm, NMC at Point Beach.

We are actively working with EPRI MRP and we're keeping a close eye on the Ginna plant. The Ginna plant has a very similar commitment and they are license expires a little sooner than ours.

MR. ROSEN: So you'll both in trouble then? Is there a backup plan? Will you develop your own program or is there --

MR. KNORR: I can't --

MR. ROSEN: What you use for EPRI is an instant.

MR. KNORR: I can't speculate, sir. I just don't know. I would suspect that we'd have to --

MR. SCHWEITZER: Yes, we need to take that for an action.

MR. KNORR: We'll have to take that for an action. We can get back to you.

MR. SCHWEITZER: To develop what we need to have for a contingency.

CHAIRMAN BONACA: I had a question about inaccessible medium-voltage cables. I thought from the application that you were only testing those in adverse environment?

MR. KNORR: That is correct. That's our commitment to do that into the future. However, we have tested all the cables, the inaccessible cables

and all the medium-voltage cables. Is that right, Steven?

MR. SCHELLIN: Yes. We did a baseline on all of the cables and our commitment in the future is to test a sample that's representative of all of the manufacturers and all the typical cable constructions that we have, but look at the cables that are in the most adverse environment.

CHAIRMAN BONACA: Now, since you're only testing some, do you have a plan of what you'll do if you find some degradation in some of them?

MR. SCHELLIN: We are developing that.

CHAIRMAN BONACA: In your sample?

MR. SCHELLIN: We are developing that, but it would be an expansion of testing.

CHAIRMAN BONACA: Still focusing on the ones in adverse environment or addressing all of them? I mean, GALL says you should test them all.

MR. KNORR: Well, we would expand the sample based on the testing that we've just completed. And if there's indication that it's more than just those in the adverse conditions, we would obviously go on to those cables that are outside of that population.

CHAIRMAN BONACA: What you are saying that

essentially you are going to not test those not in adverse environment unless you find one of them at some point failing? You're waiting for that to happen?

MR. KNORR: I think that's what I've just said.

Steven?

MR. SCHELLIN: We are going to test a sample of the cables in the adverse environment.

CHAIRMAN BONACA: Right.

MR. SCHELLIN: We tested all of the cables, many of which are accessible not underground. Those we do not see that they have a challenge to the cable because of their environment. But we will be testing a sampling of those that are underground inaccessible, exposed to water. Because we assume that if they're underground, they're exposed to water.

CHAIRMAN BONACA: Yes. I was reading somewhere in a inspection report where they found inadequate and untimely corrective action related to flooding of manholes containing safety and non-safety related cables. Have you corrected that deficiency?

MR. SCHELLIN: We are working on that problem. We have instituted two items at the current time. One is inspection and pumping of the manholes

on a periodic basis that depends upon the watering ingression into the manholes that started out on almost a daily basis and has gone to about once a week. And the second is we have a couple of engineers that are working on a water mitigation system and looking at a couple of options to try and dewater some of the manholes, which is a little bit difficult but they're working on it.

CHAIRMAN BONACA: Now of these cables are more important than others. So do you have also some strategic thinking about how you're going -- are you in selecting samples, for examples, you're saying that you're going to select a sample. Are you choosing the most -- since they're all in a challenging environment, are you just selecting on the basis of risk associated with losing that cable?

MR. SCHELLIN: We have a limited number of cables that are in a challenged environment. None of them are safety-related.

CHAIRMAN BONACA: Okay.

MR. SCHELLIN: They are, however, important to us economically because they are tied into our offsite power source. And those are the ones that we are testing.

CHAIRMAN BONACA: Okay.

MR. SCHELLIN: And for each phase we have multiple conductors for the phases, so the failure of a single conductor while a tragedy, will not take out the power for that phase.

CHAIRMAN BONACA: Thank you.

MR. KNORR: The next slide gives you an indication of where we are in effective full power years for both of the units. The reason that Unit 1 and Unit 2 are sort of a little odd to you, Unit 1 is the EFPY as of the last outage. We do the official calculations as of the last outage. As of today, as I said earlier, Unit 1 has been operating for almost a full year. So the actual number for this is 26.7, but that's the number that we had as of April last year when we had the outage for Unit 1.

Unit 2 is up to date, 26.2 is the expected full power years.

One of the things that we've done here at Point Beach for the numbers that you're seeing in our application, is we've assumed a 95 percent capacity factor. We believe that's a much higher capacity factor than most of the rest of the licensees have in the past. And, as you can see, for Unit 1 and Unit 2 the numbers are as 51 and 53 for the two units.

The capability factor, if you remember

right from an earlier slide, is more in the high 80's.

CHAIRMAN BONACA: You're referring to power uprate here?

MR. KNORR: Yes, we are. And really that has nothing to do with the EFPY. I think that's where you were going with that?

CHAIRMAN BONACA: No. My question on power uprate is that you made some statement in your application that you took consideration of the conditions of power uprate?

MR. KNORR: Absolutely.

CHAIRMAN BONACA: And for example, you concluded that scoping is not effected?

MR. KNORR: That's correct.

CHAIRMAN BONACA: What about steam dryers, just a question? I mean, how do you reach those conclusions that there was no effect? I mean, did you look at other power plants which have gone for an uprate or uprate and decided that, you know, they didn't experience any need for additional expansion of scoping, or did you draw those conclusions?

MR. KNORR: Well, our understanding is that, for instance, Ginna is going for a power uprate. And I think they came to the same conclusion there for their plant.

In our case, the steam generators in our case are designed for a much higher power level than we are now operating at.

CHAIRMAN BONACA: Yes.

MR. KNORR: All of the materials inside the steam generator are in scope. So there would not be any change by going to 1678 as opposed to 1540.

MR. SCHWEITZER: Is the answer, Jim, that we really looked at it and even with the thermal uprate that everything that we would need to be inspecting is already within the inspection correct?

MR. KNORR: That's correct.

MR. SCHWEITZER: The steam generator, the secondary side, the steam separators, the steam lines, heat exchangers are all within the program already.

MR. KNORR: Right.

MR. SCHWEITZER: So there was not additional inspections required by the thermal uprate.

CHAIRMAN BONACA: Yes. My raising the question with regard to the steam dryers was not accidental. What I mean is that, you know, for BWRs we saw that there was an issue there.

MR. KNORR: Yes.

CHAIRMAN BONACA: Of course, there was substantial power uprate. And then the result of it

is that, you know, it has been included as a component in the scope of license renewal.

MR. KNORR: In our case we had already included all of those materials. The structures, components that we had identified as being needed for power uprate had already been included in scope with our original scoping for license renewal.

CHAIRMAN BONACA: Okay.

MR. LEITCH: I meant to ask you when you were talking head replacement.

MR. KNORR: Yes?

MR. LEITCH: I read some issue that you had with respect to the polar crane being able to lift the new head.

MR. KNORR: Yes.

MR. LEITCH: Could you tell us a little bit about the resolution of that issue and was it a age related problem with the polar crane?

MR. KNORR: We actually had a phone conversation last week with one of the licensing reviewers who asked exactly those same questions. The--

MR. LEITCH: We didn't collaborate.

MR. KNORR: I understand that. I understand that. But that was good.

We were asked that same question as to whether or not there was any change in the current licensing basis, for instance, because of the head lift issues with the polar crane.

The new head is slightly heavier than the old head, but is still well within the capacity of our crane. There are no aging issues that are different because of this crane.

One of the issues that you have to look at for the crane is the number of lifts that you actually are allowed to make by the crane that might go beyond the capacity. And there are no plans to do any lifts beyond the capacity of the crane.

So our reviewer, at least the NRC's reviewer, appeared to be okay with our answers there. But we don't know of any issues from that head lift issue that have to do with the crane itself.

MR. SIEBER: Who is the manufacturer of the crane?

MR. KNORR: I'm afraid I don't know. Mark?

MR. ORTMAYER: It's Crane Manufacturing.

MR. SIEBER: Crane Manufacturing?

MR. ORTMAYER: Yes. Mark Ortmayer, NMC. It's CMS, Crane Manufacturing and Service

Corporation.

MR. SIEBER: Okay. Thanks.

MR. ORTMAYER: You're welcome.

MR. SCHWEITZER: Jim, maybe I could just provide a little bit clarification on our issue that we have right now.

It's not an issue with the crane itself. This goes back to NUREG-0612 control and lifting of heavy loads. And under phase 2 of the NUREG it required the licensees to be looking at load drop analysis, what would occur if you dropped head, do you have a single failure proof crane; a number of analysis.

Our crane is not single failure proof. We did a load drop analysis at that time, determined that there would be damage from dropping our head from the highest level. And we sent that into the NRC at that time.

There was no further follow-up at that time, but we did have it on the record back from 1982.

During the replacement of our new head questions came up about load drop analysis because the head is slightly heavier. We started to go back and research, and looked within our record. Determined that we did make this submittal back in 1982. So that

does become part of our licensing basis, although it was never reviewed and never incorporated into our FSAR. So it brought out the issue associated with whether we had an 10 CFR 50.73 echo issue in incorporating it into our FSAR.

We looked at that, and we believe that we needed a license amendment to incorporate it into our FSAR. And that's what we're working through with the NRC right now.

We have our own internal hold on the head until we resolve those issues. And the biggest thing we're working through right now is the '82 analysis was fairly simplistic and only went to the point of saying that from a static condition if you drop the head, your supports would fail. Therefore, you would have some significant damage to the direct coolant system piping. The analysis never went any further to truly quantify what that is, and that's what we're kind of working through right now.

We're looking at a long term analysis if we do a full, what's called a elastic-plastic analysis of the reactor coolant system, which I believe has only been done at one site. It's a about a three to four month analysis to step through that. So we're looking at other options right now in trying to come

up and do a better evaluation of the extend of the damage. And we're working with the staff here at NRR on that.

MR. LEITCH: So you're actually not lifting the new head until this issue is resolved, is that --

MR. SIEBER: They've got to.

MR. SCHWEITZER: That is correct, until it's resolved. It's an internal hold on it right now. But it's until the issues are resolved and we have agreement between NMC and Nuclear Regulatory Commission.

MR. LEITCH: Was that a critical path item right the moment?

MR. SCHWEITZER: Yes, it is.

MR. KNORR: Yes, it is.

MR. ROSEN: No, but you've already done that on one of the units, right?

MR. SCHWEITZER: No. We've not replaced a head.

MR. ROSEN: Oh, I thought you had already replaced one.

MR. SCHWEITZER: Unit 2 in the refueling outage right now is the first replacement.

MR. ROSEN: Okay.

MR. SCHWEITZER: Unit 1 will be in the fall.

DR. SHACK: What changes will you make for the uprate?

MR. KNORR: For the reactor vessel head?

DR. SHACK: No, for the power uprate?

MR. KNORR: We will be doing -- the major changes we're going to be making is in the case of main feed pumps, we need more capacity. So we'll have to replace our main feed pumps.

The high pressure turbine is another area that we will have to make some changes and have to go to a slightly larger -- or different design of high pressure turbine.

Those are the major changes that we're going to be making. I don't --

DR. SHACK: Will that change T_{hot}?

MR. SIEBER: It probably will.

MR. KNORR: I believe slightly, yes.

MR. SCHWEITZER: Yes. There is a slight increase of T_{hot}.

MR. SIEBER: If you don't change the coolant pumps, something's got to go up.

MR. KNORR: Yes. And we will be -- and those differences in temperature have been

incorporated into our evaluation of aging within the reactor itself and steam generators.

MR. SIEBER: Well, you're relatively low temperature right now. You've got probably 8 of 9 degrees to go before you get into the exciting range.

MR. ROSEN: When you say you're going to raise T_{hot} a slight increase, are you talking about the 8 or 9 degrees or less than that?

MR. SCHWEITZER: I don't know the number right off.

MR. SIEBER: It's probably less than that.

MR. SCHWEITZER: I don't think it's quite that high, but I don't have that number on the tip of my tongue at this time.

MR. KNORR: I don't either.

MR. ROSEN: Well, it affects my feelings about longevity of steam generators. It's very sensitive to T_{hot}.

MR. KNORR: Okay. We can get that piece of information and get back to you with the exact temperature. I'd rather do that than speculating on what it is.

MR. SIEBER: What's the percentage of power increase that you're thinking about?

CHAIRMAN BONACA: Eight point seven.

MR. KNORR: It's a little bit greater than 10 percent, sir.

MR. SIEBER: Okay. So that's going to be a ten percent increase in delta T. That tells you what the temperature is going to be.

MR. ROSEN: If I knew the delta T.

CHAIRMAN BONACA: I thought you already -- the 1.7 percent?

MR. SCHWEITZER: We've also -- that's from the leading edge flow meter from the feed flow. So we've realized some of that percentage already.

CHAIRMAN BONACA: Okay. And the rest is about nine percent or eight percent?

MR. KNORR: It's about nine percent, that's correct.

CHAIRMAN BONACA: Yes. It can't be that much in temperature.

MR. KNORR: The next slide I have here it talks about pressurized thermal shock and upper shelf energy. We can either have the discussion now, and I do understand that the staff also has a discussion of these particular items. If you would like to have the discussion now, we can do that.

What I gave here is a little bit more detailed than the staff's provided. But what I do

want to tell you is that, again, we assumed 95 percent capacity factor and that full power uprate, 1578 megawatts thermal so that the numbers you see here are assuming those things happening.

In the case of upper shelf energy we're slightly less than 40 foot pounds. But in both units' cases, when you do the equivalent margins analysis, we do come in at greater than one, which is the acceptance criteria.

In the case of Unit 1 for RT_{PTS}, we are at 299, which is under the 300 degrees criteria. But in the case of Unit 2 we do have one weld that is greater than 300 degrees at 60 years. And though we did provide to the staff as well the years that we would be able to operate, which is 38 -- a little over 38 effective full power years, which is approximately the year 2017.

Now, the key here is the note that I have at the bottom. About three years prior to that the rule requires that we do one of two things. We either come up with an analysis for and the criteria for a fluence control program where flux reduction is our goal so that prevent PTS from happening at the plant or we license an alternate PTS analysis technique which is the master curve is one option that we have.

In either case three years prior to it in accordance with 50.61, we have to go to the NRC with that program and get approval.

CHAIRMAN BONACA: We can discuss this when the staff makes it presentation.

MR. KNORR: Okay.

CHAIRMAN BONACA: However, I would like just a clarification to understanding where you're going. I mean, in the application you spoke of a master curve.

MR. KNORR: That's correct.

CHAIRMAN BONACA: And they usually approach, and I really don't know enough about it, I would like to know more about that.

