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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

MEETING OF THE SUBCOMMITTEE ON LICENSE PLANT RENEWAL

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WEDNESDAY,

DECEMBER 3, 2003

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The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 8:00 a.m., Dr. Graham M. Leitch, Chairman, presiding.

MEMBERS PRESENT:

GRAHAM M. LEITCH	Chairman
MARIO V. BONACA	ACRS Member
F. PETER FORD	ACRS Member
THOMAS S. KRESS	ACRS Member
VICTOR H. RANSOM	ACRS Member
JOHN D. SIEBER	ACRS Member
WILLIAM J. SHACK	ACRS Member

ACRS STAFF PRESENT:

MARVIN D. SYKES	Staff, Designated Federal Official
JOHN J. BARTON	ACRS Consultant

ALSO PRESENT:

George Wrobel	RG&E
Russ Wells	Constellation
Ron Clary	SCE&G
Jamie LaBorde	SCE&G
Al Paglia	SCE&G
Bob Wharton	SCE&G
Mike Dantzler	SCE&G
Stan Crumbo	SCE&G
Dave Solorio	NRC/NRR/DSSA/SPLB
Tilda Liu	NRR/DRIP/RLEP
Carolyn Lauron	NRR/EMCB
George Georgieu	NRR/EMCB
Cheng-Ih (John) Wu	NRR/EMEB
Y.C. (Renee) Li	NRR/EMEB
Barry Elliot	NRR/EMCB
Louise Lund	NRR/EMCB
Stephanie Coffin	NRR/EMCB
Pei-Ying Chen	NRR/DE/EMEB
Jin-Sien Guo	NRR/SPLB/DSSA

ALSO PRESENT (Continued):

David C. Jeng	NRR/DE/EMEB
John S. Ma	NRR/DE/EMEB
Thomas Cheng	NRR/DE/EMEB
Noel Dudley	NRR/DRIP/RLEP
Steven Jones	NRR/DSSA/SPLB
Mario G. Cora	NRR/DRIP/RLEP
Greg Gallotti	NRR/DIPM/IEPB
W.H. Koo	NRR/DE/EMCB
Kimberley Corp	NRR/DRIP/RLEP
David Shum	NRR/DSSA/SPLB
Terence Chan	NRR/DE/EMCB
Hanry A. Wagage	NRR/DSSA/SPLB
Duc Nguyen	NRR/DE/EEIB
Raj Auluck	NRR/RLEP
Paul Shemanski	NNRR/DE/EEIB
R. Pettis	NRR
John Fair	NRR/DE/EMEB
Ram Sulland	NRR/RLEP
P.T. Kuo	NRR/RLEP
Hai-Boh Wang	NRC/RLEP
Sam Lee	NRC/DRIP/RLEP
Sam Miranda	NRC/DSSA/SRXB
Caudle Julian	NRC/Region II
Jim Strnisha	NRR/DE/EMEB

ALSO PRESENT (Continued):

Mark Hartman	NRR/DE/EMEB
Wen Change	NRR/RLEP
James C. Pulsipher	NRR/DSSA/SPSB
Russ Arrigh	NRR/DRIP/RLEP
Peter J. Kang	NRR/DRIP
Naeem Iqbal	NRR/DSSA/SPLB

C O N T E N T S

P R O C E E D I N G S

(8:01 a.m.)

CHAIRMAN LEITCH: Good morning. This is a meeting of the Advisory Committee on Reactor Safeguards, License Plant Renewal Subcommittee.

I am Graham Leitch, and I will be chairing this meeting.

Members present here this morning are William Shack, Peter Ford, and John Sieber. We will be joined momentarily by Mario Bonaca and Vic Ransom, and we also have a consultant, John Barton, here with us today. Marvin Sykes is the Designated Federal Official for this meeting.

The purpose of this meeting is to discuss the license renewal application for the VC Summer Nuclear Power Station and the associated NRC Safety Evaluation Report.

During this meeting we will hear presentations by the applicant, South Carolina Electric and Gas, and the Office of Nuclear Reactor Regulation.

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

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register on November 20th, 2003. We have received no written comments or requests for time to make oral presentations from members of the public regarding today's meeting.

A transcript of the meeting is being prepared and will be made available as stated in the Federal Register notice. Therefore, we request that all speakers identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

I should also mention that we have a teleconferencing arrangement and some of the contractors that supported the NRC inspection efforts are on the teleconferencing line.

So at this point I'd like to begin the meeting. I should also mention that we have been joined by Dr. Thomas Kress. I failed to mention at the introduction to the meeting.

So at this point I'll turn the meeting over to P.T. Kuo, who will proceed from here.

P.T.

MR. KUO: Thank you Dr. Leitch.

Good morning. My name is P.T. Kuo, the Program Director for the License Renewal Environmental Impact Program. I have with me today also on my right Dr. Sam Lee, who is the Section Chief for Section A, License Renewal.

Today's staff presentation will be led by Dr. Auluck, Rajender Auluck on my far right, and then he will be assisted by Kimberly Corp, sitting on my back.

There were no open items on some review as a result of the staff review and the inspection. Dr. Auluck will discuss a few issues with the ACRS members, and then we will present a couple of examples of one time inspection as requested by the ACRS.

After that, we have also Mr. Caudle Julian here from Region II, and he will present his inspection findings and also describe the plan's ROP status for the ACRS members.

Let's see. I guess with that, I would like to, if there's no further questions, I would like the applicants to proceed with their application first and follow with the staff presentation.

MR. PAGLIA: Okay. Thank you, P.T.

Good morning. I'm Al Paglia, and I'm supervisor for the Plant Life Extension Project.

And I'd like to begin by presenting, first of all, the overall licensee project manager for this project. To my left I'd like to introduce Jamie Laborde as the mechanical lead for the NSSS.

Sitting over here is Mike Dan Dantzler, who is the mechanical lead for the VOP.

Bob Horton, who is the lead for civil and structural, and Stan Crumbo is the lead for electrical.

What I plan to do this morning is cover just a few topics. I'm going to go briefly over some background and history on this issue, and I'll talk about some issues I think that are of particular interest, and I'll just touch on the application there. I'll try to answer any questions you may have, a few statistics on programs, and then talk a little bit about a tracking program and what we plan to do in the program.

As far as background, as you probably are well aware, we are a three-loop (phonetic) Westinghouse plant, 1,000 megawatts electric nominal, and our license was granted in August of 1982.

South Carolina Electric and Gas is a two-thirds owner and licensee. Santee Cooper is the South Carolina public utility. They own one third. Note we

did change out our steam generators to Westinghouse Delta 75 steam generators in 1994.

Following that in '96, we did upgrade the plant from 2,775 to 2,900 megawatts of thermal.

And as far as the oversight process, right now all of our performance indicators and inspection findings are green.

MR. SHACK Could your steam generators support an additional up rate if you wished to in the future?

MR. LABORDE: Yes, they could. The generators are, in effect, the design from the AP-600, and the generators themselves are rated at about 1,000 megawatts thermal each.

MR. PAGLIA: The issues that I plan to talk about a little bit, and I know you have some knowledge of our alpha hot let crack that we had, and I'll just touch the highlights and try to answer any questions that you may have. I'll talk a little bit about the upper and lower inspection results. There's some blockage both in response, and then I'll talk a little bit about the philosophy on one times (phonetic), and I think the staff is going to present the major body of that information, and we'll support them.

On the alpha hot leg, again, as you probably already know, what we did was cut out that weld. We cut out a spool piece that was a little over a foot long and did destructive examinations and metal approach examinations to understand the cause.

What that cause ultimately was was determined to be attributed to a high tensile stress on the ID of the pipe and from the original installation weld.

MR. BARTON: Was that weld in your ISI program in crack not detected or --

MR. PAGLIA: That's correct. It was, and it was not detected.

MR. SHACK The other thing that was curious to me about that, it wasn't covered in your boric acid corrosion program initially either, was it, at the time?

MR. PAGLIA: Well, our boric acid corrosion program encompasses, of course, walk-downs that we do when we initially shut down the plant for outages, and we look for all sources of boron. Now, what we don't do is remove insulation, and at the previous outage, there was no evidence of this.

Now, on start-up there is a surveillance that requires us to take a look for any leakage at

normal operating pressure. That we also do and do every outage, and there was nothing noted at that time.

So this lead did really propagate to fruition, if you will, and leak through the outage. There was some very site -- you know, some attempts to characterize when that occurred. It wasn't exact, but it was determined that it probably started after we had started up. It came through wall after we had started up.

MR. BARTON: Well, if this was on the ISI program not detected, I guess that raises my question of, you know, how good your ISI program is and what did you do when you found this crack? Did you go back and look at other --

MR. PAGLIA: Yeah, let me try to go forward here.

MR. BARTON: Can you tell me what you did?

MR. PAGLIA: We've done quite a lot actually in that regard to try to figure out what we have and to the extent that we have it.

I made this note here that at that time, in that outage, we, of course, looked at all five other nozzles. We did it both with eddy current technology, which was not, you know, a qualified

process when it was something to provide information to us, and we did UTs.

And we found, at that time, a number of indications via the eddy current technology. We did not find anything with UT, nothing reportable. We actually didn't find anything in UT, but we did find those indications.

Now, let me carry forward because I think I have kind of the remainder. I've got a little graphic here. Again, you may be aware of this, but I wanted to show it to you anyway, how this problem really began.

This is a reactor vessel nozzle. This is the cladding on that nozzle, and this is the butter, the ICONEL butter and, of course, the loop pipe, and this is just the normal weld prep for this kind of situation. So this is the starting point.

And, you know, these passes are laid in. They're about a tensile width thick. They are many passes, probably 100, to go from here to here. Maybe 100 of the first number of passes go here.

This weld was rejected based on indications that were identified, and so this bridge was established to stabilize the pipe, and following that, then this original weld was excavated, and we

excavated the land area as well. Okay?

Now, this was done at 360 degrees around the pipe. Okay? There were other repairs associated with this weld, but this is the principal one and the one that we feel dominated the scenario.

Then we reapplied this weld, and we did it from the bridge to the ID, and then came out later and went from the bridge to the OD, and then the end result, and this graphic, by the way, isn't to scale. I'll show you an actual cross-section in a second. This was what it was supposed to be, and this was what we ended up with.

Now, I think you also know as you lay these welds in and have weld shrinkage, it puts the lower welds in a compressive state. That's the concept, and by design, in the end, the ID is in a compressive state for the purposes of reducing tensile stress.

This next slide shows you the actual dimensions in cross-section. Again, nozzle, butter, weld and pipe. This was a blow-up of this area here, and this was the excavated area where it was relayed back in, and there was your tensile stress that we think drove this PWSCC forward.

We had all of the conditions at that

point. Before the stress we did not. So we feel like by replacement of the weld, the spool piece and using proper welding techniques we've eliminated that problem. We've not eliminated PWSCC, but eliminated this particular issue.

Yeah, go ahead. Comment?

MR. LABORDE: On your question about the boric acid inspection, the actual way we found this was a boric acid inspection.

MR. SHACK Yeah, but it sounds sort of like it was an accident, that you really weren't looking at this. You then included all of the 182 butters in the boric acid inspection program, and I would have thought that, you know, that would have been one of the first things that would have gone into my boric acid inspection program.

MR. LABORDE: The way our program is written, we basically go in and examine everything in the reactor building, and it's just now we're a little more specific at looking at that, being careful to look at that, but automatically we would go into all areas and look for evidence of leakage, and that's how this was detected, because of those efforts.

MR. PAGLIA: Yeah. In effect, nothing is excluded per se.

MR. SHACK: No, it's a question of where you do focus some attention.

MR. PAGLIA: Yeah, sure.

MR. BONACA: Now, will future inspections of this area fall under your alloy 600 program?

MR. PAGLIA: Well, we'll get to that, but the alloy 600 program essentially right now is comprised of the ISI program, our chemistry program, and we've agreed to obviously implement any recommendations that come out of the MRP and future OE in this area, but at this point -- and I'll show you what we did in 13 and 14 -- we are doing code required inspections going forward.

I think we got some good news, frankly, in 13 and 14. In 14 --

MR. BONACA: No. I'm sorry. The reason why I'm asking that question is that you are reading about your alloy 600 energy management program. You take an exception on goal by indicating that you would not rely on enhanced leakage detection system for detection of small leaks caused by primary water stress corrosion cracking.

And I was trying to understand what this statement means in the context of this program.

MR. LABORDE: Right. In the context of

that program, I think when the GALL was written, there was indication that we would use a monitoring program to detect leakage that was not in place, and I think since then there has been some, I guess, radioisotope type of analysis done with rad monitors that I think is a little more effective than the methods we originally used.

But the thought process when we wrote that was that we didn't have a method better than the monitoring program we had already established on monitoring water level on sumps and condensate from drain coolers, et cetera.

MR. PAGLIA: And the other thought process is that that's not really an aging management program. Leak detection is really fault finding. Fundamentally we're looking through ISI and maintaining good chemistry, that we see things hopefully that will become limiting.

MR. BONACA: Well, when you say ISI, that includes --

MR. PAGLIA: Fundamentally UT inspections on those welds.

MR. BONACA: Yeah. It includes volumetric inspections.

MR. PAGLIA: Yeah, volumetric.

MR. BONACA: In fact, you also use eddy current as a lead inspection to identify where you may have superficial cracks. I just was confused by the writing of your program. When I read it, I read that you are now going to perform volumetric inspection. That's what I understood, and so this clarifies it. Okay?

MR. PAGLIA: Okay.

MR. BONACA: And I just couldn't understand where you were going with that. So that's not true.

MR. PAGLIA: That's not true. That's not true.

MR. BONACA: So you do have a comprehensive problem consistent with GALL, really except for that exception.

MR. PAGLIA: That's correct. That's correct.

MR. BONACA: Okay. Thank you.

CHAIRMAN LEITCH: So on that point, and maybe this is more a question for the NRC, but I thought I read in the inspection report that you were not planning to do eddy current inspection of the B and C hot leg welds at the upcoming outage. Is that correct?

MR. PAGLIA: Well, what we did do, we did do eddy current in 13 and we did do eddy current --

CHAIRMAN LEITCH: Thirteen was?

MR. PAGLIA: Thirteen was the last outage. We just completed refuel 14.

Now, let me back up a second. Without trying to get too much detail, we took those -- that spool piece that we took out, we did destructive characterizations and characterized all of the flaws that we identified, and we came to understand the aspect ratio, the length and depth relationships.

We took the worst case relationship and applied it to the eddy current indications we identified in the other five loops. I think all but one had some indications, and we then inferred a depth. Because you may know that eddy current only gives you surface length essentially.

And then we applied crack growth methodology on top of that. And the SER for start-up out of 12 was based on the fact that those flaws applying this worst case approach would not grow to a limiting fault in two cycles. Okay?

We came back in 13 and we did Bravo and Charlie hot legs only. The lower -- the cold legs required to remove the lower internals, and we did

choose to do that for 13.

Now, in Bravo and Charlie in refuel 13, we did identify two recordable indications, one in Bravo 1 and Charlie. What we did in 13, because we were trying to figure out how to reduce the probability of this to occur in the future, we applied what's called the MSIP process. It's mechanical stress reproduction improvement process, hydraulically basically compressing the pipe and cost of bending on the ID to reduce that tensile load.

We did that. Now, once we did that, the indications that we had were pre-MSIP, most MSIP. The one indication that was reportable on Bravo hot leg went away. It became invisible. It didn't go away, but it became invisible to UT. The other indication remained visible.

CHAIRMAN LEITCH: On Charlie.

MR. PAGLIA: On Charlie.

Now, we came back basically on that basis and on the fact that we had done a mitigative procedure. You know, the SER, that's how we started up from 13.

Coming into 14, which is our ten-year, full ISI program, now we went back and looked at everything again. We looked at everything with VT.

We looked at everything with UT, and to, you know, a pleasant surprise, everything that we had identified originally was reidentified. We could trace; we could correlate, and there was no growth. Nice to be able to say there was no growth among all of the indications that we had found, and there were no recordable indications under UT.

Another fact that was a nice surprise was that that Charlie loop indication that we had, because techniques got better over this cycle, we were able to determine with UT that it was an embedded flaw, not a surface breaking flaw, and it was about a .43 inch ligament between the ID and the flaw.

So because it was imbedded and it did not meet recordable characteristics, so it's really a nonrecordable flaw.

Now, because we had that Bravo hot leg flaw that went away after MSIP, but it was recordable, we are obligated now to accelerate now on that nozzle weld for the next three ISI cycles. So every two outages we'll hit that. And then beyond that, we'll drop back to strictly the code required inspections.

For all other loops we are now committed to just code inspections, and that's what the SER that we -- authorizations we just received after review of

the 14 days.

So that's where we are. Right now we think we have arrested the situation. We don't know that we solved it, but we've arrested it, and right now the data is looking favorable.

CHAIRMAN LEITCH: Now, was it the floor in B, "Baker," disappeared, was undetectable?

MR. PAGLIA: Yes.

CHAIRMAN LEITCH: Is that still undetectable in 14?

MR. PAGLIA: Correct. It is still undetectable. That's correct.

CHAIRMAN LEITCH: Now, the two new welds on A, where you welded in the new piece, what kind of an inspection program applies to those?

MR. PAGLIA: Code inspections.

CHAIRMAN LEITCH: Just code inspections?

MR. PAGLIA: Yes, code inspections. Again, what we did there, we had to rebutter the nozzle, but we also butted the spool piece. So the spool piece had to stay in the stainless weld, and then it had an INCONEL-to-INCONEL weld. Actually that's what went back in.

MR. CLARY: And since we were in 14 at the end of the ten-year ISI and so we did the vessel

inspections also, we looked at that alpha hot leg with the UT and eddy current this time.

CHAIRMAN LEITCH: Okay.

MR. SHACK: Now, when you say you're back to code inspections, I assume that you're still using the actual technique as something that you've qualified as being able to detect. I mean, you missed it the first time, and you changed your UT techniques and you finally were able to see it again. I assume you're using -- you're committed to using the improved UT.

MR. PAGLIA: Well, yeah. I'm not a UT expert here, but I will tell you that, you know, the code required inspection is with UT technology, and I know that there are increasing requirements on UT technology, performance demonstrations that have to be made.

We were able to make some improvement, but could not meet the fully new requirements for the performance demonstration, but what we agreed to do and what we will always do in the future until we improve the technology is we take that margin that we couldn't capture, that accuracy we couldn't get, and just put it on top of what we find and calculate from that point where we are and where we can be.

That's our approach. I think that's pretty much an industry-wide approach right now. This technology has been pushed to the limit, and we just have to wait till we get these probes down to the point where they can follow the surface profile in closer so that we can get the detail that we want to get.

MR. BONACA: Well, that was my next question, in fact, you know, how the industry is learning this experience and applying it in detection. They are doing it.

MR. PAGLIA: Yes, they are doing it. It's very active, very active in it, and there's progress being made, and it fundamentally centers around the sizing and the profile following of these probes.

MR. BONACA: In fact, when I was reading the alloy 600 problem, there's a statement that says, "Conclusion. The Alloy 600 issue in my report has been demonstrated to be capable of detecting and managing cracking."

And, you know, this is the place where I would have liked to see a statement that said there were problems and we have learned from this, and we think we're doing better. Hopefully that's really where we are.

I mean, the whole industry is in that direction. But I'm not taking any objection to the exact writing, but I hope that the lessons learned have been truly applied here.

MR. PAGLIA: Yeah.

MR. SHACK: But your history explains to me why I can't find MSIP in the license renewal application. You really weren't going to do MSIP until you found the indication in the Baker leg; is that --

MR. PAGLIA: Well, no, actually not true. Once we, of course, have out the hot leg, you know, everybody is involved in this thing and going forward. We knew we had to do some things to reduce the probability of it occurring again, and one of them was mitigative repair.

And one of the proven concepts before was MSIP. It wasn't new to us. However, the sizing of it was new. Nothing had been done that large.

MR. SHACK: Yeah, but nobody had done this on a PWR pipe before.

MR. LABORDE: When we wrote the application originally, we actually started writing prior to discovering the crack. We rolled some of the information into the application, but certainly not

all of it.

MSIP had not been done on PWR, only on BWR.

MR. LABORDE: It's been done on big, big pipe, yeah, but not the wall thickness you guys have.

MR. LABORDE: And it has not been done in this kind of situation. So I think we had to go through an evolution to I guess you would say qualify the process on the pipe, on our pipe. So it was a while before we knew that we could, in fact, do that process.

MR. SHACK: Now, was that an analytical verification or did you actually make measurements of plastic strain on comparable joints?

MR. PAGLIA: I believe -- I am not totally familiar -- I believe they actually had done it in a shop type setting to confirm they could do it.

MR. PAGLIA: I believe that's correct.

MR. LABORDE: But I was not involved in the process.

MR. PAGLIA: I don't think we took strain measurements on our particular --

MR. LABORDE: No, we didn't.

MR. SHACK: But there was a mock-up kind of arrangement?

MR. LABORDE: Yeah, we did a mock-up or there was a mock-up done and they tweaked it to verify that they could get the results.

MR. SHACK: And then you do have a full analytical study for your particular configuration.

MR. LABORDE: Sure, right.

MR. PAGLIA: And, again, you know, that's the theory, and we think we reduce some stress. I mean, I don't think we can say we've eliminated it, but the results are in the results, and right now it's favorable based on the lack of growth primarily. That was a real positive sign they thought.

CHAIRMAN LEITCH: Did I understand you to say that you were planning on mechanical stress improvement even before the crack was --

MR. PAGLIA: It became a plan. You know, there was a big effort kicked off obviously after the hot leg. The whole point I was making is that we didn't wait for Bravo to do this. All of these actions were kicked off out of the hot let, Alpha hot leg episode.

CHAIRMAN LEITCH: Oh, okay.

MR. CLARY: The fact that we found the Bravo indication was just more data, more data. And, you know, there's differences, and this technology

isn't perfect. So you've got some variation when you apply it. I mean it's not 100 percent.

And then the other thing that was evident was the UT process and eddy current process improved from 12 to 13 and from 13 to 14. So, you know, that indication in the Bravo hot leg could have been there in 12. We just didn't see it, and then we saw it as the UT process was better.

CHAIRMAN LEITCH: That's right. That's right.

MR. PAGLIA: So that's the hot leg story. If you have got any other questions, I'll be glad to hit them later if you want.

All right. Moving on to head inspections, for our upper head, you know, as a result of the bulletin that came out in 2002 and Davis-Besse and so forth, what we did in refuel 13, we did a best effort bare metal inspection of the head. We went to all accessible areas. We did user mode optical device, robotics device that went around under the insulation.

We did find some accumulation of boron. These came as we determined from an earlier conoseal leak that occurred at the end of refuel 2 and refuel 3. That was subsequently repaired in refuel 4, and we had no leak since. It's just where the thermocouple

extension wire comes through and is sealed at the top of the whole conoseal assembly.

There was some residue remaining. It was a thin film that occurred at cold, low temperatures, not considered aggressive and, you know, it wasn't cleaned up perfectly, but that's what we found.

And obviously, no active leaks or degradation was found. There was no boron in direct contact with the head.

In 14, we went back and this time we did 100 percent bare metal. We did remove the insulation where it was required, and we did use a similar device and no active leaks or degradation. You may know that we are a low susceptibility plant. We have a T-cold (phonetic) head and think we would be later --

MR. SHACK: You've been cold since day one, right?

MR. PAGLIA: We've been cold since day one. So, you know, we're vulnerable, but we should be toward the end of the list.

So that's how --

CHAIRMAN LEITCH: So is this inspection in compliance with the NRC order?

MR. PAGLIA: Yes, I think we're in full compliance with the requirements of the BOLTA

(phonetic), and if they go --

CHAIRMAN LEITCH: You didn't have to seek relief from some facets of the order?

MR. PAGLIA: No, and primarily, I think, because we were able to do 100 percent load, and we're going to look again. We're not stopped here.

CHAIRMAN LEITCH: So there are no plans for head replacement at this unit then?

MR. PAGLIA: We don't have any specific plans. We have done some very preliminary looking at the availability of material and so forth, but we have no plans specifically in place.

CHAIRMAN LEITCH: Okay.

MR. PAGLIA: On the lower head, again, we went down this outage. Again, we normally would go through. We do a walk through this NCORE (phonetic) pit. We look as part of the normal boron walk-down as well as the start-up surveillance for leakage. That's what we have always done at every outage and never saw anything.

This time we went in and we did do a 360 degree, 100 percent inspection of all of the penetration of the nozzles, instrument nozzle penetrations from the bottom. We did find some dry boric acid. We found some that looked like it had

dripped down the side of the vessel and to some of the nozzles. We found some rocks on the NCORE pit floor.

We did a chemical analysis, tried to characterize it. You know, basically, again, as you may be aware there was no Cobalt 58. There was no Cesium 134, no iodine. So it was considered not an active leak. I mean, it had been there a while, and radially this dripping down the side of the vessel was under the alpha hot leg, and we also think that probably in refuel 13 there may have been some leakage from the refueling cavity. You've got a seal between the vessel and the cavity, and there may be some leaking down through there.

So we cleaned it up real well and pressure washed it. We've got a video record of it. We've identified all of the penetration nozzles on the record. So now we have a very clean baseline to go from for future inspections and comparison purposes.

And that's the lower head. Right now we're okay.

On the sump blockage bulletin, there are a number of things we responded with option two. We, you know, discussed the various compensatory measures that we have in place, I think, which was satisfactory. We did obviously go down and do a walk-

down in accordance with the NEI guidance. What we did find was some original installation gaps. They weren't significant, but they were there, and we repaired them and closed them up.

There are some doors over the sump. They have, if you will, regular hinges instead of piano hinges, and between the hinges you've got a space. The gap was only a quarter of an inch, but the length was obviously more than a quarter of an inch, the screen-to-fine screen mesh is a quarter by a quarter. So we had greater than the spec on the gap.

Also, at the top of the fine mesh screen where it would intersect with the door there was a half inch gap instead of the quarter inch gap, and that was also closed.

Also, one other thing, there was some level instrumentation that was inside the screens before, with cabling running through conduit, and that was removed to the outside. The conduit was removed, and the hole in the screen remained, and so we closed it up.

So we repaired those gaps. The general overall material condition of sumps is very good. Bob has got some pictures if you're interested, but it was in good shape.

Some other things that we did looking forward and where we're going, we did some latent debris collection, sampling. This is just debris that would come fundamentally out of the ventilation system during the cycle and would be in containment, and we did that for future design studies that we're going to do on debris generation and transport to put to bed analytically that the strains (phonetic) and the design can handle it.

We are going to apply some new guidelines that are put out by NEI, and we are going to evaluate the adequacy of the surface area to available screens, being sure that they are sufficient.

If they're not, we will make mods. The mods are planned for refuel 16, and that should be ahead of -- which I believe is the NRC target for closing 191, which is the end of 207. So that's our going forward plan on the sumps.

CHAIRMAN LEITCH: Have you been able to do any modifications to operating procedures to mediate properly?

MR. PAGLIA: In the bulletin -- I don't have these details, but what we did is we basically provided what we currently do. We made no other changes to the way we do business. We did provide a

defense for not early termination of spray. We did that based on the conflict with the ERGs. I know that's an issue of interest, and what we have committed to do, and there's a study going on now to reevaluate early termination of spray, you know, before you would reach SI termination criteria, to determine if that can be done, and that study is scheduled to be completed in March of this coming year.

And whatever the results are, we're going to obviously evaluate and take appropriate action, but I think what we currently do meets the intent of what was required in the bulletin.

MR. KRESS: What kind of insulation do you have?

MR. PAGLIA: Jamie, do you want to speak to that?

MR. LABORDE: The insulation inside containment is predominantly reflective metal. We do have some other types of insulation, but they're encapsulated in stainless steel jacket.

MR. KRESS: Is your containment well painted?

MR. LABORDE: Yes, it is. We do have coating.

MR. PAGLIA: Yeah. There was no issues with coating. There were some minor issues that Bob can speak about, but around the interface between the floor, nothing; no big doubling or anything going on in there.

CHAIRMAN LEITCH: You had some evidence of some flaking of --

MR. PAGLIA: At the floor interface?

CHAIRMAN LEITCH: And those of the upper region, I thought.

MR. PAGLIA: Yeah. bob, do you want to talk about that a little?

MR. WHORTON: Bob Whorton, structural engineer.

As part of our maintenance rule inspections and the IWE and IWL containment inspections, we have now a well documented baseline of all the coatings of the liner itself, and in the dome area, we have just identified some very minor -- a split in one location and a top surface flaking, and we're talking areas of less than two square inches that we can identify through high power telescopes and lighting.

At the intersection of the moisture barrier on the base floor is where we have identified

some light rusting in that area, and we've addressed that as part of a nonconformance notice program and done evaluations.

MR. KRESS: Do you consider this issue a license renewal issue or is this something that you just did for comfort to satisfy the --

MR. PAGLIA: The sump issue?

MR. KRESS: Yeah.

MR. PAGLIA: Well, no. I think it's really current licensing, but it's meeting design basis functions today. I mean, the aging is really not the issue.

MR. KRESS: But it was just an interest in this license renewal.

MR. PAGLIA: Yes, right. Okay?

Okay. If there are no other questions, we'll talk a little bit now about one time, and again I'll give you a little philosophy, and then we can talk in more detail about the specific inspections later if you'd like.

There are nine programs that we identified as one time inspections consistent with the GALL, and for all of these areas where there were aging effects that need to be managed, there were no existing programs that we could credit. Okay?

We applied this one time inspection technique, and you know, we took this from the GALL and said this fits and we'll use it. This is how we'll do it, and what we'll do is we'll go out and typically I think we've tentatively planned by year 35 time frame, if not before, and do an actual inspection to determine if these aging effects that we identified as potential actually exist.

And if they exist and if there's anything measurable or significant, we intend to do further inspections. We will enter into a corrective action program and carry forth from that point.

So these are more than likely not one time inspections, but that's how we're starting out. We did use this approach, and I think in all cases, and we have some data to support this, where we very conservatively identify that these aging effects would occur, and second, these aging effects that we're talking about are expected to progress very slowly. If we go in and find otherwise we'll obviously take necessary action.

Again, we have some detail on specifics if you'd like to talk about it or we can certainly wait and walk about it when the staff is going to present this information.

CHAIRMAN LEITCH: Well, some of them, like the diesel generator systems inspection, I'm just curious. I know you do inspect these generators. You certainly look at active components.

MR. PAGLIA: Right.

CHAIRMAN LEITCH: I thought you had also some inspection activities looking at passive components. So how different in this case would the one time inspection be?

MR. PAGLIA: Okay. Mike, do you want to address that?

MR. DANTZLER: Mike Dantzler.

Now, we have other programs. The diesel generator inspections, the one time inspections are material-environment combinations for which we didn't have a program. Now, they're very specific, and they're very specific components. Okay? It's the interior of the starting air tank. It accumulates moisture.

So we don't expect it to occur quickly, but we're going to look at it. There should be some general corrosion. And conservatively we said there's some alternate wetting and drying because operation shifts will blow down a little bit of moisture every shift. It's not really driven by any heat or

anything. It's not accelerated dry. It just fluctuates a little.

So we couldn't rule it out. So we put it in. We're going to look at it.

There's also some exhaust air we're going to look at, and our diesel generator is a standby. So normally the predominant environment is just filtered air. Sometimes we'll run it and it will be exhaust air. So we can't rule out aging effect. So we put it in.

CHAIRMAN LEITCH: Okay. Thank you.

MR. PAGLIA: Okay. On the application I really don't have a lot. I wasn't going to go into any detail here. Obvious it was put together according to the Reg. Guide 9510, SRP, and did GALL comparisons as you know.

On programs, just some statistics. We ended up with 45 programs that were accredited for license renewal. Twenty-nine of them were existing, six of which needed some enhancements to be broad in consistency with GALL.

Of the 23 existing, 15 were already consistent with GALL. These are essentially regulatory required CLB programs, and there are 16 new programs that were identified, 13 of which will be

consistent with GALL.

On commitment tracking, we have entered all of the commitment into our station tracking system, identified future actions and assigned responsibilities. As far as the overall management of that, we are managing it similar to other regulatory commitments.

We are really not treating license renewal particularly different. The licensed organization remains responsible for regulatory commitments and retains the overall approval authority. That's how our system works, and they assure that the intent of the commitments are met when the action items come back in in the organizations.

So that process will continue, and all of these commitments are in that system.

CHAIRMAN LEITCH: There's a comment in the inspection report dated 9/29/03 that, I guess, the inspection was actually done a month or two prior to that time, but the report was dated the end of September. It says that the tracking system has not yet been established.