Now then you had a submittal later on that said we're not going to do that. We're going to manage aging by monitoring fluence and then do the second that you're saying here.

MR. KNORR: Correct.

CHAIRMAN BONACA: I was confused about which path you're going to take. Now you mentioned again the possibility of using the master curve at a later time.

MR. KNORR: That's correct.

CHAIRMAN BONACA: And so I'm confused

about what you want to do, and I would like to know from you what the actions are. So, I mean, I know in the meantime there is going to be probably a new PTS rule which is not as restrictive as the current one.

MR. KNORR: Yes.

CHAIRMAN BONACA: Are you planning to take advantage of that? I would like to understand your strategy.

MR. KNORR: If we had our druthers, we would like to take advantage of the new rule. Because our understanding is that the acceptance criteria under the new rule is more in the 325 degrees range. And that's just an estimate that I've heard.

In the case of master curve, using the actual fracture toughness measurements as opposed to the correlation to Charpy V-notch, we believe that the generic report put together by B&W, B&W 2308 Rev. 1 would result in an actual RT_{PTS} for us in the 292 to 295 range.

CHAIRMAN BONACA: Then why don't you us that?

MR. KNORR: The reason why is because when we supplied our license renewal application to the staff, the generic report put together by B&W was not yet approved. And so what we were doing is we were

relying on an unapproved report at that point. And so we thought the best option for us was to just withdraw that application and then go to -- the program that we're doing and then leave that as an option to use the master curve something later.

Again, so our backup here is the ideal would be to use a revised rule. And the backup to that would be the B&W-2308 option or master curve. And, obviously, if none of those work we still have the option of some other flux reduction programs that we can go in. Okay?

MR. ROSEN: Now how this hafnium business relate to that. Hafnium is suppression of flux. And I understand from reading the application that you're going away from that?

MR. KNORR: In the application we said that we were going away from that. However, we have made a commitment since then as part of this discussion of master curve and going to a program where we would say we're going to maintain hafnium in there until we come up with either another flux reduction program or go ahead with master curve or one of the other options.

MR. SIEBER: I presume you're using low leakage cores?

MR. KNORR: That is correct.

MR. SIEBER: And have been for a long time?

MR. KNORR: For along time, sir. That's correct.

MR. SIEBER: All right.

MR. ROSEN: Is somebody going to pull all this together for us? Is the staff going to talk about this?

MR. SUBER: Yes, I think the staff has a presentation.

MR. ROSEN: All right. We'll wait for that.

MR. KNORR: Okay.

MR. SIEBER: Okay. Thanks.

MR. KNORR: Earlier in the discussion this afternoon during current operation discussion with Mr. Louden, one of the concerns that the Committee had was on commitment management. And what I wanted to do is just to go over our program at Point Beach to give you an idea of what we do at Point Beach.

First off, all of our commitments come from one of two locations; either the original application or they come from a request for additional information response that we have submitted. And each

of these commitments are actually on cover letters that are sent into the NRC.

Also, you'll find at the end of the SER that was written by the staff a listing of all of these commitments. Each and every one of these commitments have been entered into our regulatory information system, which is our commitment management program and system. It is a software package that tracks each and every one commitment that is made at Point Beach. Not only license renewal, but all other kinds of commitments as well.

In license renewal we realize as part of our programs we're going to have to institute and have control over all the changes being made to various procedures, processes, etcetera, at the plant. And we have also instituted a software package that interfaces with the regulatory information system by capturing all of those commitments as well as items that we have required in each of our programs that are not in the commitment system, but also our -- I'm going to use the word small "c" commitments within the program to make sure that we change whatever procedures are there to provide activities to manage the aging of the plant.

And those two populations of items will be

issued or put into our corrective action program, which at Point Beach and at the NMC, is our Team-Track corrective action program.

Now, obviously, all of those items that are in Team-Track are going to be tracked with due dates to make sure that they're complete by a certain date. In our case, a lot of them are prior to the period of extended operation. However, the way our program is set up and the way my project is set up at Point Beach is that we are going to keep our group primarily intact as the license renewal team, even after we get our license -- and I hope we get our license from your suggestions. In 2006 we will keep them here and we will keep them working on the implementation. And so a lot of the dates, even though they might out in the 2010 time frame, we're going to see a lot of that completed before the end of 2006. And we'll actually implement all of those programs at that point.

MR. ROSEN: Well, I think you said a reassuring thing there, is that -- but I want to be sure I understand it. Is that your team is staying together. And that the commitments you make are going to become an ongoing implementation activity between, let's say, the end of this year and 2010?

MR. KNORR: Yes, that's correct.

MR. ROSEN: And so you're not going to wait until the last moment and then to try to start to implement all of these?

MR. KNORR: No, that's doesn't make sense, sir. Two things.

One is I think aging management is a good thing to do now. And the other is that the project is set up such that we will get a lot of that work done before we disband. And, obviously, there will be a license renewal presence beyond the end of 2006 as well which will actually manage this as well.

MR. ROSEN: So the procedures that implement the license renewal commitments will be changed in relative near term and you'll beginning implementing them to kind of, as you roll forward?

MR. KNORR: Right. Our objective is to get all those procedures marked up by the end of 2006. And a lot of them already implemented during 2006. But additional ones may have to go beyond that. And we'll just implement them whenever the next revision change is made of a particular procedure.

One more slide here on the corrective action program. It's integral to our commitments. It's a common process across the fleet, which I just

mentioned, the Team-Track system that's actually implementing all of these. And that's the tracking system to make sure that all of this stuff is done.

The corrective action program is an item that is taken out for each and everyone of these commitments. And there are actually corrective action items which are owned, by the way, by either a manager of a particular department or by a manager within the license renewal group. And the corrective actions have to be completed before we can close the corrective action program item. So a little complexity there, but it helps us control our commitments as we go on.

One of the things that I want to make sure you understand is that this Team-Track item is also an integrated portion of work control process. We have a computerized history and maintenance planning system which tracks all of our call ups, which are the short term kinds of periodic testing and things that we do, inspections and so forth. And so the integration between these two programs is going to help us make sure that we get done what needs to be done to implement our aging management programs.

Finally, this is just a review of some of the things.

We did base our application on a 2003

template, and we talked about that earlier. And the NRC review was divided into two areas; one is it consistent with GALL audit process and then also a review by the staff itself.

The safety evaluation report that you've all read through, I'm sure, in detail was all based on the standard review plan. And, frankly, our application and the standard review plan are mirrors of each other. So I'm hoping that made it a little easier for the staff to go through that review and actually generate the SER.

So any other questions we might have from the ACRS? That pretty much concludes my remarks.

CHAIRMAN BONACA: I have a number of questions.

One is a one-time inspection of small bore piping.

MR. KNORR: Yes.

CHAIRMAN BONACA: Due to the position that you have a risk-informed ISI program and that would suffice?

MR. KNORR: Yes. That's correct.

CHAIRMAN BONACA: I remember that GALL required that you inspect one-time inspection of susceptible area irrespective of risk. And so I was

kind of confused.

MR. LEE: This is Sam Lee from License Renewal Branch.

The GALL basically says you need to do a sample inspection for small bore piping, okay? In this case about risk-informed ISI, they already doing inspection for small bore piping because of risk. So they already including a sample of small bore piping in the ISI program.

CHAIRMAN BONACA: I understand that. I thought that the objective, however, was to inspect the most susceptible area irrespective of risk? Because I mean, you wanted to see if that -- there was some aging effect associated with small bore piping in some susceptible locations and draw some conclusions from it. And that, if I remember, was the position that was taken even in GALL.

MR. LEE: I think to the risk-informed ISI, I think they incorporated I guess the experience of the -- what critical locations based on experience. I think that's factored into the ISI program.

MR. KNORR: You speaking of the NUREG-6260, the locations.

MR. LEE: Yes.

MR. KNORR: The locations? Yes, correct,

those are part.

MR. ROSEN: I think this is an issue that's come up before where we've talked about coherence of the regulatory program where on one hand the staff accepts the risk-informed ISI program and the other hand, it doesn't accept it in the license renewal space. And I think there is still some remaining, if not inconsistency, between those two positions, at least confusion in my mind.

CHAIRMAN BONACA: But, see, the one-time inspection in fact is intended to confirm that something is not happening. I mean, that is the thing, it is not to find what the problem is but to confirm the conclusion that, you know, small bore piping is not affected by aging problems. And so for that purpose, if I remember clearly, that in other applications we made a case that you would be looking in susceptible locations. If you look in susceptible locations and you don't see anything, you conclude that in fact your consideration is appropriate, there isn't -- in fact, you don't need to look any further. One-time inspection is adequate. If you don't look with that kind of criterion, you cannot conclude that you will have not have the aging effect happening.

MR. CHANG: This is Ken Chang License

Renewal Section Branch.

In a couple of the telephone discussions held with the applicant we reviewed their program before. And risk-informed ISI was used for the small bore piping. And we asked about the locations being selected to do the inspection. And although my memory was not good, I think that was in the order of 30 to 40 locations inspected. That's way above the normal applicants inspected. So we are happy with that response.

Now, the applicant may to give the precise number of locations, because I only remember 30 or 40.

MR. KNORR: Mr. Thorgersen, you have a --

MR. THORGERSEN: I guess. This is John Thorgersen from the Nuclear Management Company.

A couple of points. One is that the risk-informed ISI methodology does include operating experience and takes into account the aging effects in mechanisms that have been seen in the industry in the piping that falls within the scope of the risk-informed ISI program.

CHAIRMAN BONACA: So you're looking also for susceptible locations?

MR. THORGERSEN: Yes.

CHAIRMAN BONACA: Okay.

MR. THORGERSEN: And as far as the exact number, I also remember that phone conversation. And I'm struggling with my memory also.

Brad, do you remember exactly how many locations it was? It was around 30 that we were talking about.

MR. LEE: I think the ACRS is looking to say are you inspecting one or two or ten or 20 or 30. It's not in the 37 or 35. What I'm trying to explain is there are plenty of locations being selected for performing the inspection.

CHAIRMAN BONACA: Now I think you are guessing what the ACRS is asking about. Because, I mean, where in the intent of one-time inspection, always one confirming that something is not happening.

MR. LEE: Yes. It has always --

CHAIRMAN BONACA: In the beginning we had discussions here, I can go back to records, where I was told by the staff that, yes, in fact we want to make sure that they're looking at some susceptible location to confirm that the effect is not happening, then you can draw those conclusions about the risk analysis, you don't have to do any further inspections.

If you only do risk-informed, you don't

look necessarily in a susceptible location, therefore you cannot draw the conclusion that you can depend on the one-time inspection. That was really the basis until now.

Now, the answer from the licensee is appropriate. And it says, yes, we're looking at susceptible location and that's the appropriate answer. But I think in general when you look at these programs, you can't change -- I'll go back to some records we have completed the application and put out those things.

I do not understand position that you took on IGA/IGSCC on austenitic stainless steel. You talk about 140 degrees Fahrenheit threshold. But then say that -- it's let's see now, and then you say that this credible effect for welds due to the controls that you have on those welds, okay. And then at some point there is a discussion of susceptibility that may be increased by prolonged exposure to temperature higher than 482 degrees Fahrenheit. I am confused about the position you took on IGA/IGSCC on austenitic stainless steel. Would you explain what the position is? Are you going to perform inspections there or are you telling me that you have no susceptible material and therefore you're not inspection at all. I don't

understand?

MR. KNORR: I'm afraid I don't know the answer to that, sir. Brad, can you help us with this or Doug?

CHAIRMAN BONACA: Yes. The position you took on the application on the IGA/IGSCC austenitic stainless steel, it's somewhat confusing. You came to the conclusion that you have not susceptible material, therefore you will not perform inspections to that. And then there is a discussion that speaks of -- ability could be increased by prolonged exposure to temperate higher that 482 degrees Fahrenheit. And you acknowledge that you have some materials in that condition. I would have to go back to the application now and see the exact location.

MR. FROMM: We would have to go back to the application.

CHAIRMAN BONACA: Are you checking that?

DR. SHACK: I'm still searching through the 1274 pages.

MR. KNORR: I'm sorry.

MR. COZENS: This is Kurt Cozens from the NRC staff License Renewal.

Are you inquiring whether you applied this to CASS materials or are we talking both about

SSC plus thermal aging?

CHAIRMAN BONACA: This was in a discussion of austenitic stainless steel.

MR. COZENS: Because I know CASS, 140 degrees is indeed the threshold that we apply in GALL to the stress cracking. And the 148 degrees, my recollection, it may be a little fuzzy, but I was thinking that was for thermal aging. And I thought that only applied to CASS.

DR. SHACK: Yes. This doesn't make a whole lot of sense.

CHAIRMAN BONACA: That's right. I mean I was confused by the write up.

MR. COZENS: If we could identify --

DR. SHACK: You're sort of confusing the embrittlement of CASS stainless with a IGA/IGSCC susceptibility.

MR. COZENS: There could be a write-up there. It's maybe not worded well. We'll have to look at it.

DR. SHACK: Well, no. I take it back. The threshold temperature of 140 is not a credible one --

CHAIRMAN BONACA: Bill, could you speak in the microphone.

DR. SHACK: -- temperature which limited--

boundaries to this aging at the heat effected zones -- I'd be a little surprised with a high carbon stainless steel their welding was really all that successful to do that.

CHAIRMAN BONACA: Anyway. Okay. So you found it?

DR. SHACK: Yes. Right.

MR. ROSEN: What's the reference to that?

DR. SHACK: 3.0.1.4.4.

MR. KNORR: That's obviously a further review required recommendation in 201 of the GALL. That's RSP question, I presume.

DR. SHACK: I mean, you might have a much better argument over the chemistries to which these welds are imposed. Boy, I mean, I'd have a hard time buying one that your welding was careful enough to prevent sensitization in an ordinary stainless steel.

MR. KNORR: Any comments?

CHAIRMAN BONACA: Okay. That's my question. I have other questions to the staff later on.

MR. SIEBER: I'd like to ask one question before we have the break and the licensee disappears.

MR. KNORR: We're not to disappear.

MR. SIEBER: I read someplace where you

had containment liner corrosion from boric acid.

MR. KNORR: Yes.

MR. SIEBER: I'm curious as to how you got it, because container liner is supposed to be painted. And reactor coolant when it leaks out, comes out as steam. But by the time it hits the liner, it typically will dry out unless the leak has been there for an awful long time and the protective coating is defective. Otherwise you get a pile of boric acid crystals, and I'm sure curious as to how you got -- you know, the regular boric acid corrosion rate is 140 degrees, which is typical of containment.

MR. KNORR: Right.

MR. SIEBER: It is not big. And I'm wondering how you would have a lot of degradation?