What does that comment mean?

MR. PAGLIA: The wording is not correct in the sense that the system that we are using is the

existing system. We at that time had not loaded these commitments into that system, and that has occurred, and I think Caudle will speak to that in a little while.

CHAIRMAN LEITCH: Okay.

MR. PAGLIA: But we did not create a new system. It is simply our -- in fact, we call it condition evaluation report. The software is a PIP (phonetic) system that we, frankly, bought from Duke years ago. It's our one stop reporting. We report everything into it. Our regulatory commitments are specifically identified. License renewal commitments are specifically coded.

So you can go into that system which has thousands of --

MR. BARTON: It's a common system for --

MR. PAGLIA: It's a common system, yeah.

MR. LABORDE: And, frankly, we wanted to wait until we had the SER to write our commitments up to agree with the SER. We thought that would be easier and cleaner for the regulators to come in and track against.

CHAIRMAN LEITCH: Okay. Well, I'll ask the staff to comment on that when they get their turn.

MR. PAGLIA: Okay. Now, as far as the

living program, the one big item that we still have left to do is we're going to put together a license renewal design basis document. This is going to be something we decided to do internally. It's going to be a compilation. It's basically the story and the essence of what we did and why we did it, but it's also going to include importantly the implementation guidance for the future commitments that aren't clear, crystal clear.

And so they'll be housed in this DVD, and engineering in the future, when those things come down to implementation, will take advantage of existing OE obviously, techniques of the time, et cetera, but using these, just this implementation guidance which will be bounding to insure that we meet the intent of the commitment once it's implemented.

And we need to distill this form our basis documentation. This is a process that we haven't yet done, but we will as a project complete that before we break up next spring.

Commitments that are implemented through procedures, those commitments are identified in procedures, again, not new to license renewal. This is the way we do business, and they are tracked back to their base documentation and are a regulatory

commitment.

The procedure changes are obviously controlled under 5059, and we are going to go into our configuration and control procedures, our engineering change processes and include steps and guidance to assure that we continue to meet the requirements of Part 54 down the road for review of the need for aging management in the application of appropriate programs.

That's also a piece of work that we will complete prior to closure of the project.

CHAIRMAN LEITCH: Just a question there about the corrective action program. Is that a separate program or when you're talking about your commitment tracking program, does that include --

MR. PAGLIA: Yeah, it does.

CHAIRMAN LEITCH: -- that corrective action?

MR. PAGLIA: Because that commitment program, if we had an event occur in the plan or find something in a failed state or we have a regulatory commitment, we write this; we identify this, and there's a description page that describes the event.

And then there is a condition evaluation, and in that condition evaluation is where engineering, typically engineering, would evaluate the disposition

of that item.

We have procedures in place for varying levels of root cause analysis depending on the severity. The CERs are categorized one through five, and that drives the root cause process or a little lesser detailed approach. That's the corrective action program.

Now, if we went out under a one time inspection and we identify aging, by definition by our program it's going to be off normal, and it will require a conditional evaluation. That conditional evaluation may not be a root cause per se, but it's going to drive future inspections so we can properly characterize it and understand what's going on.

MR. BARTON: Because you have one corrective action system at the station.

MR. PAGLIA: Exactly.

MR. BARTON: Is that what I'm understanding?

MR. PAGLIA: Yes, sir.

MR. BONACA: We have two types of commitments right now that you have to track. One is commitments to implement programs that you will use during the license renewal period, and that also includes, for example, completion of your TLAs

analysis, whatever you have committed to do.

MR. PAGLIA: That's correct.

MR. BONACA: And then you have commitments to execute the program when you get into license renewal. Are you keeping those two commitments separate? I mean how do you --

MR. PAGLIA: No, we don't really characterize them differently. I mean, you're right. There are different types of commitments to go out and create a new program and implement it, to continue to implement an existing program, and that's where we will now include in procedures that drive those programs. It's called our procedure commitment accountability program. We will annotate those steps or the scoping statement of the procedure to indicate that this is a license renewal requirement, and it will refer back to that DVD that I said we were going to generate so the person that wants to change that procedure down the road would have to go back and reconcile it with DVD.

MR. BONACA: When you answer the question, it is that the NRC will come and inspect you before you get your license to verify that the first group of commitments have been, in fact, implemented.

MR. PAGLIA: Sure.

MR. BONACA: According to your commitments. I mean to what you said you would do.

MR. PAGLIA: That's why I said earlier that the licensing organization remains overall approval authority. They're the group that will, regardless of who is in the seat, will assure that those commitments are met prior to that period, and we fully recognize that the staff in the end will comment.

MR. BONACA: Right.

CHAIRMAN LEITCH: So as I understand it, although you have one program, you could sort on license renewal commitments there.

MR. PAGLIA: Yep, you sure can.

CHAIRMAN LEITCH: So they're all coded. We won't lose them.

MR. PAGLIA: Yeah. Okay. Well, that's all I had, I think, formally prepared.

CHAIRMAN LEITCH: I wondered if just to help me a little bit if you could give me a little bit of discussion of the rural water situation. In other words, just what does the plant look like?

I read a lot of discussion about the pump house, the dams, but I didn't have a good physical picture in my mind of what was going on. They talked

about the dam's retention dykes. What's all that about? Can you give me just a two minute thumbnail sketch of what the --

MR. PAGLIA: Let me defer to Bob, I think. He can give you all you need.

MR. WHORTON: This is Bob Whorton.

It might help if I give you like a layout of some of the features of the plant just to orient you. Okay. This is a general layout of the plant site, and as you can see here, we have the Monticello Reservoirs, the once through cooling for the nuclear plant. It also --

MR. SIEBER: You have to use the microphone.

MR. WHORTON: We have Monticello Reservoir, which is the impoundment for the cooling of the nuclear plant, which also serves as an upper storage pond for the Fairfield pumped storage facility here.

The service water pond is a 44 acre surface acre pond, which is our safety related impoundment, and it is enclosed by a north dam, a west embankment, a south dam, and an east dam.

The north berm that we've been talking about is non-safety related -- I'll call it a dyke.

It's just an earthen embankment that was put in primarily for the severe flooding under hurricane PMP situation, probable maximum precipitation.

The other dams of the Monticello Reservoir are all non-safety. They're four dam, Dam D, C, Bravo and Alpha is up to the north. So that's the general layout of the plant facility.

CHAIRMAN LEITCH: So the general elevation of the ground is higher than the Monticello Reservoir?

MR. WHORTON: Yes, sir, the general site area is at elevation 436. The maximum impoundment of the reservoir is at 435 -- it's 425. I'm sorry. Four, twenty-five.

So we have I think it's 11 feet of height, elevation above that. The lower river, the Board River is well below. It's several hundred feet lower. So the only flooding potential that we have is this natural impoundment.

So this north berm right here was installed primarily for those several hurricane winds, PMP situations.

CHAIRMAN LEITCH: Now, there's a pump house. Could you show me the location of that?

I'm just a perfect straight man to you.

(Laughter.)

MR. WHORTON: My next slide.

MR. BARTON: Before you get to that, you've had some hurricanes to that area. What's the maximum level the reservoir has gotten to?

MR. WHORTON: The reservoir was formed as part of a pump storage facility. So it operates normally between elevation 420 and 425. We can control that elevation. So 425 is the maximum.

Hurricane Hugo, when it came into South Carolina in '89, came in probably 50 miles to the east. So the winds did not produce any significant wave run up in that location.

MR. BARTON: Okay.

MR. WHORTON: So we've never had any severe phenomenon at that summer station at this point in time.

MR. BARTON: Thank you.

MR. WHORTON: The service water pump house we're talking about is on the west embankment of the service water pond. This is actually a dam, but the site boundary comes up to form the surface there.

CHAIRMAN LEITCH: Now, is that circulating water or is there safety related water in that?

MR. WHORTON: The service water pump house is the safety related part of the system, and

circulating water is there.

CHAIRMAN LEITCH: It's that other pump house. Okay.

MR. WHORTON: Which isi the non-safety.

CHAIRMAN LEITCH: Okay.

MR. BONACA: That's the area where you experienced settlement, right?

MR. WHORTON: Yeah.

MR. BONACA: Significant settlement.

MR. WHORTON: Know the surface water pump house and the intake structure are where the settlement occurred in the early part of construction, and we can talk about that in detail if you'd like.

CHAIRMAN LEITCH: Yeah, I was kind of curious about that. I guess as it impacts, you know, the joint, but I'm picturing that there's piping running from there into the plant, and there's a differential movement occurring there.

MR. WHORTON: I don't have a viewgraph showing the details of the pump house, but there's a tunnel, reinforced concrete tunnel that goes down vertically from the pump house and then out into the pond about where the arrow is. So that's your intake location of the water.

As we were in construction in the late

1970s, we found out that the pre-consolidation estimates for settlement of the pump house turned out to be much greater than we were anticipating at that point in time.

We discovered that during construction. So we accelerated the amount of settlement by filling the basin of the pump house as it was being constructed with water to preload that area. So we obtained a maximum settlement of almost 12 to 13 inches, but it was very uniform.

So after we achieved all of the settlement that we could recognize from this problem, we then continued with construction and built the pump house on up to finished grade and finished elevation. All of the piping connections were not connected until after all of the settlement had been achieved, I'll say, and we had understood what the problem was and recognized now that we had probably obtained all settlement that would occur.

We have a commitment in our FSAR to monitor the settlement of the pump house and intake structure twice a year, which we've been doing for the last 20-plus years, I guess, and I actually have a plot showing that if you'd like to see it. But basically it's a straight line plot. It hasn't

changed to any significance, less plus or minus a quarter of an inch over the last 20 years, and that appears to be a more seasonal fluctuation than anything unusual happening.

CHAIRMAN LEITCH: Okay. I think the last data we had and the information we had was like 2000, and it just seemed a couple of years old. I was just wondering if the settlement was continuing, but I guess what you're saying is, if I hear you, is after that initial settlement and it has been basically table since the initial construction.

MR. WHORTON: Basically stable since that point in time over the past 20-plus years.

CHAIRMAN LEITCH: And there has been no problem maintaining the joint, shall we say between the pump house structure and the pipes that are going into the plant?

MR. WHORTON: No, sir. We put in some --

CHAIRMAN LEITCH: As an expansion joint?

MR. WHORTON: We put in some flexible Dresser couplings in at those joints, and we are also actually monitoring the intake line for settlement as part of this program that we have for settlement monitoring to make sure that nothing unusual was happening there.

MR. BONACA: Why are you monitoring all of the intakes Line A? Is there more than one line imagined?

MR. WHORTON: It would be very representative of the other line. There are two lines, but it would be representative.

We're also monitoring the electrical duct banks that come in underground into the structure, and that's a statistical measurement where you can see the gap and actually take a measurement.

MR. BONACA: So they're representative because they're adjacent or because --

MR. WHORTON: At the location of the pump house, they're basically adjacent, and we just continued the service order intake Line A all the way to the plant just to have some baseline of what would happen across the yard of the plant area.

MR. BONACA: But if you do have some settlement on Line 8, are you looking at the other lines?

MR. WHORTON: Yes, sir. If anything unusual would happen, then that would promote us to go forward to look at other lines.

CHAIRMAN LEITCH: Now, the service water pond is maintained at a constant level, more or less,

and the reservoir, the Monticello Reservoir is associated with the pump storage plant. So it fluctuates; is that correct?

MR. WHORTON: The Monticello Reservoir fluctuates approximately four and a half feet per day is the design fluctuation. It may or may not fluctuate on a daily basis like that.

The pond is basically stable. Its maximum height would be 425 elevation. It typically would not get less than 423. We actually have a make-up line between the two pump houses that can provide supplies should we ever recognize that the service water pond dam was being deficient in water level.

CHAIRMAN LEITCH: Do you have some kind of analysis that, say, one of those dams should rupture and drain the service water pond? Is that part of your licensing basis?

MR. WHORTON: The dams that are safety class Seismic Category I, safety class dams, has been analyzed for a maximum earthquakes, the safe shutdown earthquake and operating basis earthquake.

CHAIRMAN LEITCH: So all those dams that surround that service water pond are Seismic Class I structures?

MR. WHORTON: That's correct. That's

correct.

MR. LABORDE: And they're surrounded by the lake on all three dams. The dams are all .5 of the lake.

CHAIRMAN LEITCH: Okay. Good. Any other questions?

That was very helpful, by the way. I appreciate that because I was confused in the reading. I didn't have the picture of what was done on it. Thank you.

MR. BONACA: I just had some questions regarding here anyway, structure.

MR. WHORTON: Excuse me?

MR. BONACA: Regarding some groundwater penetration that should have had in different locations of the containment. Could you explain leakage or penetrations in the auxiliary building, for example? And you have concrete leaching in candle (phonetic) access gallery.

Now, you make a statement that groundwater is not addressed, but, I mean, my question, I guess is is it, you know, a one-time occasion that you had some leaching or water penetration or is it the normal process that you have to monitor and correct for?

MR. WHORTON: Okay. As part of our

evaluation for license renewal, we have not really done any chemical analysis until about three years ago of just groundwater, but because it was an issue for license renewal, we took some samples.

The wells that are in green here, there are five or six or so, were the existing wells that we had installed I'll say ten to 15 years ago around the plant site, and they were primarily installed to monitor any oral leakage into the environment from our aux. storage fuel oil tank, and so that was the purpose of the wells.

Once we got into license renewal since the wells existed, we took some samples, and that's the data that we presented as part of our application. We found out that our chlorides and our sulfides were very low, much below the threshold. The pH in each of those wells varied from about 4.8 to 5.2, and that's what was reported. Those values are less than the threshold of 5.5 on pH, which the GALL has determined to be an aggressive environment.

Our terminology in the application was it's mildly acidic, but we considered that because our pH or -- excuse me -- our chlorides and our sulfides were very low that we were basically nonaggressive.

Now, the staff in further discussions have

basically discussed with us that if you exceed any of the three thresholds then you should be considered as an aggressive environment, and so that's where we are.

The chemistry we have taken here, the three wells that we reported on our pH, those are the values that went into the application there. We've continued to take some data over the past couple of years, and most from the same wells, and the data stayed consistent.

However, as you saw on the previous slide where there were a bunch of wells that were in yellow, we put in 38 new wells in the last three months primarily to look at controlling our site groundwater issues.

We have in-leakage in a lot of the structures, and it has been a nuisance for operations, is one of the biggest issues. So we're now evaluating how we potentially can de-water the plant site to eliminate a lot of the in-leakage that we have in the plant.

These three wells here, two, six, and nine, were recently tested, and as you can see, as it turned out the pH was actually higher on those. The difference, I talked to the engineers who collected the samples, and basically they said that they went

through all of the code processes to make sure that they purged the well and got fresh in-flow of groundwater, and that was the samples that were taken.

So I'm not sure if the old wells maybe had some contamination that could have changed the pH possibly.

As another example, we have a hydro project with a major dam about 30 miles from Summer Station. The geology and the soil conditions are very similar, and it might be helpful to show you a slide here just in a minute. The pH that was taken from recent samples there approach seven, which is, again, fresh, clean water. So those are consistent at that point in time

In our Saluda hydro project, which is about 30 miles away, this hydro facility and the dam behind it were built in the 1925 to 1930 time frame. We are currently building a secondary back-up dam for another purpose under FERC guidelines for seismic concerns, but as you can see in the construction, in 1929 to 1930, the state of the pump house, and here is a picture taken just in the last year. So you have 70 year old concrete, and even more dramatically, here's from 1929 to 1930. These are the penstocks that have been imbedded, were imbedded in the original dam with

concrete placement in 1929 and 1930.

This is a picture that was taken about six months ago, and when I visited this project back in September, I was amazed at the quality of the concrete that had been imbedded for 73 years under very similar conditions of chemistry.

PARTICIPANT: With the soil, the backfill was up to here.

MR. SIEBER: You need to use the microphone.

MR. WHORTON: Okay. So we're saying the soil level was above all of this area. So we have here a case of a 70-year time frame.

MR. BONACA: Are you saying similar concrete composition?

MR. WHORTON: Well, I'll actually say the concrete from 1925 to 1930, the QC and the quality level were probably much less than the QC and the quality that is put in today.

Just one other interesting point here. Before the concrete was placed around the penstocks, this is the type of construction in 1930 that took place. When we did the excavation recently, they excavated all of the scaffolding, the barrels, all of the contaminants, grease, you name it was all still

left in place. So they just backfilled over it.