MR. KNORR: I'm going to let Mark Ortmayer answer that question. He's been looking at the liner. So, Mark?

MR. ORTMAYER: Mark Ortmayer, NMC.

I think that's in referring to a boric acid water that was leaked onto the containment floor. So it's borated primary water leaked out. We had some flooding issues.

MR. SIEBER: Did it come out of the coolant system up out of the makeup system?

MR. ORTMAYER: It would be part of the primary coolant system.

MR. SIEBER: So it's --

MR. ORTMAYER: Refueling water.

MR. ROSEN: Well, no during shutdown.

MR. ORTMAYER: During shutdown. Yes.

MR. SIEBER: You know, it's not active.

MR. ROSEN: It depends how much you dump. I mean, it sounds like it was wet.

MR. SIEBER: I mean, if it's hip boots in there, I would think somebody would do something about it.

MR. ORTMAYER: This was we had some operating experience. These were some events that had happened. I think the early '90s where we had these issues.

MR. SIEBER: Well, it sounds like -- my picture of it is that it was a hip-boots-and-umbrellas kind of a deal inside containment, which is really at a standard less than what I'm used to.

MR. SCHWEITZER: Mark, is this at the interface between the lower elevation of containment at the floor the containment wall liner where we've had some back leakage out of our RHR suction line from containment?

MR. SIEBER: That could be.

MR. SCHWEITZER: We had some boric acid water, cool water get on the floor, get on the interface between the concrete and the liner wall.

MR. SIEBER: How do you do that? You have to penetrate the liner to get there, right?

MR. SCHWEITZER: No. Our liner is a --

MR. SIEBER: It's welded, right.

MR. SCHWEITZER: Yes. Internal containment. Okay. In the lower elevation --

MR. SIEBER: Yes, I used to work in a plant like that.

MR. SCHWEITZER: At the lower elevation it goes down below the concrete floor.

MR. SIEBER: I understand it. Yes.

MR. SCHWEITZER: We had enough water on the floor there.

MR. SIEBER: I worked in a plant just like yours.

MR. ORTMAYER: That's right. There's expansion cracks or control pores in the floor of the concrete. And also along the perimeter. And if those seals leak, then you could get borated water between the concrete and the liner plate.

MR. SIEBER: Okay.

MR. SCHELLIN: This is Steve Schellin.

But it's not at 140 degrees at that point. It's at containment ambient, which is less 105. Probably much less once it's on the concrete.

MR. SIEBER: Maybe that's true. I remember it being real hot in there during operation.

MR. KNORR: Thank you, Mike.

Any other questions?

CHAIRMAN BONACA: If none --

MR. MIELKE: This is Todd Mielke, NMC.

We may have a couple of answers for you on the power uprate. And I was wondering -- what we're looking at here is some numbers out of a technical report that we have put together by the Westinghouse analysis our vessel outlet T_{hot} operating conditions is a maximum of 605.5. So we would operate less than that.

Does that answer the question?

MR. SIEBER: Yes, it does.

CHAIRMAN BONACA: Thank you. Other questions? If none, I think we'll take a break now.

We thank you for the presentation. And we'll break until ten after three.

(Whereupon, at 2:54 p.m. a recess until 3:12 p.m.)

CHAIRMAN BONACA: Okay, let's get back into session. Now we have the presentation by the staff of the SER with open items for License Renewal of Point Beach and we've got Planning Units One and Two.

MS. RODRIGUEZ: May I proceed?

CHAIRMAN BONACA: Yes, please.

MS. RODRIGUEZ: Good afternoon. My name is Veronica Rodriguez, Project Manager within License Renewal. I'm here today to present the SER with open items for the Point Beach Nuclear Planning Units One and Two.

As you all know, the safety evaluation has been a huge team effort. Along with me, I have two other Project Managers working on the project. Mr. Michael Morgan, here on my right. He's going to be helping me with the computer. And Mr. Gregory Suber, on my left, over there, who's going to be doing the presentation on Section Four and TLAAs.

In addition, I have here on my left, Mr. Kurt Cozens who's the Project Team Leader for the Audit Team, and he's going to be helping me with Section 3.0 and the descriptions on Aging Management Programs and the Audit Findings. Also, Patricia Lougheed, Team Leader for the Regional Inspection, is

going to be presenting the findings. Most importantly, I would like to recognize the presence of the Staff Reviewers who are seated in the audience. They will be helping me with your questions.

Before we get started, I would like to point out that we have a lot of information to cover in the presentation. I'm going to go pretty fast, so please feel free to stop me at any time if you have questions. Next slide.

Okay. As the applicant previously said, Point Beach is a two-unit PWR located in the east center of Wisconsin, on the west shore of Lake Michigan. On February 25, 2004, the licensee requested a 20-year license extension. The Unit One current license expires in October 2010. The Unit Two expires on March 8, 2013. The SEI with open and confirmatory items was issued on May 2, 2005. It has five open items --

MR. LEITCH: There's also an Inspection Report that was issued May 2, 2005.

MS. RODRIGUEZ: That's correct.

MR. LEITCH: And I was wondering if the SER includes the items surfaced -- in other words, which one came first, they were both issued the same date.

MS. RODRIGUEZ: Yeah, they were both issued on the same date. And we're going to cover the inspection findings after this Section 3.0.

MR. LEITCH: But they're not incorporated in the SER?

MS. RODRIGUEZ: No, it's a separate Inspection Report.

MR. LEITCH: Okay.

DR. KRESS: How close is Milwaukee?

MS. RODRIGUEZ: I'm sorry?

DR. KRESS: How close is Milwaukee to the plants?

MS. RODRIGUEZ: I don't know.

MR. COZENS: What, about a hundred miles, Jim?

DR. KRESS: Sixty. A good distance away.

MS. RODRIGUEZ: Okay. The SER has five open items which we are going to discuss later during the presentation. Two of them are related to agent management programs and three of them are related to agent management reviews. It also has 15 confirmatory items and three license conditions which are the same license conditions that you have seen in previous applications.

On this slide, you can see a list of the

audits, site visits and inspections that were performed. One that I would like to point out is this is the first time that we have performed a combined regional inspection on scooping, screening and AMPs. It was 3-weeks of inspections; two weeks were on site, one week was on the regional offices and it began on March 7, 2005.

Moving forward with Section 2.1, Scoping and Screening Methodology. Like I previously showed you, the onsite audit was performed during the week of June 21, 2004. The SAG had several RAIs. The three RAIs are currently confirmatory items. The first one relates to exposure duration term. The second one was first equivalent anchor. And the third one, flow-accelerated corrosion effects on (a)(2) piping.

CHAIRMAN BONACA: So on the first one, have we clarified what it means long-term versus short-term exposure?

MS. RODRIGUEZ: Yes, I'm going to talk about the first one a little bit more. Please go to the next slide, Mike.

CHAIRMAN BONACA: Okay.

MS. RODRIGUEZ: On this first confirmatory item, the staff was concerned with the short-term exposure duration because it was not adequately

defined on the NRA.

On April 29, 2005 we received a letter from the applicant changing their methodology. This information, you don't see it in the draft SER because it was received after the cutoff date of the SER, which was March 31st. In this letter, the applicant removed the term "exposure duration." They are no longer using that. They have changed their methodology and they're invoking now a new spaces approach which assumes a special interaction can occur if non-sanctioned components and safety related components are within the same space.

This letter expands the scope. System boundaries have been extended and the applicant had identified 14 new component types within the scope of license renewal. However, no new aging effects mechanisms were identified.

CHAIRMAN BONACA: But the scope is quite changed. I know in the Audit Report, a number of statements by the auditors were that they could not really verify the boundary because the boundary was invisible, right?

MS. RODRIGUEZ: Yes, correct. All this information is on their staff review and all of this is going to be documented in the final EAR.

CHAIRMAN BONACA: Okay, so the final SER will have --

MS. RODRIGUEZ: That's correct, will have more information.

CHAIRMAN BONACA: It will have -- we will see probably more components and scope on some of them.

MS. RODRIGUEZ: Yes, that's correct.

CHAIRMAN BONACA: Okay. All right.

MS. RODRIGUEZ: Next slide, please.

MR. LEITCH: In the License Renewal Application, the applicant states that mitigative, non-safety related SSCs can be excluded from the scope if the function is maintained. I'm not sure I fully understand that. Does it mean that, for example, if a piece of piping could drop on a diesel and take a diesel out of service, so long as the diesel -- there was another diesel that that piece of piping then need not need be in scope. Is that what's meant by that, or perhaps I don't understand what's meant by "mitigative."

MS. RODRIGUEZ: Right now, what they're doing with this new methodology is if the non-safety related pipe was within the same space as the safety related pipe, all of them are going to be within the

scope of license renewal.

MR. LEITCH: Within the same space?

MS. RODRIGUEZ: Yes.

MR. LEITCH: So in my example, --

MS. RODRIGUEZ: If it breaks a pipe, and it's going to affect the safety related function, it's going to be within the scope.

MR. LEITCH: Even though the function is maintained with another completely separate system?

MS. RODRIGUEZ: If it's going to affect it, it's going to be within the scope.

MR. LEITCH: Okay. Well, what is meant by "mitigative?" Could you give me an example of the mitigative function then?

MS. RODRIGUEZ: I'm going to call Mr. Rich McIntyre to give us a couple of examples. Rich?

MR. SUBER: This is Greg Suber. Actually, I believe that would be Chang Lee.

MR. COZENS: People have come and gone, apparently, today.

MR. GALLETTI: This is Greg Galletti from the staff. I think what you're reading there is a general motherhood statement that we've seen in the past and what they're trying to reflect is a discussion of the regulation, 10 CFR 50.54(a)(2) which

says, "... if a non-safety related component can cause a failure of a safety related component from performing its intended function." So what they're trying to get at there is that if the intended function of the component is not -- I'll use the word "failed," then that non-safety related component would not have to be brought into scope. So, in other words, if you had a safety related component that performs an intended function, you had a failure of a non-safety related component, but that failure did not render the safety related component's ability to perform its intended function from happening, then that other component would not have to be brought into scope.

MR. LEITCH: Okay, I understand. Thank you.

MS. RODRIGUEZ: Okay. Like I previously said, all this information is currently under staff review and will be documented in the final SER.

Section 2.4. Scoping and screening of containment structures and support. The staff evaluated the LRA to determine any passive and long-lived SSCs required to be within the scope of license renewal were omitted. The staff found no omissions; however, we haven't identified one confirmatory item

in where the applicant needs to specifically identify which concrete tank foundations are within the scope of license renewal.

Section 2.2, 2.3, and 2.5, Scoping and Screening of Plant Level, Mechanical Systems, Electrical Instrumental and Controls. Again, the staff reviewed the NRAs to determine if any SSCs required to be within the scope of license renewal were omitted. No omissions, no open items and no confirmatory items were identified.

This concludes our presentation of Section Two. I want to move forward with Section Three.

MR. LEITCH: I had a couple other questions about Two.

MS. RODRIGUEZ: Sure.

MR. LEITCH: There's a couple of -- well, I guess there was a revision to the License Renewal Application. Most of the applicable sections were changed, but there are some pieces of the License Renewal Application that appear as though they need to be changed that are now in conflict with the revision, I think. But I'm confused by them. For example, Page 2-32 --

MS. RODRIGUEZ: Of the SER?

MR. LEITCH: No, of the License Renewal

Application. There's some discussion there about the PTS TLAA, that says it's addressed in 4.2.1, but by retro of the renewal, or the revision to the License Renewal Application, that seems like that paragraph, that comment is no longer valid. It appears to contradict the revision.

MS. RODRIGUEZ: The PTSR is still addressing Section 4.

MR. LEITCH: Excuse me?

MS. RODRIGUEZ: PTS is still addressing Section 4.

MR. LEITCH: Yeah, but the comment that the PTS TLAA is addressed in 4.2.1, the PTS TLAA is not really addressed in that section anymore. It's not a TLAA change for that.

MS. RODRIGUEZ: I don't understand. I think PTS is still described in Section 4.2, correct?

MR. COZENS: Are you addressing the fact that if they use the current regulatory structures that you don't do an analysis per se?

MR. LEITCH: Yeah.

MR. COZENS: And you wait for the regulatory structure to take the lead?

MR. LEITCH: Right.

MR. COZENS: Versus justifying continued

operations once you exceed a screening criteria?

MR. LEITCH: Right.

MR. COZENS: I think that's something you might want to look at.

MS. RODRIGUEZ: Okay. We can do that.

MR. LEITCH: Also, I think on Page 1.3 of the License Renewal Application, there are some statements made there that appear now to be in conflict with the revision to the License Renewal Application.

MR. COZENS: Which pages were those?

MR. LEITCH: Page 1.3, the first paragraph, 1-3, the first paragraph.

MS. RODRIGUEZ: Okay. I'm making a note. Shall we continue?

DR. WALLIS: While we're on this slide, I noticed that the applicant made many commitments, I think there in one of the appendices?

MS. RODRIGUEZ: Yes, that's correct.

DR. WALLIS: -- to enhance these programs or develop programs, a whole list of programs to be enhanced or developed or some other term like that. And this gives the impression that a great deal of work needs to be done to improve these programs.

MR. COZENS: We have a slide on that.

DR. WALLIS: When is it that it's actually checked that these really are improved up to the required standard and how is it done and why isn't it done before license renewal?

MS. RODRIGUEZ: Some of these programs are not still implemented and before --

DR. WALLIS: How do we know they're going to be implemented? It's just some sort of commitment for the future.

MR. COZENS: The slide after this one, I believe, is where I start and I believe that's the first slide to talk about that.

DR. WALLIS: And you're going to tell us all about this?

MR. COZENS: I'm going to talk to it, yes.

DR. WALLIS: But isn't this -- when is it that someone says these commitments have been suitably fulfilled?

MS. RODRIGUEZ: Before the period of extended operation --

DR. WALLIS: So there's another check there --

MS. RODRIGUEZ: -- we do perform inspections --

DR. WALLIS: -- where you do a very

thorough inspection --

MS. RODRIGUEZ: -- to make sure they are implementing the commitments.

DR. WALLIS: That's when we know that these commitments were fulfilled?

MS. RODRIGUEZ: I'm going to let Patricia --

DR. WALLIS: That would seem to be a very important part of this whole process.

MS. RODRIGUEZ: Yes.

DR. LEE: This is Sam Lee. I guess you're looking at Appendix 8, that's the Commitment List?

DR. WALLIS: Right.

DR. LEE: That will actually be taken out and put into the inspection -- I guess, the IP 71.0 --

DR. WALLIS: Well, it seems to be just as important as what you've been doing in this report.

DR. LEE: Right now, the inspector inspects the programs that are in place. So, if the Appendix say that those ones are not in place, then they will do it before Year 40. Then we also have the license condition on the license to make sure that this is carried out and that they'll inform us when the commitments are completed. And then the (inaudible 3:26:52) will go out. So you have what

they said in some of these programs. In this case, they actually put them in place before 2006. If they do all that, they'll tell us in 2006 and then the Regional Inspector can go out and check.

DR. WALLIS: And the ACRS doesn't look at that? So we're sort of taking it on faith that you're going to do this job right?

MS. RODRIGUEZ: Well, all these commitments become part of the license basis and the region performs inspections to make sure they're implementing correctly.

DR. WALLIS: It just concerns me that we're being asked to sign off on something which has a whole lot of commitments and we don't have any checks on how well these commitments are fulfilled.

CHAIRMAN BONACA: Agreed. That's why we raised this question at the beginning of the meeting with regard to the current ROP condition of the licensee and what does it say about these promises that we have right now. We have a lot of promises and we don't have enough verification. The verification will happen at another time and we think an applicable comment to be what do you need to do at that time to verify that, in fact, the commitments are being implemented. So that's an issue.

MR. ROSEN: Of course, there is no bar on us having a subcommittee meeting and asking for the staff to come back and tell us as long as we remember to ask.

DR. WALLIS: Well, maybe with some of these license renewals, if we have a memory that long, we may want to --

MR. ROSEN: This may be the right one because we only have to remember for two years.

(LAUGHTER.)

MR. ROSEN: We don't have to remember for 20 years. Some of us may still be on the Committee.

DR. WALLIS: That's a good point.

MR. SIEBER: We need a commitment control system.

MS. RODRIGUEZ: Okay, let's move on. Section Three, Aging Management Review Results. This slide shows you how Section Three is organized. It has seven sections. Next slide.

Section 3.0, the applicant's use of the GALL Report. The applicant had identified a total of 26 Aging Management Programs, 21 of those are existing programs, five are new programs. Twenty-two programs are consistent with the GALL risk assessments or enhancements and four are plant specific programs or

programs not consistent with the GALL. In Section 3.0, the staff has identified two open items and two confirmatory items related to the Aging Management Programs. With this, I would like to turn the presentation over to Mr. Kurt Cozens, Project Team Leader for the Audit. He'll be presenting selected AMPs and the audit findings.

DR. WALLIS: I'm sorry, on Page 9 you talk about the number of programs.

MS. RODRIGUEZ: Yes.

DR. WALLIS: Well, the student answered 26 questions, but how well did he do?

MS. RODRIGUEZ: Kurt is going to talk about that.

DR. WALLIS: You're going to tell us how well these programs are managed?

MR. COZENS: What I am going to tell you is whether or not they satisfied the criteria of 54.21(a)(3), which is to develop a program that is capable of managing aging affects such as the (inaudible 3:30:09) --

DR. WALLIS: Another concern I have is the existence of a program doesn't tell me anything about how good it is.

MR. COZENS: You are correct. At this

point in time, we are approving the program. It is the responsibility of the region to perform inspections just as if it was for any other program commitment that an applicant might make, whether it be for licensing or something else for operations, that the region has the responsibility for reviewing whether or not that commitment is adequately implemented. It is the same case here.

DR. WALLIS: So this is another part of the license renewal process, is this reliance on the region to do a thorough job of looking at the programs?

MR. COZENS: Oh, absolutely. Absolutely.

MR. SIEBER: This is basically the same process that you would use for new plant licensing.

MR. COZENS: New plants and existing plants that are not looking at license renewal. Any time you have a program commitment or commitment to generic letter or bulletin or anything that you say, "I'm going to do something," and you give one level of detail, the region has the responsibility to look at the implementation of it. The same here.

MR. SIEBER: So this isn't different than what the practice has been in all kinds of areas?

MR. COZENS: That is correct.

DR. WALLIS: So, it's conceivable that although it looks as if this -- not necessarily this plant -- some plant has a license renewed, it's quite conceivable that they do such a lousy job of actually implementing these programs that the region comes back before they actually start up the new period of license and says this isn't good enough?

MR. COZENS: What happens is -- what is taken away from a renewed license, the new part of it is the commitment to implement programs necessary to manage the aging. Should the applicant make those commitments under the FSAR and the region go out and find out that they're not adequately implementing those programs, they are subject to enforcement action. So, it is a checks and balances --

DR. WALLIS: But they still have the license?

MR. COZENS: They still have a license, but they could be found in non-compliance.

DR. WALLIS: So, there's no, there's no threat that you won't get your license renewed because you haven't done what you promised to do?

CHAIRMAN BONACA: There is the actual matrix.

MS. RODRIGUEZ: Right.

DR. WALLIS: But they still get the license. It's when they get the license renewed that they go through that.

MS. RODRIGUEZ: Yes.

MR. SIEBER: They get the renewed license before the commitment to have the program.

MS. RODRIGUEZ: The ROP takes over.

MR. COZENS: That's correct. The commitments aren't required to be implemented until after the applicant license is granted.

MR. ROSEN: Is there an SDP in the ROP for a significance determination process in reactor oversight program for license renewal?

MR. SIEBER: No.

MR. ROSEN: So what would you cite against? What color would it be and how would you figure it out?

MS. RODRIGUEZ: I'm going to refer that to Patricia.

MR. LOUGHEED: Hi, this is Patricia Lougheed. I'm one of those inspectors in the regions that's going to be responsible for implementing this in the long-term. Basically, no, there is not an SDP for license renewal. When it is the period of extended operation, they will be expected to conform

to the same requirements as they are prior to the period of extended operation. If they don't meet their commitments, that would probably be coming under what we would call "traditional enforcement" and we would go to the Enforcement Policy to determine the significance of those actions. It would not be assigned a color, as one said, but would be assigned a severity level. It would depend upon exactly what was not met and to what extent it was not met, but it would not just be ignored or forgotten.

DR. WALLIS: This is what puzzles me a bit. It's the same requirement as before the period of extended operation and yet, in order to get this license renewal, they have to upgrade their AMRs, so it's not the same requirement if they're not going to have some upgraded programs. So, why is it the same requirement as before? It doesn't seem to be quite consistent.

MR. LOUGHEED: What it is is they're required to have -- they're required to make their, to keep their commitments and in terms of what we will look at, it is going to be functionality of the equipment, and continued operation of the equipment, which is what the significance determination process looks at. In terms of not keeping a commitment, we

will look at that to determine how significant they're not keeping the commitment was. If it's just a case of, for example, one procedure didn't get updated, that might be minor. If it's a case where an entire program did not get implemented, that would be more major. You know, it's kind of hard to make a judgment now when we don't know what it will be. But we will be looking at -- right now, they have commitments that were put in place like after TMI, after various other events, because of generic letters. In those cases, they will give us commitment and they'll say, oh, by year "X", we are going to have this program in place. So we go out and we look, after year "X", and verify that the programs are in place. This is not going to be any different than those types of commitments, while we will continue to do our inspections and continue to look at what they are doing to make sure that they are operating safely.

MS. RODRIGUEZ: Okay.

MR. SIEBER: I have another question, and you can correct me if I have a misimpression, but in looking through a bunch of LRA applications and SERs, I recall numbers of Aging Management Programs higher, you know, in the 30's as opposed to her to the tune of 20, is that, first of all true for this kind of a

plant, and if so, what's the difference?

MR. COZENS: Let me address that question. The packing of an Aging Management Program is up to the applicant and how they propose to meet it and it probably relates back to the actual existing programs they have in their plants. As a general rule of thumb, we do not request that the applicant redefine its programs if its program is, indeed, adequate. So, as you say, some renews have had probably up into the 40's. I can think of one recently that may have had that high. But as long as they can demonstrate that the criteria that they say are consistent with GALL, let's say, are met within one of their programs, however they group these programs, then that would be defined as meeting the consistency criteria and would be considered acceptable. So, it's just a matter of choice on how broad these programs can be. It's again, all the attributes necessary to manage aging affects would be captured in one of these.

MR. SIEBER: So a licensee AMP may have several GALL attributes?

MR. COZENS: Oh, absolutely, yes.

MR. SIEBER: Okay.

MR. COZENS: This is not new or unique to this application. It's always been that way.

MR. SIEBER: Okay. Thank you.

MR. COZENS: It varies.

MR. SIEBER: Well, the umbers struck me.

MR. COZENS: Yes.

MS. RODRIGUEZ: Let's go to --

MR. SIEBER: I thought maybe since it was a two-loop plant, they only had to --

MR. COZENS: No.

(LAUGHTER.)

MR. SIEBER: -- two-thirds of the aging management to do.

MR. COZENS: It's just a matter of choice.

As I said, we are going to talk about this -- as a matter of fact, I believe Jim Knorr also touched on this. As they said, the format of the application that the applicant used was, I believe, Rev. 3 of NEI 95-10 in the Reg. Guide 1.188. But they did one additional thing that had a lot of benefits, but it caused come challenges also. Basically what the applicant did in its application is they took their basis documents and added into the application the bulk of what was in their basis documents and said why are these programs adequate. From a reviewer/auditor point of view, this is very beneficial to us because all of the information is

contained largely in the application. We did not have to go to far a field. Another intended consequence that was also talked about here, is -- I believe Dr. Wallace had actually mentioned this -- is the fact that in the area of enhancements, they did two things. They had two meanings of the word "enhancements." One which we would typically review and one which fits more in the category of what the region would expect. The first definition that was pretty much used was the concept that an enhancement was an action that was necessary on an existing program that they were crediting that they needed to implement prior to the period of extended operation to make that program consistent with GALL. That's the minority of activities that were performed under the terminology. The bulk, if not the vast majority, of areas where they called these things enhancements were those actions they needed to do to take an acceptable program and actually implement it in the plant. And they made quite a few enhancement commitments on that characterization. Those areas that while we actually did agree these were god and proper things to do, they should be done, the implementation procedures that, one, may not have been written yet, two, we don't necessarily know if it's all the activities that they

need to do to make certain the implementation of this program as defined to satisfy the regulations, is robust enough. Those things cannot really be reviewed until they actually do implement these programs to see how they're being done. Again, that falls back on the responsibility of the region to oversee these commitments, to have these programs in the implementation phase of it.

Therefore, when it was the things that region will be looking at in the future, we, the Project Team, did not review those. We classified them as "Administrative," meaning directly that they are to be looked at in the future by the region as they saw fit. So you will see some write-ups in the slides that are shown and also in the draft SER that talk about enhancements that are administrative and we not reviewed by the audit staff. The reason is it was premature. It wasn't in our scope of activities. So those are on the table. They are part of the applications and they are things that we'll need to do to make certain that their programs are appropriately implemented, but it is not in the scope of the audit and review.

DR. WALLIS: Does this mean that the bar gets raised when you get a new license, that before

you have a new license, you can get by with the programs you have now; after you have it, you have to have an enhanced program which is requiring something which was not required before?

MR. COZENS: The entire scope of license renewal is, indeed, at that, exactly what you speak to. The concept of license -- the Part 54 Rule is that we are trying to make certain that the aging effects that are existing have an Aging Management Program that's sufficient to manage that aging effect. That may means that there is augmented inspections that are necessary to be done, such as in the area of the ASME Code where we talked about augmented inspections that are necessary. There are things above and beyond the CLB that are not required by the current regulations, that because of the Part 54, the applicant has to take extra steps. So, yes.

Next slide. Here's a classic example. This is actually representing three that are asked -- pressure boundary, ASME Code, pressure boundary, containment and supports. The applicant had a large number of exceptions that they proposed to take with regards to these and they based the acceptability of these exceptions on the relief request. Quite frankly, the staff does not consider the existence of

an existing relief request that's been approved by staff, sufficient to make a determination whether or not an Aging Management Program is sufficient. A classic example: approximately 50 percent of the relief requests are granted on hardship. That doesn't mean that you're managing your aging. You need to look further. You need to come up with a technical justification as to why it is. The same thing, many of the relief requests probably don't need exceptions because they're not something explicitly necessary to managing -- for the aging program. And that's something that has to yet be sorted out.

DR. WALLIS: Do these exceptions keep going after license renewal?

MR. COZENS: The relief requests or the exceptions?

DR. WALLIS: The exceptions. Are they stopped after license renewal or do you have to do something --

MR. COZENS: No, the exceptions become applicable at the period of extended operation beginning. Therefore, the period of extended operation where you -- because the programs that you need in place t0 manage the aging affect are for the period of extended operation. You could define an

Aging Management Program that's not necessary to meet current regulations, but is necessary to meet Part 54 and the period of extended operation. So you are looking beyond that. So, quite frankly, when anybody has a relief request in the future that goes into the period of extended operation and it affects an Aging Management Program, that should be examined for that also.

CHAIRMAN BONACA: I thought that there was an unusually high number of relief requests on this side.

MR. COZENS: Yes, so did we. This is the first application we had seen that they had cited so many. I think there was 18 or 19 of them.

CHAIRMAN BONACA: Yes.

MR. COZENS: That is currently an open item. We have had a significant number of discussions with the applicant, trying to work through this, but the bottom line is did we check with OGC. Yes, they can take an exception to these GALL AMPS, but those exceptions must be based upon technical arguments, supporting why the Aging Management Program will, indeed, be robust enough to managing the aging affect.

CHAIRMAN BONACA: Okay.

MR. COZENS: And that's still an open

item. I might note that the ISI, risk informed ISI Program, is one of these relief requests. That's still an open item. It is not a closed item at this point in time.

So, although I've seen some information on that, that is something that we need to get closure on, including the affect that you are, indeed, managing the aging effect and that you are looking at the most likely cases where you would be seeing some aging occurring and it wouldn't balance selection between one or more components that you may choose to do a one-time inspection. It makes more sense to choose the one that has more risk informed, if you're looking at apples and apples.

DR. WALLIS: So these relief requests must be based on technical arguments, which will not be resolved until these new national programs are in place?

MR. COZENS: No. No, that's not correct. The sheer existence of a relief request, we do not consider as a sufficient technical argument. So they need to come in today when we review their AMPs and build their case today --

DR. WALLIS: Build their technical case today.

MR. COZENS: These AMPs have not yet been accepted.

CHAIRMAN BONACA: Give us an example.

MR. COZENS: They have one relief request where they were granted relief based on basically hardship for inspecting three heat exchangers. They chose -- their basis was hardship plus the technical argument that they could chose the lowest heat exchanger because it had the hottest temperature associated with it. That doesn't quite answer my question on all the aging effects. We've lost the trail on stress corrosion cracking. There may be an argument there, but yet we haven't received that. We haven't walked through the discussions enough to know whether or not we will find that sufficient.