MR. SIEBER: You finally cleaned it up?

MR. WHORTON: And now we're cleaning it up. So those are pretty dramatic, the point being that, you know, we have actually a test case now in the very comparable conditions where the concrete appears to survive very well in an environment that we have at Summer Station.

MR. BONACA: So, I mean, for example, for the concrete leaching in the candle access (phonetic) gallery, I mean, you feel that it's a limited amount and is controllable?

MR. WHORTON: Yes, sir. I have participated in all of the maintenance rule, and this will be more primarily for IWE and IWL containment inspections, and we have gone down each outage for the last three outages to insure that the conditions have changed.

We started our baseline in 1996 when IWE and L first came about. In the year 2000, we did a very detailed, complete plant evaluation for both maintenance rule and for IWE&L. During that 2000 inspection, we documented and evaluated the amount of leaching that was inside the tendon access gallery (phonetic), and the biggest problem we had was that

the drains for the gallery for any normal seepage had been clogged by some of the leaching material. There was a fine mesh screen over the drains which were left in from construction. So we removed those mesh screens. We cleaned up all of the build-up of leaching so that we could document any changes.

And when I just went in the salvage, refuel 14, which was about I'd say six weeks ago, the area was still very dry and clean and no significant leaching appeared to be evident.

MR. BONACA: Thank you.

CHAIRMAN LEITCH: Okay. Well, thanks very much. We appreciate that presentation. You'll still be around, and we may have some further questions for you as the morning progresses. I appreciate it.

So we'll turn the meeting over to the staff now, P.T., for a presentation.

MR. KUO: Yes, sir. Dr. Auluck and Kimberly Corp will be making their presentation, and staff experts are in the audience ready to help.

MR. AULUCK: Good morning. My name is Raj Auluck. I'm the project manager for the safety review of the Summer license renewal application.

With me is Kimberly Corp. She has been helping me the last few months in putting the safety

evaluation out together and other issues, and she'll be making part of the presentation to us later on Section 4.

And Caudle Julian, who is the lead team leader from Region II, will be speaking later on in the presentation.

This is some more --

CHAIRMAN LEITCH: I had some questions about the inspections, and I'm just trying to know when I should introduce those. When are we going to have the inspections discussed?

MR. AULUCK: After Chapter 2 I will go over all of that.

CHAIRMAN LEITCH: Okay. Thank you.

MR. AULUCK: And all the slides are included in the handout.

I was just mentioning that VC Summer is the fourth man that has implemented the GALL process, and all of these three applications last, they came together within a short period of each other. So essentially there was no lessons learned from one from the others.

So they each followed the FALL process through, you know, what they understood.

CHAIRMAN LEITCH: And how many REIs were

there in this case?

MR. AULUCK: In this case we had 280 REIs, and if you look over it all from a few years back, they have ranged from low 200s to higher number earlier, but now there seems to be ranging from low two to low three, and this one was 280, and then we go with Summer, you know, what kind of REIs were there. I think I just briefly looked over the next one, which also follows GALL process. It's 268 or so. So it's in the same ballpark.

My thinking is more like once we go to the new process where we go to the site and look at the, you know, application as there is a back-up information, that should cut down. I mean that's my opinion.

CHAIRMAN LEITCH: Didn't you get to the site at summer then? I thought you were in the new process now.

MR. AULUCK: No, this is the GALL process, and we had audits for specific purposes, like only thing different in this process was the GALL audit, AMP's audit, aging management program's office. Besides that it was all reviewed. Technical information was reviewed and supported by our contractor staff.

CHAIRMAN LEITCH: So you're now in the new process though of ones that are in the pipeline now? You're --

MR. AULUCK: I think there's one more.

CHAIRMAN LEITCH: There's one more?

MR. AULUCK: Which is following the GALL process as it exists now. I think starting with fouling they will start the new review process, which they're going through the many more cycles.

CHAIRMAN LEITCH: Okay. Now, there were a number of the ISGs incorporated in this process, were there not?

MR. AULUCK: They addressed all of those which had been finalized and, you know, positions. And this application, the review was also supported by the contractors from Brookhaven National Lab and Argonne National Lab, and they are available on the -- this line is available. If there's a need for them to, you know -- and they will assist the staff in responding to your questions.

Most of their support was in Chapter 3 and Chapter 4.

CHAIRMAN LEITCH: And that was primarily headquarters support, that is, it was not at the site, right?

MR. AULUCK: Right. Basically we was contracted out for certain parts of aging management programs and reviews to Argonne and Brookhaven National Labs, but we have the lead technical people behind us from the staff right here who are fully knowledgeable to respond to any of the questions.

CHAIRMAN LEITCH: Okay. Thanks, Raj.

MR. AULUCK: Next slide, yeah.

As the applicant has stated, the application was submitted on August 6th, 2002. It's a Westinghouse three-loop plant located in the town of Jenkinsville. That's about 25, 30 miles north of the City Columbia. Its current output is 966 megawatts electrical.

The current license expires on August 6th, 2022, and they are requesting for a 20-year extension to August 6th, 2042.

I'll just briefly go over what the NRC review process is used in this application. It concluded, of course, review methodology and deserves other scoping and screening of plant systems, structures, and components as described in the license renewal application, and for documentation available at the site.

Review included audits and inspections

conducted at the site, and as a result of our review, there were no knew structures added to the scope of license renewal. However, there are some components that were added, and we'll go over that in the next couple of slides.

And as a desert of staff review, three new aging programs were also added, and they were all in the electrical area and will be briefly mentioned later on when we make presentation on those programs.

The next slide just gives you the dates of the various audits and inspections conducted at the site. At the bottom you see the third inspection, which we call it an option inspection, and for many plants' earlier applications, we have not done that.

In this case, as earlier you raised the question on commitments, and the focus of this inspection was to look at that because, you know, whenever we were at the site, of course, questions were raised. How are you going to implement it? How are you going to crack it?

And we were told, hey, it will be part of -- it will, you know, fold it into the existing program and will be tracked. And so had a discussion with Region II. Caudle and myself would go and spend two days to look at their tracking system, and that's

what we did on November 16th and 17th, a few weeks back.

CHAIRMAN LEITCH: So that report has not yet been generated.

MR. AULUCK: That report has not been.

CHAIRMAN LEITCH: Okay.

MR. AULUCK: Yeah. Our next several slides identify different areas of review covered under different sections of Chapter 2 of SER. And Chapter two of the LRA provides the listing of all structures, systems, components included in the scope of license renewal. There was nothing unusual, unique about that review. So I was taken to go highlight some of the things we found which were not included and hopefully why they were not included.

As you can see from the REIs, many of the REIs were in the scoping scheme section work, in Section 2.3, which is scoping scheme of mechanical system and competence. I think in Chapter 2 there were about 18 or 20 percent of the whole REIs were in Chapter 2, and many of thee REIs were related to clarification of statements in the application, and many were also related to identification of commodity groups under which the applicant has been included.

As an example, I have a few examples here.

In the control room ventilation system, system dampers and filter housings are grouped together with duct work, fan and plenum housing. Grout is grouped under equipment packs. In the competent cooling water system, venturies (phonetic) are listed as orifices, and the structure area, refueling water storage tank, and the reactor makeup water storage tank are both in scope, but they're listed in the mechanical systems area.

So you see many of these were fully and bona fide REIs, but that information was already included. So hopefully the new process, once we go to the site, we shouldn't see those types of REIs.

CHAIRMAN LEITCH: So if I understand correctly, this is more of a bookkeeping issue than a matter of not including the information.

MR. AULUCK: Not including. But in that case of fire protection, we did find that there was a few things which were not included, and as you know, we always have questions in the fire protection area, and in this application the applicant uses a nomenclature QR. It's called quality related red flags. They had marked up all of their drawings with QR boundaries, and that is everything outside the QR boundary is --

MR. SHACK: It's one acronym that's not in your list in the SER.

MR. AULUCK: Ut-oh. Sorry.

(Laughter.)

MR. BONACA: One of the inspection reports reported that the tables included a number of systems which do not exist at the plant.

MR. AULUCK: Correct, and I think although we talk about that, yes, a quick answer is that Gilbert, Burns & Roe -- Gilbert -- the architect engineer had designed a plant and was the construction manager. They, when they prepared all their drawings, they used their whatever systems they had in house. They included all nomenclature of potential systems and basic definitions.

And when they finally ended up, some of the plant did not use all of them. So nobody took the time or effort to go take those, the nomenclature and things out. And when we went for our first inspection and we were going to look at certain -- we picked up certain structures and systems and then followed, hey, they don't exist.

So you know, at the time it looked strange, but I think when we met with applicant and --

MR. BONACA: Yeah.

MR. AULUCK: So it didn't impact any operation or view of the plant, but it does, you know -- we say there is something listed in FSAR, and the application doesn't exist.

Coming back to the fire protection, so the cure boundaries and according to the applicant the thought was that's everything inside of this QR, is in compliance with 3048. But our review indicated that these QR boundary flags on the drawings did not capture, completely capture all of the components and systems which needed further compliance with 5048.

So there were several back-and-forth meetings and REIs, and as a result, they added several components, including a fire service, jockey pump and associated piping, whole stations in several buildings, valve manifolds. They were added.

So here we can see that it is basically a difference in interpretation on what should be included.

MR. SHACK: This one seems inconsistent. I think jockey pump is one of those phrases --

MR. AULUCK: Jockey pump is mine.

MR. SHACK: You know, it always comes up.

MR. AULUCK: I agree, but many of these host stations is probably not as common, and you know,

so that was something once we've talked to them that we've said, yes, they should be included.

CHAIRMAN LEITCH: Is there an ISG issued or being planned on this topic?

MR. AULUCK: I think it has been put on hold, and I think they're going to discuss some more with the industry. I think maybe P.T. or Sam can.

MR. KUO: Yes, Dr. Leitch. This was an ISG before, but we had several meetings with industry, and recently, as recent as probably a couple of months ago, we had another meeting with industry, and both sides decided it will be -- for the moment it will be better to give review on a plant specific basis. So the ISG is begin put on hold.

CHAIRMAN LEITCH: I see. I agree with DR. Shack. It does seem to be a problem that continues to come up as though there's some lack of clarity in this particular area.

MR. KUO: Right, and when time is ripe, we will put an ISG through again.

CHAIRMAN LEITCH: Okay. Thank you.

MR. AULUCK: In the fire protection area, our review is pretty thorough, and we did find one thing which was missed out completely. It's a sprinkler system in the diesel generator building and

the diesel fire pump room and (unintelligible), and they were employed. So I think that is the only thing, I think.

And those are the kind of highlights of our scoping and screening. If there are no questions on this area, I would like to ask Caudle to come and talk about license renewal inspection program and documentation

CHAIRMAN LEITCH: When you look at the scoping and you find certain omissions in the areas that you look at, does it give you cause for concern that perhaps there are other areas where maybe your review has not been as thorough?

In other words, did this cause you to call into question the thoroughness of the licensee scoping process or did you think these were shall we say legitimate omissions or misunderstandings?

MR. AULUCK: On the fire protection, competence-wise, yeah, it was not a misunderstanding. It's just they are there in compliance, and that's where there is a disagreement of where the boundary should be. So that's, you know, a valid question and valid REI.

But if there were many more misses, I would have said that, but I think one area sprinkler

system in one building, I think it's --

CHAIRMAN LEITCH: Okay.

MR. AULUCK: No, I wouldn't want to be concerned. Especially we had 280 REIs and more than 50 or so in the scoping scheming and one which is found.

CHAIRMAN LEITCH: We are about due for a break. Would this be a good time to take it?

MR. AULUCK: Yes, I think that's what the schedule calls for.

CHAIRMAN LEITCH: Okay. Let's take a break until 9:40 then. We're in recess.

(Whereupon, the foregoing matter went off the record at 9:28 a.m. and went back on the record at 9:41 a.m.)

CHAIRMAN LEITCH: Okay. Come back into session, please, and we'll resume with a discussion of the license renewal inspections.

MR. JULIAN: Thank you.

My name is Caudle Julian from NRC Region II, and I was a team leader on the E.C. Summer license renewal inspections.

The slides that we have up, the first ones you've probably seen before. They're a little bit generic. So we'll go quickly through them.

We do a scoping and screening inspection and an aging management program inspection and an optional third inspection if needed, and we were looking at the commitment tracking system in the third inspection, and we'll cover that in just a moment.

We have a manual Chapter 2516 and the standard inspection procedure 71002. We put together a site specific inspection plan for each applicant, and we schedule our inspections to support the NRR review.

We have a consistent team of five inspectors in Region II, and we are again very fortunate in getting support from Louis Reyes, the Regional Administrator, to help us continue with the continuity you have, the same people.

And when members leave our team, we have to have a replacement training program for them.

Next slide.

CHAIRMAN LEITCH: Although we refer to the fact that a third inspection was necessary here, should that lead us to believe that the licensee was not quite as far along with some of the activities?

MR. JULIAN: No.

CHAIRMAN LEITCH: How would be interpret that?

MR. JULIAN: Let me address that in the third slide.

CHAIRMAN LEITCH: Okay.

MR. JULIAN: I'm not sure if I can. Keep them in order for me.

The scoping and screening inspection, the objective was to confirm that the applicant has included all appropriate systems, structures and components in the scope of license renewal. As required by the rule, it was one week in length, the V.C. Summer, and you see the dates, and there was very little outcome, very little negative outcome from the Summer scoping and screening inspection.

We concluded that the scoping and screening process was successful, and we again had very few negative findings from that inspection. It was pretty much clean. The one issue that you mentioned -- this would be a place to address it -- about the systems that don't exist, that was a unique condition which we had never seen before. It evidently began from an old procedure that existed in engineering that had about 25 names of systems that could possibly be included at other Westinghouse plants, but were not design features at Summer.

And we questioned why in the world does

such a document still exist at the V.C. Summer site, and we really didn't get a very clear explanation, but the plant management is well aware of it and, I'm sure, will correct it.

We pointed out to the applicant that that information, although it's not safety related, could cause confusion and cause one to conclude that there's errors in the application, and so Raj worked with me, and we sent an REI back, and V.C. Summer properly corrected that with an REI.

CHAIRMAN LEITCH: I noticed that your inspection report indicated that an RHR, SI, and RW, that there had been construction strainers that were removed and, therefore, were not in the scope, but when you look a little deeper, you found that it was really just the strainer bodies --

MR. JULIAN: That is correct.

CHAIRMAN LEITCH: -- in mean the strainer internals that were removed and the bodies were still in place, and the bodies were then added to the scope; is that correct?

MR. JULIAN: Yes, they were brought into the scope. The V.C. Summer folks, when we discussed that, recognized that our inspector was correct in that assessment, and they quickly brought it into

scope.

CHAIRMAN LEITCH: I was wondering about the generic implications of that. So I think that procedure may be common at a number of plants.

MR. JULIAN: It's something that certainly every time we find some little anomaly like this -- and I call it a little anomaly -- we do take that as a lesson learned, and we're looking for that the next time we go down the road to the next plant. That's a positive feature of having continuity of the inspection team, you know, is that they learn to look for things that they've seen in the past.

I don't know if the --

CHAIRMAN LEITCH: But is the inspection team just Region II based? In other words, would a plant in another region get the benefit of -- I'm not --

MR. JULIAN: Probably not, probably not. We don't have a very good, effective way of cross-pollinating, so to speak, from region to region, except with visiting inspectors. For example, I went out to the Quad Cities in Dresden inspections and joined them out there since that was their first one in Region III and did my best to inject everything that I knew, you know. That might be a good idea for

consideration.

In the next inspection, the aging management inspection, the objective is to confirm that the existing aging management program --

CHAIRMAN LEITCH: Just before you move on --

MR. JULIAN: Okay.

CHAIRMAN LEITCH: -- I haven't been to Summer, but I mean, this groundwater issue that we heard about earlier, what's your impression of the housekeeping and the material condition at the plant as a result of this groundwater leakage? Is it impacting equipment or is it just an appearance situation?

Could you comment on that?

MR. JULIAN: Sure. It does not appear to be negatively affecting the equipment. We looked specifically for that, looking for rusted supports and things that attach to the floor, and it appeared to us that they're doing a good job with keeping up with it.

Summer to me looks better now than it did ten, 12 years ago when I was over there, and I think they're making even more concerted effort to keep the groundwater intrusion problem down, and to take care of the equipment that gets affected by it.