MR. ROSEN: Well, that's because the dominant failure mechanism may be flow related rather than temperature related.

MR. COZENS: Those are something to consider. You have to look at the aging effects we're trying to manage on those specific ones. They also need to be submitted with a specific citation of which GALL element -- what are they not inspecting versus what are they doing. We need them to have very explicit criteria of where are you taking it? What

are you taking exception to? Not the more global thing where you have a relief request which is in the category of, I was granted a relief request and I find that acceptable. I want to continue that. That just doesn't quite give us the argument that we need to examine it. So, again, these remain open.

Also, on these particular apps, there were CASS thermal aging statements that were made, I believe, with the Class 1, 2, 3 AMP, where they had proposed as the basis for the aging management, a leak-before-break argument. Staff felt that that was possibly not the right argument because it violates one of the tenants of the Aging Management Program that you are assured that the function component was maintained during the period of extended operation. And if you're committing leaking, that does not support that logic. Therefore, we wrote an RAI to the applicant and asked them to clarify how that would do that. In the process, the applicant has decided that they will be performing a flaw tolerance methodology or an enhanced volumetric inspection and that would, indeed, make them consistent with the GALL AMP. This is now a confirmatory item. We're waiting for this formal response to come back to us.

Next slide, please. In the Buried Service

Monitoring Program, this is an existing program of buried piping. It manages the external surfaces of carbon steel, low-alloy steel, cast iron buried components, the emergency power, service water and fire protection systems. In performing our review, an RAI was issued which asks some questions concerning the fire pipe that was buried. It asked the question of whether or not it was possible that some of the piping was not, indeed, coated. The applicant came back and stated that the piping was installed pursuant to an industry standard which may have allowed insulation without coating if the soil was not aggressive.

They had done at least one inspection on buried piping where they did find that particular piping was coated, but that it only had a very light -- not a very light -- a light coating --

DR. WALLIS: Was it still coated after being excavated?

MR. COZENS: Yes, sir. It had a light coating of material on it.

DR. WALLIS: Don't they also have to repair the -- I mean when you excavate the pipe, don't you scratch off some of the coating?

MR. COZENS: That is, indeed, one of the

concerns of having to mandate an excavation. But where they did do this particular one, they found that the coating was there and there was no --

DR. WALLIS: It's hard to know exactly when you're going to hit that pipe when you're excavating.

MR. COZENS: That's a challenge, that's true. One would have to evaluate what caused that break if that happened in the mandate.

But anyway, after 14 years of service, the applicant demonstrated that the coating was there. There was no external degradation and reconfirming that the soil was not an aggressive soil as defined in the GALL AMP. I think later in this presentation, we have some actual numbers of what the soil compensation chemistry is.

The applicant has committed to do a one-time inspection of the buried fire protection pipe prior to the period of extended operation. A susceptible section of the fire protection piping will be chosen for this inspection prior to the period of extended operation. However, if they should have an opportunity to do an opportunistic inspection, they will credit that because they are already there. As you say, if we're there.

The applicant also committed to performing an inspection of the buried piping systems at least once every ten years during the period of extended operation and also if there were an opportunity for an opportunistic inspection, they would credit that. The staff found that this response was acceptable.

The Cable Condition Monitoring Program actually encompasses three GALL AMPS, one of the opportunities we talked about. It managing aging and conductor insulated materials on cables and other electrical insulation materials that are, we're told, in adverse local environments caused by heat, radiation and moisture.

There are three AMPS, the first one which is where E1 out of the GALL report is the electrical cables and connectors -70 to a 54.49 (phonetic 3:52:37) qualification program. This AMP, the applicant did not identify any exceptions, nor did the staff find any to the GALL AMP. We found that AMP, indeed, was consistent with the GALL AMP.

In the E2 and E3 GALL AMPS, the applicant identified two exceptions to each of these AMPS. This program only addresses non-EQ instrument circuits, whereas the GALL AMP was addressed for all non-EQ instrument circuits. The staff found that this

exception was reasonable and acceptable. The Point Beach electrical cables associated with radiation monitoring are either environmentally qualified or installed in areas that are not subject to adverse local conditions, high temperature, high radiation situations. And so the audit team found that that exception was acceptable.

In the E2 AMP, the applicant also took exception to the suggestion of the testing of the nuclear instrumentation cable being defined in the tech spec that the -- the surveillance and the tech spec. Currently, the Point Beach AMP does not have this in its tech specs, but there's a commitment to have the cable periodically tested in accordance with the procedures. We found that as long as this testing was, indeed, being performed that we felt that that was reasonable and appropriate. So the staff found these exceptions also acceptable.

In E3, which is the medium voltage cable, medium voltage, inaccessible cable, the applicant, in its initial application took exception to the definition of "significant moisture." The GALL AMP defines "significant moisture" as exposure to moisture more than a few days. In the application, the applicant had proposed an alternate definition which

would have been exposure of more than a few years. The staff was a little uncomfortable with this particular definition that was proposed by the applicant and issued an RAI requesting clarification on how that definition could be technically supported. As a result, in their response, the applicant, because they are already testing, choosing to test every ten years, as one of the criteria that would have been defined in the GALL, chose to accept the definition for "significant moisture" as defined in GALL, they are not considered consistent with GALL. So staff found that acceptable, as well as their commitment where we asked for clarification. When we read the application on this particular AMP, the wording on whether they were inspecting or not, we weren't quite certain what was being said, and so the applicant, although they had, I believe, always intended to perform their inspections on a ten year frequency, clarified that it was their intent and the staff found that acceptable.

In the Flow-Accelerated Corrosion Program, this is an existing program. There was a confirmatory item associated with it. When, in the application, the applicant identified how they were performing this particular program and what their thresholds were for

minimal wall and things of this nature, the write-up wasn't real clear and crisp to us and so we -- with support of also -- I want you to know that Region III also helped us out in this area, we asked for clarification of their program. After receiving that, we concurred that the program was appropriate and have agreed that their definitions of how they're achieving definitions of minimum wall calculations for the ASME Code and when they will perform and expanded inspection, should they go below a certain minimum wall, we found those definitions acceptable.

MR. LEITCH: The criteria is still different for safety related and non-safety related?

MR. COZENS: Yes, that is correct.

MR. LEITCH: I'm a little surprised at that since, in addition to the nuclear safety implications of this, it is also a personnel safety implication. I'm just a little surprised that there's less restrictive criteria when the personnel hazard could be as great. It's perhaps not a regulatory issue directly, but it certainly is a safety issue. Personnel safety, not a nuclear safety. I was just surprised that that differentiation was made. But that may be more of a comment to the licensee than to the NRC.

DR. CHANG: This is Ken Chang. Maybe I can explain. The Class 1 and Class 2 has the required wall thickness or code required minimum wall thickness. They are the same. But at which condition the sample, the measuring sample in each will be expanded, the Class 1 and Class 2 and Class 3, is very different. But as far as the calculation, the definition of minimum wall, it's all the same.

MR. LEITCH: But the rejection criteria --

DR. CHANG: It's not a rejection criteria. It is that -- if you find the minimum wall -- the measurement of the wall is only 60 percent of the minimum wall thickness, then you expand the sample for the Class 2 and Class 3.

MR. LEITCH: Non-safety related?

DR. CHANG: Non-safety related, non-safety related, I'm sorry. But the Class 1, the safety related piping does not have that luxury. Your comment is right. Relating to whether the pipe is going to have the strength to take the pressure, take the loading, safety or non-safety, is the same. They shouldn't be two different numbers.

MR. LEITCH: Yes. This is a real issue. We've heard some people in power plants with these kinds of failures and I'm just, as I said, we hurt

them just as bad whether it's safety related piping or non-safety relating piping that fails. Just an editorial comment, I guess.

DR. WALLIS: The safety of the public and the safety of the workers are different things.

MR. COZENS: I'd like to now talk about the One-Time Inspection Program. This is a new program which the applicant has identified as being a decisional GALL report. During the process of performing our review, we noted that the identification of aging management methods based on aging effects was not cleanly linked. We couldn't quite tell when you have this aging effect, which one-time inspection might you perform. So during our site visits, we had discussions with the applicant and they voluntarily chose to identify for a given type of aging effect what form of aging management would be likely to be performed on this particular location. That resulted in a new table being added to the application in a docketed response, and also, I will note that this particular format of linking the aging effect with the Aging Management Program is now proposed to be added to the updated GALL report. We think that's a good enhancement that we'll carry forth.

MR. LEITCH: A question about this. In the inspection report on both Pages 12 and 19, it makes a comment about the One-Time Inspection Program, and for that matter, the Boraflex Monitoring Program.

MR. COZENS: Maybe we should let the region address that. Patricia?

MS. LOUGHEED: Do you want to finish your question?

MR. LEITCH: Sure. Basically --

(LAUGHTER.)

MR. ROSEN: Perhaps you could answer any question you like.

MR. LEITCH: It basically says that with certain changes, these programs will be acceptable. I'm not sure how that is documented. I guess my primary confusion is that this inspection report is dated the same date as the SER. Does the SER incorporate these exchanges, or if not, how is that commitment tracked?

MS. LOUGHEED: For the record, my name's Patricia Lougheed again. I'm the Region III Inspector. No -- in some cases, the SER did incorporate some of the items in our inspection report. In other cases, it didn't. It kind of depended on where a particular reviewer in NRR was at

the time that the Inspection Report was drafted and the amount of interface between our inspectors in NOR. Basically though in terms of coordination, I am keeping in very close contact with the NOR staff and the items that are listed as open items in my Inspection Report are going to be open items that will need to be followed up on even if they are not in the SER, as part of the third inspection, if at no other time, that we will be doing prior to the start of license renewal.

MR. LEITCH: So at the end --

MS. LOUGHEED: At the end, I --

MR. LEITCH: -- when we have a final SER, these will all come together?

MS. LOUGHEED: That's my responsibility, to make sure that they will all come together, yes.

MR. LEITCH: Thank you.

MR. SUBER: This is Gregory Suber. Just to piggyback on what Ms. Lougheed said, in fact, for the Boraflex Monitoring Program that you were talking about, we've already received a letter that fulfilled the commitments that were talked about in the Inspection Report and those items are actually closed now and you'll see it in the next phase of the presentation.

MR. LEITCH: Thank you.

MR. COZENS: Also during our review, on site, we had some discussions about and concerning the ability of detecting fouling that affects heat transfer and we did conclude that the use of ASME Section V, Visual Inspections, was one suitable means of detecting fouling that could indicate that there is, indeed, fouling or, therefore, the lack of anything that we would have visually inspected would be confirmation that it would be not a degraded condition as far as heat transfer goes.

In the process of defining what was an acceptable method for managing the various aging factors, the initial thought on selective leaching of cast materials was that the applicant believed that a visual inspection may be sufficient to characterize whether or not leaching was occurring. The staff, and in the GALL report, it states that we do not believe that it is an acceptable way of detecting leaching and an RAI was issued to the applicant requesting the to clarify how they would detect selective leaching using the visual inspection methodology. In their response to that RAI, the applicant has committed to performing hardness testing.

MR. ROSEN: I'm not sure I understand.

This is in what kind of piping?

MR. COZENS: Cast, cast iron.

MR. ROSEN: Cast iron piping. And they're going to do a hardness test on the outside of the piping?

MR. COZENS: This is -- valve bodies, I believe and it will be on the wetted surface --

MR. ROSEN: On the wetted surface.

MR. COZENS: -- that are accessible, that you can get to. There are multiple ways of performing hardness tests. Some of them are very micro-hardness testers that you can detect changes.

MR. ROSEN: On cast iron piping, so when they open up a system?

MR. COZENS: Yes. Yes, you can't do it while it's operational, of course.

MR. ROSEN: You mean, you'd be testing the outside and it wouldn't tell you anything.

MR. COZENS: Unless it's very severe.

MR. ROSEN: Right.

(LAUGHTER.)

MR. ROSEN: Now, do you understand metallurgically what's happening?

MR. COZENS: yes.

MR. ROSEN: That when you test hardness on

the inside of a system that's being leached, this carbon steel, that you have correlations between hardness and, say, yield strength of the material? I assume these -- some of these piping are safety related and have to withstand seismic and other loadings?

MR. COZENS: Yes. As far as that, you would be looking for a degradation of the hardness of the material because you would be basically hardness testing on a honeycomb surface.

MR. ROSEN: I'm trying to understand what a hardness test would tell you about the piping's capabilities.

MR. COZENS: It's not a measurement of leaching; it's a measurement of the correlation to degradation of loss of basically material which would have been leached away. So if you hardness-test on a surface that has leaching on it, you're basically punching through air. So you would see a significant degradation in the hardness.

MR. ROSEN: Is this a standard test?

MR. COZENS: This is what GALL is actually set up to do.

MR. ROSEN: I mean this is out of the ASTM?

MR. COZENS: No, I don't believe this is in the ASTM. I don't believe ASTM has addressed leaching. To my recollection, it hasn't.

So this was a test that was selected because it was capable of determining the degradation of the material quality.

MR. ROSEN: Well, wouldn't it be more accurate to take a section of the pipe out and to actually break it or in some way do a strength test on it. I mean just trying to relate hardness to the structural properties --

MR. COZENS: The situation would be that if one concluded that there was leaching occurring, then the corrective action program would kick in on to the next steps. That is, is the mechanism present or not because we are under one-time inspection mode where we have either an aging effect that, quite frankly, we're not certain is indeed occurring, so we're trying to confirm is there any indication that it might be occurring --

MR. ROSEN: Well, yes, but simply taking out a piece of the pipe and sectioning it and preparing it for metallurgical examination would tell you a whole lot more than a hardness test.

MR. COZENS: That's a true statement.

That requires a destructive testing, which when you don't know that it's existing, it's kind of difficult to --

MR. ROSEN: But this is a one-time inspection we're talking about, right?

MR. COZENS: It's a one-time inspection.

MR. ROSEN: I have questions about this, the technical adequacy of such a test. I mean, you might do it and conclude that the piping is, in fact, structurally sound, when, in fact, it's not. Unless you had some sort of database that relates hardness to strength.

MR. COZENS: The test is not intended to make a determination of whether the component was capable of performing that service. The test is intended to identify whether or not the aging mechanism exists. Just a screening test. Should you find leaching, then you have a whole bunch of other engineering decisions to make.

DR. SHACK: Yes. If you've just leached a surface layer, you can detect that, presumably. It indicates that the mechanism is occurring. After that, you know, you've got a bigger set of decisions to make.

MR. ROSEN: Is this one piece of pipe at

one place?

MR. COZENS: No, it's several different -- I think it would be more than one location. I don't think it's only one. I don't know offhand exactly.

MR. ROSEN: Well, what systems have cast iron in them that we're talking about here?

MR. SIEBER: Fire.

MR. COZENS: Fire protection, yes. Maybe the applicant could -- my memory isn't that good on the 1200 line items.

MS. RODRIGUEZ: What components --

MR. COZENS: Which systems have the potential material in them?

MR. KNORR: This is Jim Knorr again. It's fire protection piping that is cast in some cases. Not only the piping, but the valve bodies in some cases.

MR. COZENS: It's the valve bodies that would be tested when they're open.

CHAIRMAN BONACA: Yes. Go ahead.

MR. COZENS: The next slide is also on one-time inspection because the applicant had noted one exception. That in the one-time inspection AMP and GALL incorporates the inspection of small bore piping, they had not included the small bore piping in

their scope for the one-time inspection. So they took an exception. However, they did note that the one-time -- that the inspection of small bore piping would be performed per their risk informed ISI. As I have noticed before, the exception to that program is still an open item, but under that program, they would, indeed, be performing a biometric inspection which is critical for the inspection of small bore piping and that based upon some input that I have had, although we have not formally received or accepted, they do, I believe, incorporate into their consideration of risk informed inspections the aging mechanisms, their locations, and the materials that would be subject to this degradation.

The half, as I said, were Administrative, as a matter of fact, all of these slides that I have up in this particular case, are all (inaudible 4:11:50) and there were two open items, and these are actually probably akin to the AMR line items that I think are going to be mentioned later. That there were some heat exchangers which the AMRs had only credited what the water chemistry program, and there's an RAI that is out which we have not closed out as of yet that asks the question why is there not some sort of verification of this water chemistry program as we

might have expected under the GALL guidance and not just looking at it to confirm that the monitoring program of the water chemistry, did get a water chemistry program is sufficient, and so we are looking to close that out in the future. We've already had some discussions on that and may have a resolution, but we need to see that when it comes in.

That concludes my remarks.

MS. RODRIGUEZ: Okay. Continuing with the AMPs, the Bolting Integrity Program is an existing program consisting consistent with the GALL report. The applicant had identified exceptions to the GALL. Here is where we have one open item. The Bolting Integrity Program relies on recommendations from several guidance documents, including EPRI documents and NUREGs. The applicant wants to take exceptions to some of these documents, but they haven't stated specific exceptions and the staff requested the applicant to submit the exceptions and their details for NRC review and approval.

Next slide. This one --

DR. SHACK: They asked for an exception without telling you what the exception was?

MS. RODRIGUEZ: They haven't explained what documents they want to take exception to.

DR. WALLIS: And the enhancements have nothing to do with the exception?

MS. RODRIGUEZ: The enhancements are Admin.

DR. WALLIS: These Admin enhancements, what does that mean? It simply means that they do a better job of administrating the program or that should change a lot of things?

MS. RODRIGUEZ: They're usually --

MR. COZENS: As I explained earlier in my slides, the bulk of the enhancements that were identified were implementation attributes of the program and what we're performing is the program review here. The region will be --

DR. WALLIS: That means doing something more times than they did before, or something like that?

MR. COZENS: You have a program, one program, but you may have many implementing documents and so that's the next phase of taking the defined program, which has acceptable boundaries, and taking it to the next phase. That's done in the future and the region has responsibility to confirm it and monitor implementation and with other commitments.

MS. RODRIGUEZ: Patricia, do you want to

add something?

MS. LOUGHEED: This is Patricia Lougheed. To go back on the exception, this is one of the things that we did look at through the inspection and at the time that the application had gone in, the applicant had not looked through the EPRI documents to be able to define precisely which areas they were taking exception to. During the inspection, they actually did do that and came up with several specific areas where they basically refined the exception. I know that that has been submitted to NOR and is under review now.

MS. RODRIGUEZ: Thanks. Okay, this concludes the AMP subscriptions. We're going to continue with the AMRs. Section 3.1, Reactor Vessels, Internals, and Reactor Coolant Systems. We have one open item, which was previously discussed by Kurt with regard to steam generator loss of material evaluation where the applicant uses the Water Chemistry Control Program as the only AMP for managing loads of material. There is no program to validate the effectiveness of this water chemistry.

One more thing that is worth mentioning in this light is that the applicant has committed to submit the reactor vessels internal programs for NRC

review and approval two years prior to entering the period of extended operations, which is what you have seen in previous applications.

Section 3.3, (inaudible 4:16:10). We also have one open item similar to the previous one discussed regarding component cooling water cracking evaluation. Again, the applicant uses the Water Chemistry Control Program as the only AMP for managing loss of material.

Next slide. Section 3.5, Containment, Structures, and Component Supports. In Section 3.5, we have one open item related to the containment liner and loss of material evaluation. The staff has requested the applicant to submit procedural descriptions, repair guidelines, and acceptance criteria for identifying corrective actions when loss of material is observed.

In Sections 3.2, 3.4 and 3.6, the staff has not identified any open items or any confirmatory items.

DR. WALLIS: Do you really lose material from a containment liner?

MS. RODRIGUEZ: I'm sorry?

DR. WALLIS: Do you really lose a significant amount of material from a containment

liner?

MS. RODRIGUEZ: For this --

MR. SIEBER: If you work on it.

DR. WALLIS: If you work on it, you can.

MS. RODRIGUEZ: For this specific open item, we were talking about some areas that had some drilling and the staff is getting information on that.

DR. WALLIS: This is drilling?

MS. RODRIGUEZ: Yes.

MR. ROSEN: This was an attempt to take samples or something? There was somewhere they said 46 percent wall loss.

MS. RODRIGUEZ: That's correct. Those specific --

DR. WALLIS: Forty-six percent wall loss in a containment liner?

MS. RODRIGUEZ: Yes.

DR. WALLIS: That's a lot of material.

MS. RODRIGUEZ: Yes, that's why it's an open item.

MR. ROSEN: Not surface area, you put them at a depth.

DR. WALLIS: But even depth --

MS. RODRIGUEZ: Jim, do you want to say something?

MR. KNORR: This is Jim Knorr. A number of years back, and I'm trying to remember, I think it's in the late `80's, there was a question as to whether or not there was any water getting in underneath the concrete base pad, and of course, there's a liner underneath that. So, Point Beach took it upon themselves to drill into the concrete and apparently were not careful enough and we actually drilled into the liner and that's what you're seeing here. We identified this as an effect that we had to evaluate and so we used it and gave you all the information in the application or in response to an RAI. That's what happened here. If you've got any specific questions, I can try and answer those.

MR. SIEBER: Did you pass a leak rate test?

MR. KNORR: Yes, we have passed a number of integrated leak rate tests since then. Because it was, again, what .4 -- forty percent of wall thickness? I think it was the worst case.

MR. LEITCH: I was getting this mixed up with the erosion of the borated water. These are two different issues?

MR. KNORR: Totally two different issues.

MR. LEITCH: I see.

DR. WALLIS: Presumably, it's a very local thing. They didn't drill everywhere, did they?

MR. KNORR: That is correct, sir.

MR. ROSEN: They got the guy who was doing it, by the way.

CHAIRMAN BONACA: So, now we have a license to do inspections?

MS. RODRIGUEZ: Okay. This concludes my part of the presentation. I'm going to turn the presentation over to Gregory Suber and Ms. Patricia Lougheed.

MR. LOUGHEED: Hello. This is the official part of my presentation. My name is Patricia Lougheed. I am the Region III Lead Inspector for License Renewal. Basically, we did a 3-week inspection which was a combined scoping and screening in aging management. This is something new. Previously, they had been separate inspections. And we also, because of the timing of the Unit 2 outage, also had an opportunity to go back a couple weeks later and take a look inside the containment, areas that would not normally be accessible during power operation. I've got kind of a, in the next slide, actually, if you'll notice, there are actually six inspectors. The last person was only on the

inspection for the first week of the three. I'm going to make a plea that, for all the powers that be, as you've heard, there's a number of activities that are very important in license renewal that require a regional inspection, and we do continue to get our staffing cut, so anyone that has any power to keep it going, I'd appreciate it. I'd like to keep my team together.

MR. SIEBER: You're in the wrong place.

MR. LOUGHEED: I know.

MR. SIEBER: There's no power at all.

MR. LOUGHEED: I'm going to mention it. It is a concern of ours, too, because we do recognize the number of things that are on our plates in terms of actually doing the inspections, after the license is granted.

For scoping and screening, we looked at the electrical, structural and mechanical systems. We did a lot of time out in the plant, actually looking to see what was in conjunction, especially for the (a)(2), the non-safety interfacing with safety. We spent a lot of time looking at that. We found that, as far as we could tell, the majority of systems were appropriately scoped. We did not find any non-safety systems that should have been in scope and weren't.

At the time we did our inspection, the applicant had not completed its re-review of the (a)(2) systems, so as that is an open item under the SER, the region is standing ready that if the NOR needs additional onsite inspection, we will be glad to do it.

In terms of the Aging Management Program, we reviewed 16 of the 26 Aging Management Programs. We also looked at two time-limited aging analyses programs. I've got on the next slide the number that we did. Again, we interfaced strongly with NOR to try and make sure that we were looking in the areas where the NOR reviewers had questions and where we could provide additional information.

We concentrated on looking at what the plant was doing right now, what the programs actually were. We looked at what the history was and what their operating experience was. And we --

CHAIRMAN BONACA: A question I have is you've reviewed a number of the programs and, as you know, there is also a separate effort taking place led by Pacific Northwest National Lab --

MR. LOUGHEED: Right.

CHAIRMAN BONACA: -- that also did inspections. Do you coordinate at all with them because I see the dates are different.

MR. LOUGHEED: It has not happened so far and, quite honestly, our budget does not allow for us to really coordinate strongly with the audit teams. The difference --

CHAIRMAN BONACA: But that's more that the timing -- I mean, I guess doesn't allow you to do that, but wouldn't it be useful?

MR. LOUGHEED: Yes, I agree it would be very useful.

CHAIRMAN BONACA: Because it seems to me that you're performing an inspection and they're performing an inspection, and you're looking at similar things when you're looking at the programs, and you could certainly be more efficient if you did see or communicated the results.

MR. SUBER: Actually, what we do is we kind of rely on the Project Manager to fill that gap and to make sure that there is some communication between what the staff is doing, with PNNL being part of the staff, and what's occurring at the regional inspection. In fact, in this case, I was the PM and I went out and I participated in the regional inspections and I brought with me a whole wealth of knowledge of everything that occurred during the in-house staff review as well as during the audit. So,

that synergy is built up, but it's in a separate way. Patricia doesn't directly interface with PNNL, but our Project Managers do.

MR. LOUGHEED: Yes.

CHAIRMAN BONACA: Yes, but it's also the --the report from Battelle is April 11, 2005. So it's also really recent. So, the integration happens at the end as insights and I was just wondering --

MR. LOUGHEED: In this particular case, that's true. They did happen very close together. We're trying, as we go on, to get better overlap so that we aren't duplicating -- and I don't think we did a lot of duplication. I think that what the region looks at is more the implementation and more the operating history so that we know that, as you commented about the enhancements and whether -- how do we know that these commitments are going to be met. You know, those are the sorts of things that the regions are looking into, how exactly is the applicant, in their role as licensee, holding the current operating license, how are they actually performing now? What are their plans for the future? You know, what is the actual condition of their plant? So, we spend a lot more time out in the plant looking at things and looking at current operation, and I

think that's where our difference is.

CHAIRMAN BONACA: Right.

MR. LEITCH: Patricia, I notice --

DR. WALLIS: There is some overlap, and then you could have a check, don't you agree.

MR. LOUGHEED: Yes, it would be good.

DR. WALLIS: Don't you deliberately have some overlap as a check?

MR. LOUGHEED: We don't currently have -- currently, right now, we rely on the Project Manager and we were very glad to have Mr. Suber here because he provided excellent overlap.

DR. WALLIS: So he looks at the two and sees that they are compatible?

MR. LOUGHEED: That's correct.

DR. WALLIS: He makes sure they don't overlap so he doesn't have any conflicts, is that what he does?

(LAUGHTER.)

MR. LOUGHEED: He did an extraordinary job making sure that we looked at the right things.

DR. WALLIS: Did he look at overlaps?

MR. SUBER: When Patricia set out her agenda -- of course, there was some overlap. And we didn't, per se, try to avoid overlapping reviews.

There was some redundancy in -- and I don't see that as an inefficiency. I see it as -- like you're saying -- I see it as an --

DR. WALLIS: Did they agree when they both did the same job? Did they get the same results?

MR. SUBER: Actually, we got more commitments with respect to the Boraflex Monitoring Program when we reviewed the program under the regional inspection. We actually found some problems that weren't picked up during the PNNL review and we obtained several additional commitments. And they were also issues with the same program that were raised by members of the staff. So we did, we looked at the same things, and we garnered additional commitments for that particular program.

MR. LOUGHEED: Well, we kind of picked up where they left off. We looked at what their -- we didn't have their audit report, but we had their questions and the responses to those questions.

DR. WALLIS: So you enhanced their report?

MR. LOUGHEED: So we kind of -- yes, that's a good word for it. Kind of picked up from where they left off.

MR. LEITCH: Patricia, I noticed that there are three systems here: aux steam, chemical and

volume, and feedwater system, where the comment is made that the proposed boundaries are not yet complete.

MR. LOUGHEED: That was correct at the time of the report. The applicant was still re-reviewing the (a)(2) non-safety systems interacting with safety and they had not, at the time of our inspection, fully determined where those boundaries were going to be. They have, since the time of the inspection, sent in a response to NOR and which gave the final boundary locations and everything. That is being reviewed now.

So we were just trying to say that we felt that the approach that they were taking appeared to be correct, but because it wasn't finalized, we weren't going to bless it off ahead of time.

MR. LEITCH: It just seems fairly late in the process. This inspection was just done within the last month or two. It just seems to me to be quite late in the process for establishing the boundaries.

MR. LOUGHEED: I agree, and I think that is something that the applicant has really struggled with.

MR. SIEBER: But they just recently changed their approach, too.

MR. LOUGHEED: Yes.

MR. SIEBER: So that sort of accounts for the delay.

MR. ROSEN: Well, that was pretty late in the process, too.

MR. LOUGHEED: Yes.

MR. LEITCH: I noticed a similar comment. It says, "Some additional non-safety related components needed to be placed in scope." That's says that the inspection report is dated 5/2/05.

MR. LOUGHEED: Right.