The problem has been with Summer ever since it existed. It is worse than other plants that I've seen, and I don't know why, except that the plant is deep. It's very deep in the ground, and it's sitting right next to the lake, and evidently the water sealing on the outside of the plant must not have been as good as could be at other places, and so they have a continual groundwater intrusion problem in the lower levels of the auxiliary building, but they're continually fighting it and are doing a good job it looks to me like.

MR. BARTON: Are there any cables that run underneath the floor that could be subjected to this water, could be laying in the water?

MR. JULIAN: No, I don't think --

MR. BARTON: In conduits or anything?

MR. JULIAN: I don't think there are.

MR. BARTON: No?

MR. JULIAN: I don't think there are any imbedded, to my knowledge. Maybe Summer could correct me if I'm wrong, but I don't know of any.

MR. BARTON: Are there any areas of cable conduit that run underneath your floor that would be laying in this groundwater?

MR. CRUMBO: We have not found any.

This is Stan Crumbo, electrical engineer.

We have not found any, and do no suspect that there are any.

MR. JULIAN: Yeah, we're talking in the very lowest levels of the auxiliary building, the main area of --

MR. BARTON: Well, I know a plant in the low levels of the turbine building that has water underneath the floor and there's conduit and cable that runs in there. So that's why I asked the question.

MR. JULIAN: Yeah, I don't think they have any at summer, but their latest effort is that you've seen all of these wells that they drilled around this. It's going to be on the idea of building a de-watering system like a ship, continually have the bilge pumps running, you know and pump the water out, and it should work, and it should be effective and very helpful.

MR. SIEBER: In turn, that could give rise to settlement.

MR. JULIAN: True.

MR. SIEBER: You know, you get rid of all the water in the plant, it goes like Brigadoon.

MR. JULIAN: Well, back onto the aging

management program inspections, it was two weeks in length, conducted in August 4 through 8th and August 18 through 22nd, and there was really no negative findings of significance of that inspection.

We thought that the material condition of the plant was being adequately maintained and has improved over time. As I said, the documentation was of good quality.

We noted that there was a need to load the future license renewal tasks into the established site task tracking system. That's my terminology. They have different terminologies for it, but as most plants do, they have the official system for tracking items that need correction, the deficiencies they find, and also put in their licensing commitments that they're going to do down the road.

V.C. Summer had not done that yet -- move to the next slide if you would -- so we chose to go back for a third inspection, and it was very brief. Raj and I did it together, and to look at the effort that they had done in between time, and we noted that the applicant had loaded the future tasks into established site task tracking system and that the few revisions that we pointed out in her report that needed to be made to the basis documents had been

made, and we sampled those and some of them -- many changes had been made to the basis document since we had been there last, and they had been officially issued now and were getting ready to be put into the design basis document as they describe.

PARTICIPANT: Are in the system.

MR. JULIAN: Right, and we thought we couldn't find any deficiencies there.

You asked a question earlier about the third inspection. Is that negative inflection; is that a bad thing? In my opinion, it's not necessarily. The plants that I've gone to for license renewal I've seen different applicants do different things.

We've seen plants like Florida Power & Light establish an official system day by day by day throughout their process, and when they got done, they had everything loaded in, you know, to their system, and it was there and established and not a problem.

We've seen people who have established their own corrective action system, their own tracking system, rather, for items that they're working in license renewal, and that's probably the source of the comments you made earlier from our inspection report where we said they had not yet established a system.

They have not established their own separate system that we could detect to track work items, things to do, et cetera.

Some people do that. They have their own separate system, and then at the end of the process, they load it all into the official system.

V.C. Summer chose to wait until the SER was out, and they had more focused on what would be the commitments to NRR, and then they went back and loaded all of those into their system, and Raj and I looked at the efforts that they had done and thought that they were complete. We couldn't find any holes in them.

This is a list of the CERs that they have loaded in. I have forgotten the exact number, but it was up about 50 or so, and each item corresponded to an item in the SER commitment to NRR and/or in our inspection report.

So we thought they had done a good job. We were very pleased with the follow-up inspection that we did. I don't necessarily see that as a negative.

CHAIRMAN LEITCH: Okay. There was a couple of other items that in your original inspection report you said would be the subject of future

inspection. One of those was also new aging management programs that you said were not yet developed and would be the subject of a future inspection.

Was that done in this third inspection, or is that yet future inspections?

MR. JULIAN: That is yet to be done as we discussed before. The NRC has a future piece of work to do at each one of these reviewed licenses, and that's what I meant by that language, is that the NRC has established a procedure which we're keeping up with, 71003, and we're going to have a punch list of things to go follow up on at the time that the renewed license kicks into the extra 20 years, and we have not yet decided whether we're going to have an established team from the region. Are we going to dole it out to the resident inspectors to do?

We haven't taken the time to address who's going to do it, but we are keeping a list of the work so that we know what needs to be done.

CHAIRMAN LEITCH: Okay. There was another comment in the inspection report that said the steam generator inspections are the subject of ongoing inspections by the NRC. Is that just along --

MR. JULIAN: That's just the normal ROP

process.

CHAIRMAN LEITCH: Okay.

MR. JULIAN: NRC inspections of their efforts to look at steam generators every outage is just an ongoing thing that we do. We try not to duplicate effort and waste resources, and our inspector who is looking at that, Kim Van Dorn, particularly put that language in, so that the public know who reads the report that NRC is specifically every outage looking over the shoulder of the applicants who are doing steam generator inspections as you do for in-service inspection. That's another area where that's in a routine program.

CHAIRMAN LEITCH: So I ought not to infer anything special by that phraseology.

MR. JULIAN: No, nothing special for Summer. In fact, their steam generators are in very good shape.

CHAIRMAN LEITCH: Okay. Thank you.

MR. JULIAN: And the last thing that you asked us to address in the past is the current ROP performance, and V.C. Summer has a very good performance record as you can see. This is off our Web site and in the ROP area, and all of the performance indicators are green, and there have been

no NRC inspection findings of any significance in the last two years.

So we think that V.C. Summer is a very good performer as far as operations go.

Are there any other questions?

CHAIRMAN LEITCH: That just reflects PIs that are any significant inspection findings?

MR. JULIAN: No, they're not.

CHAIRMAN LEITCH: Not greater than green?

MR. JULIAN: Not greater than green, right.

CHAIRMAN LEITCH: Okay. In Attachment 2 to the inspection report, it says a list of programs selected for inspection. It looks like that was virtually all of them; is that correct?

MR. JULIAN: Right.

CHAIRMAN LEITCH: I couldn't find any that were not on that list. So you really looked at them all. It's not just an audit thing. You did, indeed look at them all.

MR. JULIAN: Yeah. We went into this program not knowing what to expect, and so our inspection procedure says we will select a sample, but as long as the number of aging management programs remains as it is, we are able to divvy them up amongst

the inspectors and look at them all, and we think that's a good thing to do since we have the resources to do that.

MR. SHACK: Is that a regional thing? I mean that's just --

MR. JULIAN: Yes.

MR. SHACK: -- Region II has made the commitment to provide enough resources to do that.

MR. JULIAN: Right, and so far I believe we've done that consistently, I believe, in the other regions. I know that we did the Quad Dresden inspection. I think we handled them all in Region III.

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

I think the one that I remember is Fort Calhoun. I don't think we finished all of the programs at Fort Calhoun. Part of the reason we have was that that was the first GALL plan. So we did not expect -- I guess like Caudle was saying, okay, we didn't know how difficult the job was.

So in that case, we were not able to do all of the programs, but I think we left like two or three programs out.

MR. JULIAN: Fort Calhoun comes to mind

now that that may be a sample process.

MR. LEE: I guess the inspection procedure asked for a sample, not a program, but as long as the people are there on site at the time they do, you know, as much as they can.

MR. SHACK: Right.

CHAIRMAN LEITCH: I noticed that the inspection report referred to non-EQ instrument cables, and apparently there's two different approaches that can be taken there. One depends upon failed surveillance test data, I guess, and I'm not really clear just what the two approaches are and when you use one or when you use the other. Could you discuss that?

MR. JULIAN: The GALL language in this area on non-EQ instrumentation for nuclear instrumentation and radiation monitors, high range radiation monitors, high range radiation monitors is concerned about the aging over time of that cables and a change in the IR characteristics, you know, the resistance of the insulation.

The GALL specifies that it would be a good thing to do to utilize, to look at the results of normal surveillance that are performed routinely as required by technical specifications.

Yes, loop calibrations. It implies that you should look at the trend of those things, but then it is confusing in the spot where it says no trending is required. We had quite a dispute with some applicants over that, and of course, if you don't track and trend the data, you're wasting your time.

But there are things, some instruments, where they do a continual loop calibration, where they will check the cable and the detector together, and those will fit in with the GALL program.

And then there are instruments in which they disconnect the cable and do a calibration on the drawer. In those instances, we've written an ISG that says that you can use other methods if you want to to do a special test of some sort, an insulation check on that cable, and that's the alternate program.

And V.C. Summer wanted the flexibility, as I understand it. So they wrote both of those programs in and are uncertain yet, I think, about how things are going to divide between those two.

PARTICIPANT: And both programs apply toward --

MR. PAGLIA: All of the cables that are in scope are not included in the loop count. So we have to do the alternate method.

CHAIRMAN LEITCH: I see.

MR. PAGLIA: We know we have a defined scope for those.

MR. JULIAN: It comes from the problem that the GALL described program is not readily adaptable to people who disconnect the cables and don't do a loop cal., but just disconnect the cables and work on the instrumentation package itself.

That's a very confusing area which we need to clarify one of these days.

CHAIRMAN LEITCH: I guess you also talked about, and maybe we'll get into some of this later, varied tanks and piping. I guess it wasn't clear to me. Are we talking about external only?

This was on page 7 of their inspection report. Did that just apply to externally?

MR. JULIAN: I believe that's external. The reason that some of the -- Summer tried very hard to follow the GALL program, and in fact, using some of the language that's specified in GALL when it's not really applicable, and you see some places where we talk about buried tanks and piping, and then the first thing we say is there is none of this.

And so it's a little bit confusing when they force fit the GALL language into the names of

their inspection programs.

CHAIRMAN LEITCH: Okay.

MR. BARTON: In Section 211 of level scoping, there's a subsection there that's entitled non-safety related mechanical systems, and there's a statement in there that the applicant has not completed review of high energy piping, insulation, seismic code break, and leaks, et cetera, et cetera, at the time of the LRA.

Has that subsequently been submitted and reviewed and accepted by the staff?

MR. JULIAN: Yes, it has.

MR. BARTON: Okay.

MR. JULIAN: That's the concern of non-safety related piping in the area that we discussed before on --

MR. BARTON: Okay.

MR. JULIAN: -- safety related, and Summer was one who had to go back and address that issue after the fact as opposed to it being in the application.

MR. PAGLIA: That was the supplement that we submitted in September following the August application.

MR. BARTON: Thank you.

MR. JULIAN: Well, if there's no further questions, I'll turn it back to Raj.

CHAIRMAN LEITCH: Well, I had one, and I'm a little confused. Were you speaking for the audit report as well sa the --

MR. JULIAN: The GALL audit?

CHAIRMAN LEITCH: Yeah.

MR. JULIAN: No.

CHAIRMAN LEITCH: Okay. I'll come to that later.

MR. JULIAN: That's another new feature that we've added this time to Summer, Ginna and Robinson, where there was a step forward towards their new process, and they put together a special audit team of NRR people who went down and looked at whether or not the applicant's statement that their program is consistent with GALL is absolutely true, and Raj can address that.

CHAIRMAN LEITCH: Okay. I'll defer my questions on that until that time.

Thanks, Caudle.

Anything else for Caudle?

MR. JULIAN: I want to thank you for reading our inspection report.

(Laughter.)

MR. JULIAN: I asked the question of an applicant recently had they read our inspection report, and I got a blank stare.

MR. KUO: Dr. Leitch, maybe I just try to clarify your question. I heard that you asked the question a couple of times already. Between the previous review approach and the new approach, we have a transition and that starts with Robinson. Robinson, Ginna, Summer and Dresden, Quad City, these four plants are subject to this audit that Raj was talking about.

That audit is basic to go to the site and verify the consistency with GALL, nothing else, just that.

CHAIRMAN LEITCH: So when the licensee says, "This program is consistent with GALL," to verify that that's, indeed --

MR. KUO: That is, indeed, true. And the new process, when the audit team goes on site, starting from Farley in '02 and Kirk, they are going to actually look more than just consistent with GALL. They're also going to look at, say, those programs that are consistent with some previously approved staff positions, and also they are preparing the SER's input.

So the audit teams assumed much more responsibility than the audit team that goes out to Summer. So we will schedule a briefing for the committee some time later to brief you on the new process.

CHAIRMAN LEITCH: Okay. So that will begin with Farley?

MR. KUO: Yes, that has begun with Farley.

CHAIRMAN LEITCH: Okay. We just haven't seen that. Right, yeah. Okay. So that's not so much an additional activity. It's really a relocation of the activity from the program home office to the site where you can --

MR. KUO: Correct.

CHAIRMAN LEITCH: -- perhaps get more expeditious clarification.

MR. KUO: Exactly

CHAIRMAN LEITCH: And perhaps eliminate some of the REIs and paper work back and forth.

MR. KUO: That's the idea.

CHAIRMAN LEITCH: Okay. Good. Thanks, P.T. I appreciate that clarification.

I was a little confused with that intermediate step on these four plants that we're looking at right now. I was thinking that we're

already in the --

MR. KUO: No, not yet because we didn't have time to perform the whole --

CHAIRMAN LEITCH: I understand.

MR. AULUCK: We started on aging management review of the application. The GALL device, the system structures into six groups, again, for aging management review and aging management programs. We will highlight certain areas of staff's review of the application which is unique to this site, and the staff is available to answer any questions in any of the areas.

There are 45 aging management programs and someone to manage the aging of competence and structures included in the scope of license renewal. These include existing as well as new programs. Of these, 34 are addressed in the GALL report and the rest, 11, are non-GALL programs.

Of these 45, again, nine are addressed in the first part of Chapter 3 under the common aging management programs, and the definition we have used is that they're applicable to at least two systems, and that's what I am sort of describing the system sections of the SER.

As I mentioned earlier, as a result of our

review, there were three new aging management programs that were added, and they were all in the electrical area, and we were just talking about those two, and the first one is wrap for electrical cables used in the instrumentation circuit not subject to 5049 requirements.

And one of the reasons this was based on our REI, initially the applicant had stated that the visual inspection of these cables is a better means to detect any degradation of the insulation, but the staff did not agree, and after further discussions, they agreed to add this program for those cables where you can use loop calculations to detect the degradation, and it's consistent with GALL E-11 and E-2.

And as you just mentioned earlier, for those cables which are not in this loop calibration program, they're going to initiate a new program. It's called alternate E-2, and they provided us in response to an REI, provided the ten attributes similar to the attributes in the GALL, and then staff has reviewed that program and found it to be acceptable, and the details have not been developed as yet, but some of the details are like the cables that are being tested every ten years and testing may

include insulation resistance tests and other tests for the cable installation.

CHAIRMAN LEITCH: That may be a possible future improvement to GALL, would it not? In other words, I don't think this is necessarily a Summer unique issue.

MR. AULUCK: Right now I think there is ISG in the works or there are discussions going on between the industry and the staff, and once that is finalized, it will be, you know, put it into the GALL, yes.

CHAIRMAN LEITCH: Okay. Thank you.

MR. AULUCK: The third one is also in this area, is called for inaccessible medium voltage cables not subject to 5549 requirements. In the application, the applicant identified that damage leading to electrical failure is caused by moisture intrusion and water treats.

There the aging effects mechanism for inaccessible medium voltage cables, but in the application, no program was proposed, and the reason given was that the history has not shown any such instance of cable degradation at Summer. So that's why I think they didn't propose it.

But based on our staff REIs and further

discussion, the staff agreed to add this program. They responded to the ten attributes consistent with GALL, Program 11(e)(3), and you know, staff has reviewed that and found it to be acceptable.

CHAIRMAN LEITCH: This is the treeing issue?

MR. BARTON: Water trees, yeah.

MR. AULUCK: Exactly.

CHAIRMAN LEITCH: Do we know what to do to detect these problems? It's an aging management program, but it commits to follow the future developmental work in this area.

In other words, I don't know that we have a good, nondestructive test for detecting this kind of a problem, do we?

MR. AULUCK: I do not know. Maybe we have Doug who can substantiate on this program.

MR. NGUYEN: My name is Duc Nguyen for electrical, and I'm a reviewer for electrical.

And you're right. Right now we don't have a very good test because mode of pipe as you mentioned may be destructive. So we are leaving the applicant to implement this test. In the future maybe something come up better.

As long as they commit to the test like we

indicate in the GALL, proven, energy proven test, and we leave it there, and as you say probably right now the test that we have is probably not very good. Most of them are destructive tests.

And this is consistent also with our acceptable (phonetic).

CHAIRMAN LEITCH: Okay. Thank you.

MR. AULUCK: Moving further we'll talk about the aging management program audit we conducted at the site. We conducted on July 16th and 17th of this year. The team included five staff members and two contractors. The reason for such a large team was that this was the first time contractors were with us. So a little bit more of training and so, you know, they can use similar process in thinking what we're looking in the future inspections.

We look at all 34 programs. We compared the attributes as described in the program. This is documents which are called the technical reports at the site; compared them with GALL report or what all the team found that attributes were consistent.

However, at many places some clarifications and additions were needed for consistency, and in the report we highlighted those when we left the site, and applicant agreed that they

will put those activities into their CERs, which is a condition evaluation report, and which will be part of their corrective action program, and so that activity also we inspected during our optional third inspection and showed that each of those activities which we had highlighted did an audit, was included in their corrective action program.

CHAIRMAN LEITCH: I had a couple of questions in that area as well. In Paragraph B-3.2 of that inspection report relating to thermal fatigue, it says that they'll revise the program to base the analysis on 60 years instead of the current 40 years at some time in the future, the way I understood it.

How do we know that's okay? Why can't it be done now? In other words, why is this a future thing, or has it now been done and closed in the November inspection?

MR. AULUCK: It has not been done as yet.

Ken Cheng.

MR. KUO: I have Dr. Ken Cheng answer the question.

DR. CHENG: In this matter of fatigue or Summer fatigue monitoring program area, the application itself has a Summer fatigue monitoring program in there, and they identify two enhancements

that need to be implemented. Those two enhancements are both in the area to take care of the environmental effects, two enhancements. From the application, identified two.

It's also said that some of fatigue management program is part of the TLAA. So we went also into the TLA part of their they call it basis document or the TR reports, technical reports.

In there it mentioned that each December staff from operating, they have many cycle counting first, and then by 1991 they had an automated cycle counting. But cycle counting, don't mix that with the on-line stress evaluation.

By 1995, the V.C. Summer program for cycle counting and CUF calculation program using WESTAMP has been initiated, and take a few years to develop that so that it fits V.C Summer specific configurations and conditions and transients.

By 2002, it was implemented, start operating, and beginning of 2003, V.C. Summer performed an annual review of the cycle monitoring program using WESTAMP and is summarized in January 7th, 2003 reports.

To summarize that, it give a good introduction of the, let's say, stress based

monitoring program. In monitoring cycle county (phonetic) at certified locations, it cover most of the locations that you need.

It also covers, five components at seven locations. Those seven locations corresponding to NUREG CR-6260, one to one, and they give a summary of what has been recorded and evaluated during that one-year period.

To fill out those reporting items, but not to give the items; there are only three items in a metal fatigue area which can potentially exceed the code allowable of 1.0 for usage factor. Those three locations are the charging nozzle, the alternate charging nozzle, and the surge line connection to the hot leg.

At the time when they summarize, it's base don part of the assumptions in the first few years before you have the monitoring system, then plus a projection based for the future.

AT the time the variation was done, charging or alternate charging has .46, .47, respectively for Unit 1 and Unit 2.

PARTICIPANT: CUF.

DR. CHENG: CUF. For surge line, .37. In other words, the conclusion was made that said based

on this training -- this is training. It's not a scientific evaluation -- based on the training, it's safe to say there's three components. It's the limiting condition, limiting locations will meet the EOL, end of life, CUF limits, but it will not meet the plant life extension or renew extended period of operation.

But that's okay because that's only the first cut. It's trending, pointing in the direction of what kind of order of magnitude you need to be improved. In that 2002 summary evaluation, it's also summarized seven additional future actions, which we also called enhancement.

So we have created a two-level enhancement. The application has one-level enhancement. It's to bring the design basis to the environmental effect. Two enhancements, and in the WESTAMP report, seven enhancements to bring the WESTAMP system tailor made for this assembly.

When these two are combined, we envision that this will be a very good tailor made system for the cycle fatigue monitoring of V.C. Summer. And the reason we cannot do it now is it's only a one-year training data. It's not enough to conclusively extrapolate. It's just a training.

Did I answer your question?

CHAIRMAN LEITCH: Yeah. That's a very complete answer to the question. Thank you.

MR. AULUCK: Any other questions?

CHAIRMAN LEITCH: Yeah, I had another question where the inspection report indicated that the steam generator inspection recall only included the tubes.

MR. AULUCK: Right. I think --

CHAIRMAN LEITCH: Not the shown internals. I was confused by that. Am I reading that correctly?

MR. AULUCK: Yeah, this is right. GALL only talks about those that are in tubes, and they have added something more. So this is a little more than the --

CHAIRMAN LEITCH: It's commendable that this licensee did that. I'm just a little surprised that GALL doesn't include the shell in internals. I think that there's some generic implications perhaps.

MR. ELLIOT: This is Barry Elliot.

CHAIRMAN LEITCH: Yeah, Barry.

MR. ELLIOT: The steam generator shell is included in the GALL report. It's one of the items that in the reactor coolant system that we have further review on, and the review is to determine

whether or not there's pitting and cracking associated with the shell welds, in particular, where the water level goes up and down.

If you remember, that was an Indian Point 2 problem, and we look at that for license renewal to see if the plant is susceptible to that type of aging effect. In this plant we did look at that, and it is not susceptible.

CHAIRMAN LEITCH: It is not?

MR. ELLIOT: It is not.

MR. LEE: This is Sam Lee again.

The GALL writes up the steam generator program, GALL has its specific steam generator program in it. It only addresses the tubes. However, the shell is addressed separately. It's not part of the program, part of the so-called steam generator program, kind of like Barry said. Okay?

Because you get the surface inspection, ASME Section 11, that also addresses the shell and also the staff is collecting from past experience. Sometimes being looked at separately. That's why when you see, you know, pop-out strips they start with just looking at the portion of the program, and then they talk about trips (phonetic).

MS. LUND: I'm Louise Lund. I'm the

Section Chief for the steam generator integrity in the Chemical Engineering Section, NRR.

And what Sam and Barry were saying is true. The program, the AMP, aging management program is the steam generator integrity AMP, and it covers the tubes. However, this is not the first plant that has, you know, gone kind of over and above in the steam generator integrity AMP and actually included more.

However, it really does have some overlap with the in-service inspection, you know, AMP. So, see, there's a little bit of overlap in those two programs.

So different plants have chosen to do it different ways. I think, you know, they're trying to be consistent with GALL. I mean, we don't look at that as being inconsistent with GALL. It's almost, you know, doing that and an enhancement.

CHAIRMAN LEITCH: Yeah, and could you comment about internals as well? Apparently there's also a question about some internals not being included in the steam generator AMP. Is that --

MR. AULUCK: Yeah, they call it anti-vibration bars and feedwater distributor.

MR. ELLIOT: We have a whole list of

components like jet impingement bars and vibration bars. They are reviewed, but they're not part of the tube inspection program, but they're reviewed as part of GALL, but as part of additional items that we consider to be reviewed.

MS. LUND: They're in the list in the aging management, the AMR section, the aging management review. You know, there's a whole list, as Barry said, in those components. So they don't get left out as far as the few goes.

MR. ELLIOT: What we did is the review plan has a whole bunch of reactor coolant components that require further evaluation. Steam generator internal type of components are one of them, and licensees have to address that as far as further evaluation, and we have to address it, too.

MS. LUND: And, you know, I think why the aging management program for the steam generator integrity is the way that it is, is because the specifics for it typically in the technical specifications are not in the ASME code. So that's why there's an aging management program and also an NEI 9706.

So the plant generally comes back and says, you know, "This is may aging management program,

is for doing a steam generator inspection for the tubing," okay, is in the technical specifications specified in the technical specifications, plant tech specs and also, you know, under the guidance that's in NEI 9706.

So that's why it's kind of more of a unique type of program.

CHAIRMAN LEITCH: Okay. Thank you.

So again, I guess my concern was not with Summer, but rather with other plants that perhaps didn't --

MR. ELLIOT: But, you know, we do look at all of t hem.

CHAIRMAN LEITCH: They are reviewed. Okay.

Okay. Thank you.

MR. AULUCK: Okay. Moving on, I think Slide 21 I think talks about different neutral sections of Chapter 3 of the SER. The first one is reactor system. You see the list. This provides the reactor coolant system Class 1 competence which are part of the reactor systems and thus subject to aging management reviews.

Just as a note, the steam generators as mentioned earlier were replaced in 1994. So,

therefore, at the end of extended period of operation, they'll have seen only 48 years of their life.

Our next slide talks about the Alloy 600 program, which we have talked earlier, but this is basically a commitment, this language here, which indicates that the applicant has committed to cooperative imaging requirements and recommendations into their program, and further, it will permit the staff to review the aging management programs for acceptability.

The next one talks about --

CHAIRMAN LEITCH: The SERs seem to indicate that the applicant did not use the Westinghouse WCAPS, the Westinghouse analysis, as many other applicants have done. I didn't know how to interpret that. Why did they not use the WCAPs?

MR. AULUCK: I think they have not used any of the WCAPS on a generic basis, and they have taken information on a plant specific basis, but I think maybe the applicant can respond to whether they decide to do that.

MR. PAGLIA: Yeah, what we chose not to do is to rely upon the SER that was written on the WCAPS that were taken all the way to completion, and then there were some WCAPS that were in draft and under

review.

We used the materials that were in the WCAP, the technical information about our plant, as a basis for the evaluation that we put forward. We just had it reviewed through the SER done on the application rather than just simply refer to SER on the WCAPS.

That's really the only difference. The material is still applicable.

CHAIRMAN LEITCH: So it's really kind of a bookkeeping, administrative kind of an issue, not a technical difference. Okay. Thank you.

MR. AULUCK: The next slide is you've got two new programs, and the commitments as, you know, are identified here permit the staff to review the acceptability against NRC requirements.

Moving further on, I think under Section 3.2, 3.3, and 3.4 and 5, there was nothing unique about the review. However, we have, you know, a specific area that you want to mention and talk about regarding aging management of in scope, inaccessible concrete. There was, you know, mention earlier on the chemical analysis of the water, and this was taken from the three wells, and the table shows the values of pH, chlorides, and sulfates. This was based on a

staff review, and there was an REI on it, and applicant responded with this information.

And as mentioned earlier, these samples were taken from 2001, and in the application it was classified as a nonaggressive but based on staff review we thought, you know, it should be considered as aggressive, and because of that specific provisions were added into the program, and these provisions are site procedures will be revised to include concrete surface examination, if soil is removed existing to any concrete surface at or below the groundwater elevation of 423.

Second, a chemical analysis of groundwater will be conducted on a five-year interval to coincide with the maintenance rules structures inspection program. This analysis will also include a water sample from the surface water pond.

Third, underwater divers' inspection of the service water intake structure will continue. These instructions will provide additional assurance of the integrating of the concrete structures exposed to the water conditions and since that operates with the new values of the recent combination wells.

CHAIRMAN LEITCH: So we consider this to be all of the above. In other words, if any of these,

it's not --

MR. AULUCK: It is not either/or.

CHAIRMAN LEITCH: It is not either/or.

MR. AULUCK: Right, right.

CHAIRMAN LEITCH: In other words, if any of these conditions --

MR. AULUCK: Yeah, there was sensitivity on these values and comparisons.

CHAIRMAN LEITCH: Because I would think, having such low chlorides and sulfates, the pH is lightly buffered and easily changed and, you know, I would think the pH might not be as significant when the chlorides and sulfates are that low, but at any rate, if any one of those falls below, falls outside of this one, it would be considered --

MR. AULUCK: Falling, yes.

CHAIRMAN LEITCH: Okay.

MR. AULUCK: Moving on, I think, at the last meeting, the ACRS had requested us to talk about one-time inspections, and so we are prepared to do that at this meeting, and as a background, the GALL report provides guidance to the ten attributes for a typical one-time inspection program. These inspections include mergers to verify the effectiveness of an aging management program and

confirm the absence of an aging effect.

Second, these inspections will address two aging issues. The first one is aging is not expected to occur, but there is insufficient data to completely rule out aging.

Second, an aging expect is expected to progress very slowly.

Next summer --

CHAIRMAN LEITCH: Raj, can I just say that, so that we understand where we're going here, this topic of one time inspection is not necessarily related to Summer. That's correct, isn't it?

I mean, what we --

MR. AULUCK: It was a general topic, but we had stated that we'll take a couple of examples from a Summer application, and we'll talk more in detail about those.

CHAIRMAN LEITCH: Right. In other words, we were concerned that this topic of one-time inspections seems to be continually coming up, and we asked the staff to give us a little more in-depth discussion on one time inspections and Raj is being responsive to that request in this next little piece.

MR. AULUCK: If you look at the application, there is in GALL, it says one-time

inspection, and you know, different applicants are treated differently. Some applicants have a program called one-time inspection, and some there is no program called one-time inspection.

They have nine programs as listed on the next slide, which use the attributes given for one-time inspection in the Gall report, and then those programs have their own attributes acceptable at the end and so on for each of those, and we will take example of two of these programs.

One is the underground tank inspection, and second is the heat exchanger inspections, and we'll talk a little bit more detail of these programs, and the first one we'll talk about is above ground tank inspection, and Carolyn Lauron from our staff will make the presentation.

MR. KUO: But to answer Dr. Leitch's question, this is an attempt to answer the questions about concerns about one-time inspections in general, but we use a summary of data in Summer to illustrate that.

MR. FORD: But this assembly, again, this is an action item that we come away, you know, from the last ACRS subcommittee meeting.

CHAIRMAN LEITCH: Right. Thank you.

MS. LAURON: Okay. My name is Carolyn Lauron. I'm from the Materials and Chemical Engineering Branch.

I reviewed in conjunction with the reviewers from Argonne National lab the above ground tank inspection program. I'll be presenting the staff's review of this new, one-time inspection, and the basis for concluding that it provides reasonable assurance that the in-scope tanks will be adequately managed so that the intended functions will be maintained for the period of extended operation.

As Raj went over, the GALL provides for the on-time inspection to verify that either (a) an aging effect is no expected to occur or there was insufficient data to completely rule it out and (b) an aging effect is expected to progress very slowly.

In the case of Summer's above-ground tanks, lots of material due to general corrosion is not expected to occur or, if it is occurring, the corrosion is expected to progress slowly because of the chemistry controls of the fluid stored within the tanks.

The fluid stored in these tanks are part of a closed treated water system with the addition of corrosion inhibitors.

In addition, by means of water chemistry guidelines delineated in the GALL report, the applicant is controlling the purity of the fluids and the entry of contaminants into the water system.

There are materials, handbooks, out that discuss general corrosion of structural carbon steel as a slow, generally uniform process. The average loss in thickness of carbon steel exposed to a rural atmospheric condition, which is applicable to Summer, is less that five mLs over 15 years.

And I believe if it's projected out, it's around 25 mLs.

With respect to galvanic corrosion, this aging effect is possible at the connection of carbon steel tanks to the stainless steel instrument tubing. Once again, based on handbooks, the rate of corrosion will vary directly with the increase or decrease of the area ratio of the more noble metal to the less noble metal when connected by the electrolyte.

In this case, the more noble metal is stainless steel. It is smaller area. It is connected to the electrolyte, which is the fluid in the tank, to the less noble metal, which is the carbon steel. Since the ratio of the more noble to the less noble is greater, you expect minimal corrosion of the anode,

which in this case is the carbon steel tank.

The summary of above-ground tank inspection relies on visual and volumetric inspections on a sampling of subject components to verify that degradation of the carbon steel and stainless steel tanks are not occurring. The inspection will examine the tanks for measurable changes in wall thickness and visible evidence of corrosion and cracking.

The inspection focuses on bounding components most susceptible to the aging due to time in service, severity of operating conditions, and lowest design margins. The inspections will include locations of the air and water interface, of the stainless steel RWST in one of the carbon steel tanks and some locations of the sodium hydroxide tank.