MR. LEITCH: Has that been resolved?

MR. LOUGHEED: I believe Jim Knorr --

MR. KNORR: This is Jim Knorr again. We have since responded. We completed our methodology description and sent that in to the NRC and also sent them changes to the application which describe the additional items that are in scope, as well as adding an additional system, which I think was discussed earlier in one of the slides.

CHAIRMAN BONACA: All right.

MR. LEITCH: Again, it seems late, but --

MR. LOUGHEED: I am sure that everyone would agree with that.

Basically, going back to the Aging

Management Programs, one of the issues that we determined required additional work was in the one-time inspection program. Basically, the applicant had not yet developed the program sufficiently for us to determine the adequacy in terms of the number of samples and the locations of those samples. At the end of the inspection, they agreed that they would be submitting that to NRR once it was decided upon and that we would then perform further review if necessary.

MR. ROSEN: Is that before the SER?

MR. LOUGHEED: I believe that is before the SER.

MR. KNORR: This is Jim Knorr again.

MR. ROSEN: I hope so.

MR. KNORR: What we have done is verbally committed to Patricia and to Mr. Suber here that our plans are to complete our identification, our methodology, our sample selection, and give that to the NRC for their review prior to the end of the summer. It's turned out to be a rather lengthy process and we're in the process of doing that right now and it should be complete by the end of the summer, prior to that final SER.

MR. ROSEN: Okay.

MR. LOUGHEED: That basically concludes my portion. Greg?

MR. LEITCH: Patricia, just before you leave, I was wondering -- I'm still a little confused about this corrosion of the Number Two containment liner. You had an opportunity to look, to go inside that containment. I'm not talking about where they drilled inadvertently the hole, but I mean this corrosion from the borated water. Is that still evident or has that been repaired?

MR. LOUGHEED: That has been repaired and we did have an inspector go in and look as close as he could at the containment liner. His review, basically, if I remember correctly, was that he did not see any overall corrosion; that it was a very limited problem that has been fixed.

MR. LEITCH: Okay, thanks.

MR. SUBER: Good afternoon, everyone. Once again, my name is Gregory Suber and I'm going to do an overview for Chapter 4.

The applicant submitted seven sets of TLAAs in this application. Point Beach identified three TLAAs for reactor vessel internals, neutron and (inaudible 4:33:58). They were pressurized thermal shock, upper shelf energy and P-T limits.

The applicant's use of the 53 EFPY is based on an assumed 95 percent capacity factor from the latest cast results and projected through the period of extended operations.

The applicant provided the PTS values you see here. The staff performed independent calculations and those values are also displayed on the slide. Note that the PTS value for the limiting material for Unit 2 is projected to exceed the screening criteria in 2017. It should be noted that these values are based on a conservative fluence projection. For example, the calculated values do not credit the use of hafnium absorbers. And I would just like to take a second to make one comment about the master curve. The applicant did submit a master curve, but the staff was unable to review it and facilitate the schedule, so the applicant took an alternative means to satisfy the rule.

CHAIRMAN BONACA: I appreciate your clarification. It wasn't clear to me.

MR. ROSEN: But he did take credit for the hafnium?

MR. SUBER: They did take credit for the hafnium, yes. No, no, in the calculation, no.

DR. WALLIS: Why are these values so

different from the two units?

MR. SUBER: Mr. Neil Ray?

MR. RAY: Hi, this is Neal Ray with Materials Chemical Engineering Branch. The fundamental difference between -- these two vessels are, as you know, pretty much identical in terms of design and engineering.

DR. WALLIS: The chemistry is the same?

MR. RAY: No, the chemistry is not the same.

DR. WALLIS: Okay. That's the answer then.

MR. RAY: Well, in order to answer you in more detail, the chemistry is also fairly close. However, Unit One vessel is the measured fracture toughness or measured RTNDT, the initial RTNDT, whereas Unit Two does not. So, the margins are significantly higher for Unit two and that's why one is 299 and the other one is 3 --

DR. WALLIS: It's being more conservative?

MR. RAY: Yes, it is.

DR. WALLIS: It's not physically different; it's just a way of calculating?

MR. RAY: No, that is not true because Unit Two, where is the Lindy 80 weld, the kind of

generic B&W weld, and so we have to use the center division for the initial opportunity is much higher, whereas Unit One, the initial opportunity are measured and that's why you --

DR. WALLIS: The difference is the way in which you calculate it?

MR. RAY: You can say that, yes.

DR. WALLIS: One's realistic and one is conservative?

MR. RAY: No, that's the way it is.

(LAUGHTER.)

DR. WALLIS: That's a wise answer.

MR. SUBER: So consistent with the Triple I Management option in the rule, and the EDO memo to the Commission dated May 27, 2004, the applicant has committed to, and the staff has accepted a plan to meet the PTS requirements of the rule, which include continued use of a low-leakage loading fuel pattern, continued use of hafnium in Unit Two --

DR. WALLIS: All of this doesn't make it, does it?

MR. SUBER: Pardon me?

DR. WALLIS: All of this stuff doesn't make it?

MR. SUBER: No.

DR. WALLIS: You still have to do something else?

MR. SUBER: That's probably true.

MR. KNORR: That is correct. This is Jim Knorr again. Even with all of this, Unit Two does not make it.

DR. WALLIS: So what do you do, shut down for a few years or what?

MR. KNORR: The rule requires, 50.61 requires us three years prior to reaching our acceptance criteria, to either come up with a way to reduce the flux or to again, as I mentioned earlier, to license an additional or different analysis technique such as (inaudible (4:38:03), or the third option, which is our preferable one, is to wait for the rule change, which we expect in the next few years which will take the acceptance criteria up above 320 to 25 degrees.

DR. WALLIS: Would thermal annealing get you through if you did that?

MR. KNORR: We did list that as one option in our application. I do not expect that we would use that option, but I think the answer is yes, if we chose to anneal, that could do it.

MR. SIEBER: Put charcoal in there.

DR. SHACK: But the 2017 again doesn't improve the effect of the hafnium absorbers, so if they continue to run wit the hafnium, they could --

MR. SUBER: They'll get past that.

MR. KNORR: It would be slightly past that, only slightly.

DR. WALLIS: Analysis will come.

MR. LEITCH: I have a question about -- maybe it's back to Slide 30. The limiting weld, that intermediate to lower shell circumferential weld. I'm looking at a report, BAW-2467 NP, and Page 11 of 44, shows a weld that I guess is intermediate to lower shell and it's called Weld SA 1484. Is that just a different numbering system?

MR. MITCHELL: This is Matthew Mitchell. Section Chief, Materials and Chemical Engineering Branch, NRR. There are a number of designators that go with these welds. The designator you see on the screen is actually the weld wire heat number that was used to manufacture the weld. The designator, I think, you're reading is a weld specific type designator, so it's a nomenclature difference. It has a different meaning from the weld wire heat number.

MR. LEITCH: Okay, but we're talking about the same weld. Now, immediately above that weld, in

this report, there's a weld that's called -- it's just referred to as "CE Weld." And it's not discussed in this report. Were some of these welds made by CE and other welds made by other than CE, like B&W?

MR. SUBER: I'd have to defer to the applicant.

MR. KNORR: This is Jim Knorr again. The answer is yes, the Unit Two vessel was initially started by Babcock & Wilcox and they did not complete it and then we went on to have Combustion Engineering actually complete the vessel and its welds.

MR. LEITCH: I see. Now, this report seems to be silent on that CE weld. Do we know that that weld is not limiting? I mean this report doesn't discuss the CE weld.

MR. RAY: This is Neil Ray again. To answer your question, the answer is yes. This one, 72442 is a limiting weld and it is the same weld as you said SA1484. It is just two different ways of nomenclature.

CHAIRMAN BONACA: So it is a CE weld?

MR. RAY: No, this is a B&W.

MR. LEITCH: But let me just be sure I -- you have looked at the CE weld and it is not limiting?

MR. RAY: That is correct, yes.

MR. SUBER: Okay. So that brings us to upper shelf energy. Both units at Point Beach are below the acceptance criteria for upper shelf energy. The estimated value is approximately 35-foot pounds. The applicant has performed an equivalent margin analysis that satisfies the Performance Review Authority 50 requirement. The staff has previously accepted this methodology for the reviews of Surry and Ginna.

In addition, the staff has also performed independent analysis that confirm that the applicant's conclusions are valid and that the analysis is projected through the period of its operation.

DR. WALLIS: The actual upper shelf energy is 35-foot-pound?

MR. SUBER: The approximate, yes. It's approximate.

DR. WALLIS: So even though it seems to be such a long way from the acceptance criteria, by doing some other analysis, you can make sure it's okay?

MR. SUBER: Yes, sir, doing the equivalent margin analysis. The staff verified that it was okay. Actually, they verified that the --

DR. WALLIS: How bad can they get and still meet the equivalent margin analysis?

MR. SUBER: Okay, that's an interesting question.

MR. MITCHELL: This is Matthew Mitchell again. The staff has not attempted to evaluate how bad a particular weld could be.

DR. WALLIS: When you do the analysis, you can tell how close you are.

MR. MITCHELL: You can get an idea, but it is also, in part, dependent upon the transients, the geometry of the vessel, the wall thickness, the rates. There are a number of other factors which may be vessel-specific, which could have influences on the EPFM analysis that supports the EMA.

DR. WALLIS: So when you do analyses, do you say if it's bigger than 30, it's okay? You must have some number you find?

MR. MATTHEWS: No, the equivalent margins analysis is actually a J-integral-based approach that --

DR. WALLIS: A different approach altogether?

MR. MATTHEWS: Yes. It's a much more detailed --

DR. WALLIS: Based on this antique test of busting things?

MR. MATTHEWS: Yes, not directly. It's based upon knowing more about the actual fracture toughness properties and doing a more refined analysis to support alteration to the lower upper shelf energy values.

DR. WALLIS: So it's really a better, more thorough analysis?

MR. MATTHEWS: Yes.

MR. SUBER: The staff evaluated the applicant's TLAAs associated with metal fatigue and found that the analysis have been projected to the end of the period of extended operation.

Similarly, the TLAAs associated with fracture mechanics were also projected to the period of extended operation.

DR. SHACK: Can we just go back to the environmental assisted fatigue? How do they do that since they don't have a real fatigue analysis for the 31.1 piping?

Mr. Mark Hartzman did that review.

MR. HARTZMAN: Can you repeat your question, please? This is Mark Hartzman from Mechanical Engineering.

DR. SHACK: They don't really have an analysis that gives them usage factors and such for

their piping.

MR. HARTZMAN: That is correct. What they do is they determine the number of cycles for which they can -- which would be below 7,000.

DR. SHACK: But then how do you do the environmentally assisted fatigue analysis?

MR. HARTZMAN: It doesn't enter into the picture, basically in some cases. In other cases, they actually have done a fatigue, a Class 1 fatigue analysis.

DR. SHACK: So they do enough Class 1 fatigue analyses to match up with the INEL for those particular joints, is that the idea?

MR. HARTZMAN: That is correct.

MR. SUBER: Okay. Thank you.

The predicted final effective pre-load exceeds the minimum required pre-load at 60 years, so the analysis remains valid through the period of extended operation.

DR. WALLIS: Could we go back to the other one about the fracture mechanics, about this pump flywheel which is going to operate for longer? Does it -- is it more likely to fracture as it gets older?

MR. SUBER: Yes, the pump flywheel?

DR. WALLIS: So what's the mechanism that

you're checking here when you do this analysis?

MR. SUBER: Okay, I believe Mr. Steingass did that review.

MS. RODRIGUEZ: That was Neil Ray.

MR. SUBER: Oh, it was Neil Ray. Sorry.

MR. RAY: Yes. What is the question again, please?

DR. WALLIS: I'm assuming as it gets older, it's more likely to fracture, is that true?

MR. RAY: Actually --

DR. WALLIS: If not, you don't need to do any analysis.

MR. RAY: Right. That's pretty much true. The reason being is for 32 EFPY, there was a history behind it and when that was first observed, to have heard that kind of inspection, Westinghouse did a generic analysis for 32 EFPY, meaning for the current license and then when they got the license renewal stuff coming, so they again re-analyzed it for 60 years with limited cycles. How many cycles are start and stop. In that --

DR. WALLIS: So this is a fatigue-type failure?

MR. RAY: That is correct, yes. And they did, in this assumption, there are 6,000 cycles and we

verified with the applicant the estimated cycles they are anticipating. And they responded by saying a maximum of 600, which is well below the Westinghouse estimate of 6,000.

DR. WALLIS: Thank you.

MR. SUBER: The projected and minimum values in kips for tendon are displayed for 40 and 60 years. This slide uses Unit Two data because Unit One values were even greater than Unit Two.

DR. WALLIS: So the acceptance criteria you're checking these against?

MR. SUBER: Pardon me? The projected, yes.

DR. WALLIS: What do I learn from these numbers, that they are bigger or less than something?

MR. SUBER: Yes, you learn the projected --

DR. WALLIS: The minimum is the required.

MR. SIEBER: Stronger than the minimum.

DR. WALLIS: So they're going to be bigger than 594?

MR. SUBER: Correct. The applicant will manage the aging effect of Boraflex using a Boraflex Monitoring Program. Based on the staff's review, and the regional inspection, the applicant committed to

revise its program and the commitments were received in a letter dated April 1, 2005. Therefore, these confirmatory items were closed out. I just wanted to make a note that in general the information that you see in the SER reflects the information that the staff -- that the applicant submitted up to and including March 31st. Of course, they've had subsequent correspondence come in, and so some of these items that you see as confirmatory items are now closed out. And the Boraflex Monitoring Program was one example of that.

The applicant's EQ Program is consistent with GALL and is adequate for the period of its operation.

This concludes the staff presentation and I would like to thank you for your time and for your attention.

MR. LEITCH: Going back to this TLAA on PTS.

MR. SUBER: Yes, sir?

MR. LEITCH: I guess I'm coming away with the conclusion that every one that we've looked at thus far, when we've agreed to extend the license for 20 years, we not only give them permission to run for another 20 years, but it looks as though they can run

for another 20 years.

MR. SUBER: Correct. This is the first plant that didn't have --

MR. LEITCH: But in the worse case, what we're saying is permission or license to run for 20 years doesn't necessarily assure operation for 20 years?

MR. SUBER: Correct. Correct, the PTS --

MR. LEITCH: We've got this hurdle, 20.17 that we've got to get over, one way or the other, and that issue is not directly resolved now. There may be ways to do that, but today, that issue is not resolved. Is that a correct summary of that issue?

MR. SUBER: Yes, sir, it's a fair characterization.

MR. LEITCH: Okay.