The inspections are performed by qualified personnel in accordance with the requirements of the ASME code and Appendix B. In addition, the program provides for additional inspections should corrective actions programs require additional information to characterize the aging effects.

The SAC (phonetic) concluded that the above-ground tank inspection is inseparable because it is a conservative program for verifying the internal surfaces are not experiencing the slow, generally

uniform, general corrosion and minimal galvanic corrosion.

The staff would like to also point out that in the GALL report there is an above ground tank inspection which addresses the external environment, which is more corrosive because the atmospheric conditions cannot be controlled. There is the possibility of salts or sulfates, the industrial fumes that could enter into the corrosion process.

In addition, there are provisions included in the program to preclude a negative impact to the function of the in-scope components, and there is industry experience of similar tanks which have been drained and inspected, resulting in little or no evidence of corrosion. I think the most recent one is Ginna that they had mentioned earlier in the committee, when they came before the committee.

Next slide.

With respect to Summer's carbon steel and stainless steel tanks, this slide shows you that the internal environment is managed by both this new, one-time inspection and the chemistry program. While the external environment is managed by two inspections, the inspection of mechanical components and the maintenance rules and structured programs. Those two

external programs have periodic frequencies.

CHAIRMAN LEITCH: When you say above ground tanks, are you referring to those tanks where you can see all around them like a cylindrical tank?

MS. LAURON: Yes.

CHAIRMAN LEITCH: But this acts in parallel to the ground and you can see all around it or are you talking about something like a condensate storage tank or a cooling water storage tank where you may be able to see the sides, but not the bottom as well?

MS. LAURON: Right. I believe the CSC is encased in concrete and sand, and you do have a commitment for a --

MR. DANTZLER: -- has got a concrete base and it's got a ring wall over the top of the concrete that extends. The ring wall extends about one foot below grade, and the tank sits on the top of the ring wall one foot above grade. There is sand inside that, the ring wall, and there are drains down at the two feet level. There are four little drains.

So water is not going to pool on the bottom, and besides, we have the inspection program to look at the deal on the foundations themselves.

So we expect maybe some general corrosion

that is slow, and 25 mLs at most in 60 years.

MS. LAURON: Next slide.

This summarizes the tanks, the above-ground tanks, at Summer, and you can see that there's a combination of programs for both the internal and external environments.

MR. AULUCK: Any questions?

MS. LAURON: Oh, sorry. Any questions?

(Laughter.)

MR. FORD: I think this question of one-time inspections came up at Ginna, and our problem primarily was the extent of the quantity to evaluation of the amount of degradation that might occur.

In other words, was there someone on the staff, a kind of qualified corrosion engineer, who went and looked at these structures and assessed what is the likelihood that you could get degradation between now and the one-time inspection and then beyond, and what would the consequence be if corrosion did occur outside that inspection period?

And what I've heard you address here was going down a list, ticking off whether this occurred -- was this covered under this particular program, et cetera, but there was little quantitative quantification of the amount of damage that might

occur and what would the consequence be, and that was essentially our concern that we brought up at Ginna, and I thought that we might be addressing during this presentation.

Can you comment? I mean, was there a kind of corrosion engineer went around and looked at these various tanks?

MS. LAURON: Specifically for these tanks, I'd say no. However, we do have -- I referenced a couple of handbooks that do have some data, and we can certainly provide that to you. There are some graphs that show the rate of corrosion for various types of steel over a period of time for various environments: industrial, rural, marine. So we can provide those to you if you'd like to see those.

MR. FORD: It's really a question of as being kind of the technical conscience of the NRC as to whether we can put our hand on our hearts and sign off and say, "Yes, this was done competently by a qualified corrosion person."

MR. AULUCK: I think applicant does have some additional information, but to respond to your question on consequence, if for whatever reason they find something, this first, one-time inspection, if they meet this acceptance criteria, it automatically

brings them into their second action, into the conditional evaluation report which spotted the collection action program which may require more inspections or create a regular program.

MR. FORD: I mean, just in this conversation that we've had just in the last ten minutes, I'm hearing that the dialogue going exactly as occurred at Ginna, and we asked the question. I forget what it was on, with galvanic corrosion. I've forgotten the specific incidence, and the licensee answered the question, not the NRC staff, and that worried me.

MR. AULUCK: Yeah, that's why I think we went back and requested about the staff to, you know, pull out the references for each material involvement conditions and see how the degradation can progress over the next ten, 20, 30 years from the operating experience of the industry.

And I think a couple of the references you heard from the handbooks are from there.

MR. FORD: Okay.

MR. AULUCK: And I'll have more probably in the next example where we have some more data.

MR. FORD: Okay, good. I think what we were hoping for in answer to this concern it had about

one-time inspections, there was quantitative analysis done of the amount of degradation, and I was hoping to see some numbers.

MS. LAURON: You're talking specifically to the tanks at Summer?

MR. FORD: Or whatever example you're going to bring out. We ask for give us a couple of examples, and I had hoped that it was understood that it would be quantitative examples.

MR. KUO: Okay, Dr. Ford. I think this example that Carolyn just described to you is to demonstrate what inspection may be used. In this case, I think she described that the more concern actually in this case is external corrosion rather than the air and water interface.

The staff's judgment is that the air-water interface corrosion problem is not as serious as external service. However, we want to make sure that judgment is correct, and that's where the one-time inspection is used, without the quantification, of course.

(Pause in proceedings.)

MR. AULUCK: Jim. Yes, please.

MS. STRNISHA: I'm Jim Strnisha from Division of Engineering.

The example I have here is heat exchanger inspections. Let me go over and see if there are any questions.

The heat exchanger is a one-time inspection program. It's for closed cycle, heated water, heat exchangers only, and these would include heat exchangers, such as ventilation and air handling that had treated water and air environment on the other side, and various lube-oil coolers which are treated water with oil on the other sides.

System purity on the treated water side is maintained by the water chemistry control program. These heat exchangers are specific for brass, copper, nickel-copper heat exchangers and brass components only. So it's a very specific program.

It's consistent with the GALL one-time inspection program and the selective leaching program.

The aging effects, plant specific industry experience was reviewed, and these were the possible aging effects for this component in this environment: erosion-corrosion, selective leaching, and fouling.

CHAIRMAN LEITCH: Now, in a heat exchanger, you've got internal-external corrosion on the shell?

MS. STRNISHA: Yeah.

CHAIRMAN LEITCH: Or the internal-external corrosion on the tubes. I mean, what are we addressing here?

MS. STRNISHA: Right here, other programs address those components in the heat exchanger. This one is only addressing the brass, copper, nickel, the soft heat exchanger components, the tubes and a few other things in there.

CHAIRMAN LEITCH: So this program is addressing the tubing?

MS. STRNISHA: Yeah, pretty much the tubing, and there may be some other brass components in here.

CHAIRMAN LEITCH: And we're talking internal or external on the tubing or both?

MS. STRNISHA: The internal, the treated water environment only.

CHAIRMAN LEITCH: Okay, okay. Thank you.

MS. STRNISHA: So looking at that, the three aging effects are erosion-corrosion. We looked at that one, and the main factor affecting erosion-corrosion is the abrasives in the water. So that's going to be negligible for treated water.

Selective leaching, purity in the water is going to be maintained well. So we expect that to

curve slowly over a long period of time.

And as far as fouling on these and in the pure water environment, we don't expect to see any fouling.

So these are possible aging effects. So what Summer did was put them in a one-time inspection program. So during your 30 or you 35, they'll go in and take a one-time inspection for these. If they find something, if there's an aging effect that's occurring, then they'll do additional inspections, possible periodic inspections later, and then if they don't find anything, pretty much they'll rule it out.

MR. RANSOM: Is flow accelerated corrosion considered in that program?

MS. STRNISHA: In erosion-corrosion?

MR. RANSOM: Flow accelerated corrosion, possible cavitation, that type of thing.

MS. STRNISHA: Well, yeah, this is specific for the erosion-corrosion with the abrasives, and, Mike, is that covered in another program for these heat exchangers?

MR. DANTZLER: Yes. Mike Dantzler.

Yes. That's flow accelerated corrosion. That's a different program, and that's for hot systems, two-phase systems. These are relatively low

temperature systems. The only erosion-corrosion that we could have in these systems is with the abrasives in there. We couldn't entirely discount them, but we keep treated water systems clean so that we don't think it's going to occur, but we can't entirely discount them. So we're going to look at them.

MR. RANSOM: Do these inspection programs look for things like cavitation effects, you know, which erodes away material at, oh, points of high velocity in the system?

MS. STRNISHA: Well, the FAC program would look at that. But the program that I'm addressing here, the heat exchanger program, what do we do? It would probably take a wall thickness measurement on these tubes for wear on the one-time basis.

MR. SIEBER: It would be quite --

CHAIRMAN LEITCH: So what you're saying is flow accelerated corrosion is not a credible aging effect in this type of a heat exchanger, not with brass. I mean, you wouldn't use copper-brass tubing in an environment subject to --

MS. STRNISHA: Yes.

MR. AULUCK: Yes, Dr. Ford did issue a report, I think, by Sandia which gives information on different mechanisms following and, you know, a

significant amount or make or general corrosion, and it also gives operating. They looked at a lot of LERs over the years, and they have like 44 percent, you know, falling was the aging effect; erosion-corrosion about 25 percent; general corrosion, 12 percent; fatigue, 5 percent.

So they have some information on the Sandia report. I have no looked at the report, but apparently there's some data on that from the operating history of the heat exchangers for several years.

MS. STRNISHA: And the last bullet, visual volumetric hardness one-time testings will be capable of detecting these aging effects, and as I said earlier, if anything is detected in year '30 to '35 before the period of extended operation, they'll reassess it, and I'll put it in the corrective action program.

Any questions?

(No response.)

MS. STRNISHA: Okay. Thank you.

CHAIRMAN LEITCH: To move off one-time inspections, I guess I had a question about opportunistic inspections of buried piping and tanks. It's not clear to me whether there is a commitment

here to -- well, certainly there is a commitment that if we're digging up the tanks or piping for other purposes we'll take a look at the condition of that equipment. But if we're not digging it up for other purposes, is there a commitment to do inspection of buried piping?

MR. AULUCK: Actually there is an actual experience on this plant. In 1992 time frame, apparently, they dug up the fuel oil storage tank, and they did a, you know, very substantial inspection, UT, of all sites, and that is also very positive. There was no degradation found, and on the piping, recently, you know, if I recall, in 1997-97 time frame, there was some modifications were to be done in the fire service area, and they looked at those very open, unfollowed insulation, looked at certain tees (phonetic) for changes, and as I understand, there was no degradation found. Maybe the applicant can substantiate that position.

PARTICIPANT: That's true.

CHAIRMAN LEITCH: But that's all opportunistic inspection. My question really is: suppose none of that occurs. Are we going to look at anything buried for the next 30 years?

MR. AULUCK: I think there's a program,

buried piping and tank inspection. I think, Carolyn, can you say is there anything specific on that.

MS. LAURON: As I understand the question you were asking, it's if there was just based on opportunity; if other than just based on opportunity, to do modifications to inspect the buried piping and tank; is that correct? Is that the question?

CHAIRMAN LEITCH: Yes, other than opportunistic.

I mean, I realize there's a commitment here that if they dig up something, they're going to evaluate its condition, but my question is suppose they are very fortunate and they don't have to dig anything up. Is there any requirement or any commitment to look at buried equipment, either tanks or piping?

MS. LAURON: Well, in terms of the piping I would say no because the staff has taken the position that for them to excavate for whatever reason, other than -- well, not that they wouldn't be able to damage the coatings or the wrappings on the pipes during modifications. To actually have them go in and dig out, they may do more damage to the coatings, but to do these in sections.

And since the piping is also coated, it's

cathodically protected. Even though they don't take credit for that cathodic protection, staff believes that the type of degradation that they would see would not be as significant.

CHAIRMAN LEITCH: So the answer is no.

MS. LAURON: Correct. Sorry.

MR. FORD: Let me ask another question, again, before we close out on this one-time inspection. It's more of a general question maybe to both of you.

Time and time again over the last 30 years that I know of both in and out of the nuclear island, you have had unfortunate degradation occurrence, and all of them that I know of before the even was "it's not likely to occur." I can think of it in turbines. I can think of it in the reactors, and other components.

Every one of them it was not likely to occur, and yet it did occur. Is anyone within the staff looking at the question of what do we have to do to the system before we get an occurrence, like a chloride transient or whatever it might be?

And the rigor at which you're going to go that inquiry will depend on what is the risk. Is anyone doing any such analysis?

How much do I have to push the system before I have a degradation? And what will the risk be? What will the consequence be if I had such a degradation?

MR. KUO: Dr. Ford, if I understand you correctly and that you address this in a general term, it has nothing to do with Summer.

MR. FORD: Absolutely correct.

MR. KUO: And I will answer it in a way. This is a version.

MR. FORD: Needs someone to do a quantitative corrosion engineering analysis.

MR. KUO: Okay. We do the aging management review and look at the system components first. Okay?

And then we look at if there is a probable aging effect on certain components of the materials. We really look at it and say if I've got carbon steel piping, I know that is going to corrode. I don't care whether anyone tells me that there's no corrosion or nothing happened or not. There is a corrosion based on the experience.

Corrosion is going to occur on carbon pipe, on this pipe. Therefore, we will require an aging management program. Okay?

In those rare cases that we really cannot positively say that there is going to be an aging mechanism on this component, then we say, okay, you could use a one-time inspection to verify that or to confirm that. That is a very rare case.

So to answer your question, Dr. Ford generically, it is that for those aging mechanisms in any component or materials we will require an aging management program.

Now, for those rare cases, there is really very improbable occurrence, this aging effect occurred, in any of these materials or components. We would say you use a one-time inspection to confirm that, okay, in case, just in case that our judgment was wrong.

Something happened. We still have this regulatory process to catch that. We have the Appendix B corrective action, program there on site. There's an ongoing regulatory process. It doesn't mean that we don't have anything to deal with it.

MR. FORD: I guess I've been bitten so often in the last 30 years by "it will never occur. I'm so far away from," "my margins are so great," and they've done it every time. You get killed by such an occurrence.

The GE BWR turbines never crack, and they do. It becomes an industry problem.

MR. BONACA: But one thing that is important to give also further confidence to the one-time inspection concept is that you're doing one-time inspection on separate components on a consistent basis across the board. So, for example, you're doing small bore inspections, and you're going to look for evidence that confirms that you're not going to have a degradation in that system.

Now, as you do that, you're doing it for many plants there, and the staff has expected that these inspections are not risk based. In fact, you have to look at the most acceptable areas.

Should you begin to see, in fact, that you have significant degradation at Plant A, Plant B and Plant C, I would expect that you would move to a programmatic approach to the resolution of the issues. It means now you institute an inspection program on a certain frequency.

So, I mean, I think the confirmation process, it's not only, again, one unit, but is many units which are all in this license renewal process. So as I said, I'm not --

MR. FORD: Mario, I agree with you

absolutely. Unfortunately I don't see them asking "what if" questions, and that's what I'm concerned about.

MR. KUO: Yeah, I understand that, and what I'm trying to say, Dr. Ford, is that the regulatory process is an in depth kind of a process that we have built up so many steps to deal with the problems.

I give you one example. We really cannot possibly consider all probability. The design, for instance, we designed the piping according to ASME code. We did structures according to HEI code.

Okay. However, just for that improbability that it may fell, even though our design criteria are very conservative, it could fell; it could weep; it could crack. So we have ISI in place to deal with that kind of problem.

We have a maintenance program to deal with that problem. If we are so sure the design criteria would do the job, then the structure would never fail. The piping would never crack, but it's not -- the reality is not such. We know it is going to. For some reason it is going to crack. Okay?

Therefore, we have in-service inspection program. Therefore, we have maintenance program. We

do our best, try to deal with this kind of unanticipated situation, but we cannot handle everything.

MR. SIEBER: It seems to me that there is a sort of graded approach. You know, the high energy and high pressure systems under the ASME code get intense inspections through the ISI program and very controlled conditions for repair, but if you're looking at fire lines and cooling water lines where the consequence of a broken line is a wet hole in the ground, you know, you can tolerate a less expensive inspection program because the consequences really don't amount to too much.

And I think that's what I see in these aging management programs. You put the effort where the consequence can be severe, which is reactor coolant system, main steam sys. generator, steam generators, and so forth.