DR. WALLIS: Is there an expectation that there will be a new PTS rule which will make it be okay in the next 20 years? Is that the expectation?

MR. SUBER: Well, that's conjecture and I can't really comment on that.

MR. ROSEN: You probably wouldn't want to invest a lot of money in that.

MR. SUBER: Well, they have several ways of making the rule. Either they can submit their

master curve, have that approved and accepted, and meet the requirements of the rule, or they can hope and pray that the --

DR. WALLIS: You'd better be sure the master curve gets into the record right because it sounds like "massacre" to me.

(LAUGHTER.)

MR. SUBER: That's because it's too close to 5:00 o'clock.

(LAUGHTER.)

CHAIRMAN BONACA: Is the BAW report on the master curve under review right now?

MR. SUBER: I believe it is.

MR. MITCHELL: This is Matthew Mitchell again. Yes, we are still review BAW-2308. We expect, hopefully, to bring that review to conclusion in the not-too-distant future.

CHAIRMAN BONACA: Okay.

MR. MITCHELL: So, I believe we have crossed all the appropriate hurdles and gotten all the appropriate questions answered. It's just a matter of finishing the review at this point.

CHAIRMAN BONACA: Okay, good.

MR. MITCHELL: I would, if I could interject, I would address Dr. Wallace's observation

regarding the potential future revision of the PTS rule. As the ACRS is certainly aware there's been a great deal of work done by the NRC's Office of Research to provide an appropriate technical basis for NRR to consider using to initiate rule-making to revise 50.61. However, in the context of an applicant's approach to using the Triple-I option for a License Renewal Application, we've emphasized, an applicant should base its application on factors which are within its control, not factors which are left to the staff to complete. So that is why you should see an emphasis on exercising the (b)(4) and (b)(7) criteria from 50.61 or 50.66, Thermal Annealing, which is related to (b)(7), within the application. So, if we do, indeed, see this same approach taking in the future by other applicants, you can expect to see a similar type of discussion in those applications.

DR. WALLIS: So your conclusion is that everything is fine?

MR. SUBER: Our conclusion is that the application, with the exception of the open items, is satisfactory to the staff.

CHAIRMAN BONACA: Any other questions for the staff?

(NO RESPONSE.)

CHAIRMAN BONACA: If not, I would like to go around the table and get some --

DR. SHACK: Could I -- I haven't looked at this B&W report. Is this terribly restrictive as far as the amount of available you have to have for particular welds or is this something that's more generically applicable?

MR. MITCHELL: The BAW-2308 report provides -- it's an approach which, if the members are familiar with the Kewanee Application, which was the first successful use of the master curve technology, it's a bit different than that. Framatome/AREVA has chosen to take an approach where they reset the initial RTNDT values based upon master curve data and then couple that to the use of Charpy-based surveillance results to adjust for the affects of radiation on the materials. The approach addresses both specific heats of Lindy 80 weld wire, Lindy 80 welds, as well as provides generic values which could be used for other Lindy 80 welds which were not made from the specific heats which were addressed by the report. So, it has a generic applicability to Lindy 80 materials that could be rather widespread.

MR. LEITCH: One confusion I have, and I'm not sure if we're referring to the same B&W report.

I'm referring to one that's called 2487 NP. This seems to say that if you go through with the power upgrade, eliminate the hafnium, 53 effective full-power years, everything's okay. I don't know if that's -- I mean, that seems to me to be the conclusion that this report draws, yet, having that conclusion, then we seem to back away from that.

MR. RAY: This is Neil Ray again. Let me try to address your question and comments. No, we are not. The point, as Jim Knorr mentioned, is that Units One and Two vessels are so, so embrittled that if you look at Reg. Guide 1.99, Rev. 2, beyond 2.5 times tentative or 19, it is pretty much saturated. So the question you are raising --

MR. ROSEN: It's pretty much what?

MR. RAY: Saturated. All the shift doesn't seem that dramatic. So what happens is even if they take out the hafnium absorber, but just keep it there, it is pretty much immaterial. The reason -- let me emphasize, the reason they committed to keep it, because in the PTS rule it says that you must do some flux reduction program. Since they're exceeding the screening criteria, there is no justification or not that they can take out the hafnium absorber. But for practical reasons, there is no reason whatsoever

to keep the hafnium absorber there.

MR. LEITCH: That helps explain my confusion.

MR. KNORR: This is Jim Knorr from Point Beach. I would like to add a little bit to this. I have a feeling that the report that you're looking at is the upper shelf energy equivalent margins analysis?

MR. LEITCH: Yes.

MR. KNORR: Okay. That is not a PTS report.

MR. LEITCH: Right, yes.

CHAIRMAN BONACA: Okay. If there are no further questions, I thank the presenters, and I would like to just (inaudible 4:57:55) the meeting. The first issue is tomorrow, we'll have the staff, and I believe the licensee, actually he is Senior Vice President of Operations of the site, has asked to make a brief presentation to the Full Committee, five to ten minutes. The other presentation is going to be from Region III, pretty much the one we had today. It is to address some of the concerns that the Committee has expressed regarding performance, the ROP performance of the site. So that will be dealt with tomorrow. We'll have a presentation and it will be a full communication to the Committee. What -- and we

understand also the format of those presentations, again, will be Region III.

What I'd like to do now is focus more on the fundamental elements of license renewal, what we have heard today, go around the table and see if there are any specific insights you would like to communicate. So, we will start with you, Jack.

MR. SIEBER: Okay. In general, it would appear that the application and the FCR are properly done. My own feeling is I do have a concern with this licensee and it has to do with the confirmatory action letter and the most recent ROP findings in that it identifies issues related to problem identification and resolution, and to me, that's the heart of license renewal. You have a lot of new programs, a lot of things that have to be done prior to entering the period of extended license, and it requires good commitment tracking, good problem identification and good resolution. Right now, I lack the confidence that all of those elements are there. I think it's an issue that we need to discuss and perhaps address. I need, personally need a greater degree of confidence than I now have based on what I've read, to believe that all the commitments that are being made will be fully and correctly implemented.

CHAIRMAN BONACA: Okay. Thank you. Bill?

DR. SHACK: I'd sort of walk away with the impression that this is a lower quality license renewal application and assume, with all the precedents that people have, that I would have thought that no questions have to be answered, that just seem to be RAIs asking for sort of basic information, rather than in some cases, clarification. Again, some of the open issues seem to be more fundamental than some of the other open issues that we've come up with. So I'm just a little bit surprised that at this state of the game, this doesn't strike me as one of the best License Renewal Applications that we've seen.

DR. WALLIS: Was it one of the worst?

DR. SHACK: No.

DR. WALLIS: Not one of the worst.

DR. SHACK: No, I think in some ways, it was. I mean, this notion that you have exceptions that you haven't defined. I just don't recall that kind of a situation coming up before and, as I say, some of the RAIs just -- I don't know what the License Renewal Application staff rejections looked like, but this just doesn't strike me as one of the -- as I say, early on, it's clear that we had some confusion over scope and issues and things like that and one could

understand it, but this is a lot of experience to build on here.

CHAIRMAN BONACA: Well, that's a good observation in some respects. Also, our experience in reviewing this has been one of some hardship. I mean, we've been bombarded by paper and paper that has revised existing partial application, providing additional information, et cetera, to the point where, you know, for somebody like ourselves, like for me, operating from my home, reviewing this much information was confusing and conflicting somewhat. So, that is not only the applicant. I think to the parties it seems like the application was more rushed and the SCR, too. There was some pressure in it. That is just a judgment, but I don't know.

Graham?

MR. LEITCH: Well, license renewal, we thought, was getting a more straightforward matter. It seems to me they were all very well prepared and didn't raise many questions. This application seemed to raise more questions than usual, bucking this trend, as my colleagues have said. I was impressed by how many commitments there seem to be, which were to dependent upon the staff making the proper evaluations in the future, and checking that the commitments were

really properly fulfilled.

I was, on the other hand, quite pleased with the way the staff responded to questions today. I thought the staff generally did a good job and gave me more reassurance and in spite of these concerns, things were actually under control. That's something new I don't think my colleagues have said yet, but maybe they don't agree with me. I thought the staff did a very good job today.

I think the Committee has to figure out how far we can decouple the license renewal from the present performance of the plan. I know they are supposed to be separate, but there comes some point when they cannot be separated out. So that's something we have to figure out as a committee, I think, how to handle that on our level.

CHAIRMAN BONACA: Thank you. Tom?

DR. KRESS: Well, I think we have to be responsive to the staff's request that we keep in mind that they are constrained to separate the performance from the license renewal. I think that's part of the license renewal rule. I don't see how we can really buck that. Even though I agree, there certainly are performance issues. I just don't -- I think they have to be handled by the oversight process and not be part

of license renewal.

That said, I think I was given -- like Graham, I think the staff's presentation did give me some reassurance today that they did a good review and that the commitments are there for the aging program and the regions know what these commitments are and know how to inspect for them. So I did get some reassurance there.

The one thing that bothers me about every -- not this particular one, but all of our license renewal reviews that we do, we are more or less just doing a bit of an audit of what the staff does. But my concerns in license renewal generally involve the environmental impact segments. We don't review those at all. I have no idea what the environmental impact of the changing condition at this site over the timeframe is because we just don't review that. That bothers me. I don't know what to do about it, but I think we should, in the future, include that as part of our reviews.

DR. WALLIS: Are you thinking environmental impact other than safety?

DR. KRESS: Well, I'm thinking about mostly safety, but there are other impacts that would be of concern to me.

DR. WALLIS: But you're thinking mostly of safety?

DR. KRESS: yes. That's all I have.

CHAIRMAN BONACA: Graham?

MR. LEITCH: Well, regarding the quality of the application, I think there's a subtle issue here regarding the timing of the inspections and the timing of the issuance of the SER. I think if the SER wasn't frozen exactly when it was, that is, this SER with open items, I think a number of these issues would have been resolved and would have been presented more clearly, had the SER been delayed for, say, two months or something like that, until these issues were resolved. But it seems like there's something about the timing of these events, the inspection, the inspection reports, the audit and review report, and the SER, it seems like all these things came very close together, and I'm not sure whether that's the NRC's scheduling process or the applicant's ability to get information to the NRC or what, but I don't see this as a particularly poor application, but rather, I think there's some confusion by the timing of some of these documents and which one precedes the other, particularly as I say, for a reviewer like me that's off in a corner without understanding the chronology

always of what came first and what input was into what document.

But having said that, I still share some of the concerns that have been expressed regarding the current performance issues at this plant. It seems to me difficult to understand how we could proceed to recommend renewal of the license with an open confirmatory action letter. I realize on one hand, that those issues are within the current licensing basis, and yet, on the other hand, I see us having a responsibility to take a position that's -- that we feel comfortable with and that we feel that we can defend. It just seems to me unreasonable to say, well, you can go ahead and run for another 20 years when there are serious long-standing, outstanding issues.

CHAIRMAN BONACA: Thank you, Graham. Steve?

MR. ROSEN: Yes, thank you. With regard to the quality of the application, I know there was an enormous amount of work done by the applicant and by the staff on this application, and most of it, very, very good. There is one concern I have, having to do with the late re-scoping of the systems, which particularly stands out to me as very troublesome

because then -- I mean, how much confidence should we give to the application when that kind of activity, which is normally an up-front activity, happens at the very last moment almost? It's troubling. I'm not sure where I go with that. But the quality of the application suffers from that.

With regard to the current performance issues, I question that. I'm very uncomfortable wit that as well. I would have to, not repeat what my colleagues have said, but broaden it slightly to say that it's beyond the cap program. There are four other issues in the cap of varying degrees of importance to the license renewal, but some, I think, are particularly important, including human performance, the human performance issues. So I wouldn't limit it to just the corrective action program.

Finally, I do have one tiny technical concern which I expressed some of during the meeting and that is the one-time inspections of the cast iron valves in the fire protection system. It seems to me we miss an opportunity by saying well, we'll do some hardness testing once we get in and look at those valves. The right answer to me is to take a view of those valves out in the one-time inspection, say, ten

years down the road, they're on the ground for sure, but maybe there a couple above ground as well, and they're bolted, I think. So go get a couple of those bolted valves and take a few out and destructively examine them with metallurgical techniques and show that there's no selective leaching going on and that's the end of it. And you wouldn't have to do hardness testing or anything like that. I mean these valves are replaced once in a while anyway, for other reasons. It might not even be a requirement to take a valve out that wasn't coming out for some other reason. So anyway, that's just -- what I heard and what was discussed was just sort of unsatisfactory to me.

CHAIRMAN BONACA: Thank you. I will echo somewhat Graham Leitch's comments with regard to the timing of the SER. I already voiced my concern before. I found myself in a review that I was getting material that was issued before and afterwards was getting additional material, modified information to change that. I could not integrate inspection reports with the other from the lab. Timing was different if I compared -- so there were a number of issues that said to me, if we had received this SER a couple of months later, probably it would be so square and much

clearer to us. And that says, you know, it is important for the SERS to get stuff at the mature stage so that we can give the right judgment. Otherwise, our judgment seems to be affected more by the logistics of how information is provided than by the substance of the application. So, that's something to keep in mind.

Regarding the issue of current performance and license renewal rule, the rule has members that have been very specific all the time about saying we have to separate those, and I still believe that we have to have a separation there. I'm only concerned, however, about current performance as it possibly may affect license renewal commitments. There is a link there. One of the linkages is the human performance issue. If, in fact, there is a significant human performance issue, and we really do not have our own personal inspection, we have to trust what Region III is saying about that, then we have to be somewhat concerned about the implementation of commitments.

I'm not saying that this is not going to happen. I'm only saying that I would have liked to see them out of _____-- before we had to make a judgment and maybe that will happen. I mean, by the time the SER comes, it will be our call, and,

therefore, our issues, moot.

I don't think that there is a sufficient basis for saying that the application should not proceed. In fact, I think that they have made a submittal and we have expressed some opinions about it, but I think that we really need to have some confidence and comfort that, in fact, for all those parts which have not been inspected, and there are many of those, commitments will be adequately implemented. You know, you get a little bit of cold feet when you have a licensee that is in a degraded condition and is essentially struggling to recover. I wish them the best. So, in that respect, there is some connection here and that's just one view.

Tomorrow, we will have our colleagues get the presentation and tomorrow night we will go through a discussion of this SER and where we go with that.

But I want to thank everybody from the staff, from the applicant, for the presentations. They were informative.

With that, unless there are additional comments or questions, I will close the meeting and we'll talk about this tomorrow morning.

Thank you again.

(Whereupon, at 5:16 p.m., the meeting was concluded.)