So to me I think the balance is there.

MR. AULUCK: Yeah, I think if one can say the consequence is severe, there's no way it can be a one-time inspection.

MR. FORD: I remember when we first started this license renewal, and this is the last comment I'll make on this one, in the fire protection

system, I remember there was a big argument that went on about this is going to be a one-time inspection, and then they raised the question about, well, what happens if a whole lot of corrosion crud is on the ID of the piping and when you was the fire protection system you gum up your whole space systems.

I remember this was a topic that came up for discussion, and the argument that the staff made was, well, these are stagnant lines. They'll be de-aerated, and you'll stop all of the corrosion.

Well, that well could be the case, but what happens if they are not always de-aerated? What happens if they don't have an inhibitor in the system, et cetera, and then they started pushing on that question. They didn't get a foolproof answer.

So I agree that by the book it shouldn't corrode, but if you don't go by the book, then you could crud up your whole fire protection system.

MR. SIEBER: On the other hand, if you have flow in your fire protection system all the time, that means you've got a fire someplace, and once you stop flow, which sprinkler heads in various vales and barriers stop the flow, then you deplete the oxygen in the water and corrosion then goes to a very minimum amount, you k now.

MR. FORD: It's that more in-depth discussion I'm just challenging the system.

MR. KUO: I would say if we could have some time, let us discuss among ourselves, and we will schedule another separate briefing with the staff to talk about this. Yeah, I know exactly, I think, what you are talking about.

MR. FORD: Good. Thank you.

MR. KUO: And we will do that.

CHAIRMAN LEITCH: Raj, I think we're ready to move into the --

MR. AULUCK: Yes.

CHAIRMAN LEITCH: -- TLAAs.

MR. AULUCK: Yes, the final part of our presentation, and Kimberly Corp will make the presentation.

MS. CORP: Section 4 evaluated the time limited aging analysis on the Summer license renewal application, including reactor vessel neutron embrittlement, metal fatigue, environmental qualification of electrical equipment, concrete containment, attendant pre-stress, containment liner plate, and penetration fatigue analysis, as well as other plant specific TLAAs.

Section 4.2 evaluated the reactor vessel

neutron embrittlement. The three TLAs identified for radiation embrittlement were reactor vessel upper shelf energy, pressure thermal shock, and pressure temperature limits.

The first TLA identified was reactor vessel upper shelf energy. Appendix G of 10 CFR 50 requires that reactor vessel beltline materials have upper shelf energy values throughout the life of the vessel of no less than 50 foot-pounds. For the limiting beltline material, the staff calculated the upper shelf energy value for the extended period, 60 years, using Reg. Guide 1.99 and found it to be 53 foot-pounds.

For the limiting weld, the staff calculated the upper shelf energy value to be 59 foot-pounds.

This independent staff analysis confirms that the applicant's analysis satisfies Appendix G.

Commitment 31 states that the licensee will update their analysis with the removal of the capsule from the latest average.

MR. BONACA: The question I had was the staff did the calculations. I mean, did the licensee do the calculations?

MR. AULUCK: They also did it, and the

staff independently verified it, and they have taken the last capsule out during this last outage.

MR. BONACA: The reason why I asked the question is in some cases it says they have not completed the calculations yet. They have established the method that they will use.

MS. CORP: Right. No, they have calculated the values, and they will be revising them based on the latest information collected from this capsule.

MR. SHACK: Just as a general question, do they have to pull the capsule? I mean, if I got these answers, I might be inclined to quit.

MR. ELLIOT: As far as capsules are concerned, there's an ASTM standard that we endorse, ASTM E-185, and it says when you're supposed to take out capsules, and it depends on how much radiation embrittlement is projected. This plant has very low radiation embrittlement. So they probably don't have to take out a lot of capsules.

They've already taken out four of them. They probably have taken out enough, but they're committed now to take out two more. So they're probably doing a lot more than the standard requires.

MR. SHACK: That might buy them some

relief on their pressure temperature limits.

MR. ELLIOT: I mean, it might, but this plant has very low copper, and that's why you can see the PTS values are really very, very low, and so we're not going to get a lot of embrittlement here.

It would be surprising if they took out a capsule and they saw a lot of embrittlement. So far four capsules haven't shown it.

MR. SHACK: But just on my sort of general question, how many specimens are there in a capsule? When do I trump the Reg. Guide 199 kind of limit which is based on my collective wisdom and everything I know with a bunch of data that's probably got scattered up the wazoo when I run the tests?

I mean, I'm sure that's all addressed in the standard. I just don't know it very well.

MR. ELLIOT: Well, not, the standard doesn't address that. The Reg. Guide 1.99 addresses that. The standard just says when you take out the capsules. It tells you how many samples to put in the capsules, like a minimum of eight to do a Sharpy curve, a few tensile specimens, that type of information, dosimetry, what kind of dosimetry to put in, and that's all there is in that standard.

The reg. guide says that after you test

the capsules, it says based upon the results how to analyze it, and that's what your question is, and it tells you how to analyze it.

Now, it's staff experience it's very rare that the shift of the uppers shelf energy would not be bounded by the reg. guide methodology. There has been cases though, Beaver Valley, where it didn't, and so the staff had to work out a methodology that wasn't in the reg. guide.

And that's the whole purpose of the surveillance program. It's very similar to the question about the ISI. We have an ISI program. I just wanted to get this in. We have an ISI program --

(Laughter.)

MR. ELLIOT: We have an ISI program that says you do some kind of inspection, and we don't expect them to find anything. That's the point of the inspection program. It is to look for things that we don't know about.

Well, when they find it, that's when we have to change the inspection program, and this is the same thing with this. We have guidance on the surveillance program here, and we expect them all to fall within the bounds of the data, but if they don't, that's when NRC takes out its collective wisdom and

starts to change things. That's how it works.

MR. AULUCK: Moving on.

MS. CORP: I have the second TRA identified as pressurized thermal shock. Materials should provide adequate protection against PTS events if reference temperatures are less than or equal to the screening criteria. For base metal, intermediate shell plate and axial weld, the PTS reference temperatures should be less than or equal to 270 degrees.

Staff assessments of PTS include application of all applicable Summer surveillance material data in the reactor vessel program, and the staff calculated the PTS reference temperature for the shell plate toe be 158 degrees and for the axial weld to be 110 degrees.

These values are well within the specified criterion of 10 CFR 5061.

CHAIRMAN LEITCH: Are they also reasonably close to the licensee's calculations?

MR. ELLIOT: Yes. They're just about exactly right.

CHAIRMAN LEITCH: Okay. Thank you.

MR. SHACK: Is this a combustion vessel, engineering?

PARTICIPANT: Chicago Bridge and Iron.

MR. SIEBER: It is a late vessel plant, an '82 plant.

MR. AULUCK: Okay. Go ahead.

MS. CORP: The third TLA identified as pressure temperature limits. As Section 4.23 of the LRA states, the applicant will submit PT curves for the period of extended operation for approval pursuant to the license amendment requirements of 10 CFR 5090.

The technical specifications will also be updated as required by Appendix G of 10 CFR 50. This is Commitment 32 in Appendix A of the Summer ICR.

Section 4.3 of the SER evaluated metal fatigue. Reactor coolant system components at Summer are designed to Class I requirements of the ASME code. As Dr. Cheng has mentioned earlier, three components may exceed the design base fatigue usage factor during the period of extended operations. Those components are the charging nozzle, the alternate charging nozzle, and pressurizer/surge line reactor coolant loop nozzle.

In accordance with the thermal fatigue monitoring program the applicant must take corrective actions prior to exceeding the fatigue usage limit for these components.

In the SER, Commitment 33 stated that the applicant's commitment for metal fatigue included transients will be tracked by the thermal fatigue management program. They'll perform evaluations in alignment with NUREG CR-6260 components for environmental fatigue prior to the period of extended operation, and components with CUFs protected to exceed one will be either reanalyzed or replaced prior to exceeding cycles of transience tracked by the thermal fatigue management program.

Section 4.4 of the SER evaluated environment qualification of electrical equipment, and the applicant's EQ program is consistent with GALL. The staff concluded the EQ program will continue to manage equipment in accordance with 10 CFR 5049 and meets Option 3 of 10 CFR 5421(c)(1).

Effects of aging on the intended functions will be adequately managed for the period of extended operation.

Section 4.5 of the SER evaluated the concrete containment tendon loss of prestress. Prestress losses were estimated for 60 years. The applicant provided trending analysis in response to REI 4.5-1, and the staff considers that applicant's actions adequate during the period of extended

operation and are consistent with GALL.

Section 4.6 evaluated the containment liner plate and penetration fatigue analysis. Staff concludes that the TLA for the reactor building liner stress has been projected to the end of the period of extended operation, and the staff concludes that the TLAA for the piping penetration flat plate fatigue remains valid for the period of extended operation as well.

And finally, Section 4.7 of the SER evaluates the other plant specific TLLAs. I'll briefly mention the service water intake structure settlement. Since this is unique to LLA, not seen in other applications, as the applicant had discussed earlier in their presentation, excessive nonuniform settlement of the intake structure occurred during construction which caused considerable cracking. This settlement was analyzed in a service water pump house calculation, which was originally based on a plant design life of 40 years.

Therefore, this issue meets all six criteria of 10 CFR 54.3.

In the application, the applicant indicated that the calculation was revised to account for the period of extended operation. No description

of the analytical methodology or summary of the results utilized in the TLA calculation was provided in the LAR.

So during the AMR inspection, the staff reviewed numerical calculations demonstrating that changing from a 40 year operating life to a 60 year operating life has no impact on the conclusions reached in the original calculations.

Summer has committed to a service water structure survey monitoring program and an underwater inspection program

And this concludes our presentation.

MR. SHACK: I have a question on the leak before break, which I thought was a good section in the ECR. I was sort of looking forward to seeing how they were going to treat LBB for a PWR that now has stress corrosion cracking.

But did I lose count? Are there two mitigative measures here in place or have we suddenly changed the criteria?

MR. ELLIOT: I'll have to look at it.

MR. SHACK: Okay. Now, the issue here, are you concerned about the leak before break from the safe ends?

MR. ELLIOT: For the safe ends.

MR. SHACK: Through the hot legs? You have an active degradation on our criteria.

MR. ELLIOT: Two mitigation measures.

MR. SHACK: Two mitigation effects. They have the stress improvement, and do they have any others? No, I guess they don't.

MR. ELLIOT: I'm looking forward to Farley's evaluation.

MR. SHACK: So that's where we stand.

CHAIRMAN LEITCH: I didn't lose count.

MR. AULUCK: Okay. Continue, sir.

MR. BARTON: I have a question. This is the first application I've reviewed that didn't have any open items. Now, is this because the licensee or the applicant succumbed to NRC arm twisting or what? Can you explain to me why there's no open items in this?

This is the first one at this stage that there are no open items.

MR. AULUCK: That is true, and part of the reason could be we pushed ourselves, we published the applicant, and had an opportunity to discuss things, and agree upon, and you know, long hours. You know, but there have been a couple of applications before where we didn't have too many either. Turkey Point is

one.

MR. BARTON: Yeah, but this is the first one I didn't see any at all.

MR. AULUCK: Yeah, this is the first time. We were not shooting, but it has happened. You always want to do that, but you know, I think credit goes to the staff and credit goes to the applicant for, you know, trying to address technical issues in a fair way.

MR. KUO: I would say a large part of the reason is really lessons learned. It's being so many previous applications already, and they closely follow the previous applications and how it worked and all of that.

I think that part has a lot to do with why we don't have open items here. I think this will probably be the case later on, you know, for the future applications. You probably won't see many open items.

MR. BONACA: Your generic guidance, you know, issues, in fact, have not increased in numbers, right?

MR. KUO: Has not increased in numbers, no.

MR. BONACA: And so there should be pretty

well a familiarization of open issues with the industry that should lead to this kind of expectation hopefully.

MR. KUO: I believe so unless there are some unique cases. Otherwise, it's pretty stable now.

MR. BONACA: Yeah, that's good.

CHAIRMAN LEITCH: Did you have a comment you wanted?

MR. LABORDE: Just from the licensee's side of it, I challenged Al and his team early on in our process to get to the SERs with open items with no open items and to get there required numerous meetings with the staff, whether it was in person or phone calls, to resolve the issues

We set out as a goal to get there, and I think that the process that we went through, being this kind of transient level of GALL status plant was challenging, but like I said, it was our target, and we were pleased to get there.

MR. BARTON: Well, I'm glad to hear that because I would have been concerned if you had finally said just to hell with it and were just going to do, you know, whatever the staff asked for, and that's apparently not the case.

CHAIRMAN LEITCH: I would like to take the

couple of minutes we have remaining now to ask the subcommittee members to give me responses to basically two issues. One is is there any reason for an interim letter in this case, and are there items, residual issues that you would like to hear discussed at the full committee meeting whenever it occurs?

So, Jack, do you want to start with those?

MR. SIEBER: I don't see the need for an imprimatur, and I can't think of any residual issues that I think has not been covered by the applicant in his application and the SER. In fact, I found this application and this SER to be one of the easiest ones to review. I thought it was very well done.

And so the answer to both questions is no.

CHAIRMAN LEITCH: Okay. Bill?

MR. SHACK: No, no.

CHAIRMAN LEITCH: Okay. Peter.

MR. RANSOM: No, no either.

CHAIRMAN LEITCH: Mario?

MR. BONACA: No need for an interim letter. I felt that the application hopefully is as small as they will ever get.

CHAIRMAN LEITCH: This is the smallest of all the applications we have received so far.

MR. BONACA: Was very condensed. I wish

somewhere in the first page they would have told me what kind of plant, what kind of rating you had. I mean it was that condensed.

But I think tha t--

MR. SIEBER: In the future that's all that will change.

MR. BONACA: That combined with an SER that was quite descriptive, I think, was enough information there to cover all of the bases. I think that I was pleased to see that there were no open issues, and so I don't see any need for an interim letter, and I think that there is no new items we need to have.

The full committee, just maybe a summary of what we've seen here.

CHAIRMAN LEITCH: Right. Jack, John?

MR. BARTON: No interim letter. I though it was a good application. The only problem I had in the review of it, and I mentioned in my comments, is that in the tables this application used generic terms like tanks, and it was very difficult when you were reading this section to go find out which tank were they specifically talking about, whereas applications in the past that had listed specific tank, condensate storage tank, you know when you went to the table, you

know, exactly what tank they were talking about and what the program was.

I found a problem here because they used a lot of generic terms, but in nothing having their drawings, you couldn't figure out which tank were they actually talking about. That was the only problem I had in reviewing this application.

But I don't think you need a letter. I have two questions in my submittal to you, in my comments, that I think you ought to submit to the staff and ask -- it's number two and three -- and ask the staff to kind of answer those and get back to the committee on.

I didn't want to take up time today because it would have needed to go back and forth within tables in the application, and that would have taken too much time, but there's two questions I think you can send to the staff and ask them to get back to the ACRS on.

CHAIRMAN LEITCH: Okay. Do you want to --

MR. BARTON: I highlight them in yellow there.

CHAIRMAN LEITCH: Yeah, okay. I think the application was good and the presentations were good. I appreciate that.

I think as far as the full committee meeting, I recognize it will be condensed. I think we usually allocate -- what do we allocate? -- not more than an hour and a half or something like that. So obviously the presentations will have to be somewhat more condensed.

I do think the issues that you opened up with, although perhaps not directly related to license renewal are certainly issues that will be of interest to the full committee, and you ought to go over those again, the hot leg weld issue, the heads, upper head, lower head, the sump blockage issue. There are three hot topics, and certainly they'll come up again, and we should just for the benefit of the members that were not here. I think that's important.

I think the thermal fatigue, the three limiting situations that were mentioned, it would probably be good to go over those again just to mention what that situation is.

And I think the settling of the pump house would be an important issue to discuss. I think the drawing that shows the configuration of the lakes and the dams and so forth I certainly found helpful, and I think the rest of the committee would find that helpful to repeat that so that we understand the

configuration of the water works.

So that's about it, I guess. Any concluding remarks, P.T. or others?

MR. KUO: Well, thank you very much for your time. I think this is, like you all said, an application that's well returned, and we also appreciate the applicant's cooperation throughout the course of the review.

CHAIRMAN LEITCH: Okay. The subcommittee stands adjourned then.

(Whereupon, at 11:31 a.m., the subcommittee meeting was concluded.)