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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT LICENSE RENEWAL SUBCOMMITTEE MEETING

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WEDNESDAY,

APRIL 9, 2003

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ROCKVILLE, MARYLAND

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The Committee met at 8:30 a.m. in Room T2B3, Two White Flint North, Rockville, Maryland, Mario V. Bonaca, Chairman, presiding.

ACRS MEMBERS PRESENT:

MARIO V. BONACA	Chairman
F. PETER FORD	Member
GRAHAM M. LEITCH	Member
STEPHEN L. ROSEN	Member-at-Large
GRAHAM B. WALLIS	Member

NRC STAFF PRESENT:

SHER BAHADUR	Designated Federal Official
JOHN T. LARKINS	Executive Director, ACRS/ACNW
SAM DURAISWAMY	Technical Assistant, ACRS/ACNW
HOWARD J. LARSON	Special Assistant, ACRS/ACNW
TIMOTHY KOBETZ	Senior Staff Engineer, ACRS
P.T. KUO	NRR/DRIP/RLEP
NOEL DUDLEY	
STUART BAILEY	
JAMES MEDOFF	
DUC NGUYEN	NRR/DE/EEIB
JOHN FAIR	NRR/DE/EMEB
SIMON SHENG	
GREG GALLETTI	NRR/IEHB
CAUDLE JULIAN	NRC Region 2
DAVID JENG	NRR/DE/EMEB
JACK CUSHING	
J. RAJAN	NRR/DE/EMEB
RONNIE FRANOVITCH	

ALSO PRESENT:

STEVE HALE	Florida Power and Light
BRUCE BEISLER	Florida Power and Light
ANTONIO MENOCAL	Florida Power and Light

I-N-D-E-X

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

8:31 p.m.

CHAIRMAN BONACA: Good morning. This is a meeting of the CRS Subcommittee on Plant License Renewal. I'm Mario Bonaca, Chairman of the subcommittee. The CRS members in attendance are Graham Leitch, Peter Ford, Graham Wallis, and Stephen Rosen.

The purpose of this meeting is to review the report with open items related to the application for renewal of the operating licenses for St. Lucie Units 1 and 2. The subcommittee will gather information, analyze relevant issues and facts, and formulate a proposal, positions and actions as appropriate, for deliberation by the full committee.

Tim Kobetz is the CRS staff engineer for this meeting. The rules for participation in today's meeting have been announced as part of the notice of this meeting previously noted in the Federal Register on March 19th, 2003. A transcript of this meeting is being kept and will be made available, as stated in the Federal Register notice. It is requested that speakers first identify themselves, use one of the microphones, and speak with sufficient clarity and volume, so that they can be readily heard.

I would like to point out that copies of these presentations are in the back of the room. In addition, a copy of the St. Lucie license renewal application is also available for reference in the back of the room. We have received no request for time to make oral statements or written comments from members of the public regarding today's meeting.

We will now proceed with the meeting. I'll call upon Mr. P.T. Kuo, Program Director of the NRC Division on License Renewal and Environmental Impacts for opening remarks.

MR. KUO: Thank you, Dr. Bonaca. Good morning, everyone. Like you said, my name is P.T. Kuo. I'm the Program Director for the License Renewal and Environmental Impacts Program. On my right is Dr. Sam Sun Li, who is the Second Chief for License Renewal Section. The staff is ready to brief the committee on the safety variation of the St. Lucie license renewal application today.

The project manager for this review is Mr. Noel Dudley. I'm sure he is a trusted familiar face to you all. He is going to lead the staff presentation with the support from the key reviewers, either with him on the table or sitting in the audience ready to answer any questions you might have.

There were 11 open issues at the time that we issued the draft to SER. You have a copy on hand. Since then, all these issues have been resolved. Mr. Dudley is going to brief the committee on some of the issues. I also want to point out Mr. Caudle Julian, the team leader from Region II, is the team leader for the St. Lucie inspection, and he will be making, also, the presentation to the committee after lunch the findings of his inspection.

We are also going to brief the committee today on the staff's interim guidance development process. As we promised last time, Mr. Jack Cushing is going to make that presentation.

In the last meeting, I believe, the committee indicated that you are interested in hearing from us, the staff, about the operating event experience process, and we have contacted responsible members in the staff. They will be prepared to come to the committee in the May committee meeting. So there will be a presentation in May on the operating event experience process from the staff.

So with that, if you don't have any questions, and, with your permission, I would like to turn the presentation over to Florida Power and Light for an overview of their application and then followed

by the staff presentation.

CHAIRMAN BONACA: I have a question, which I would like to get out of the way. As I opened the application, page 21-6, the first thing that caught my eyes was seismic II over I is not in scope; that's what the application says. So I said here is another issue that was supposed to be closed generically, and now it's still open. Same thing I found about SBO and, also, housings for dampers and fans.

So, in working with this stuff, I asked for some clarification. I was led to page 108 of the SER, where there is documentation of an interaction. Requested for additional information, and I'm satisfied that the components were put in scope, particularly segments of piping that could possibly interact with the components.

So, now, then I went back to the FSAR supplement. I couldn't find it there. Then I went back to the SER, and I looked at the Tables of Commitments that you now add, which I think is a very good initiative, but there is no mention of that there.

MR. KUO: I believe Noel can address those comments later on.

CHAIRMAN BONACA: Well, all I'm trying to

understand is or what I was told was that other site, this segments have been brought into license renewal scope. Therefore, there is a document somewhere that says these components are there.

MR. DUDLEY: Yes, I can speak to that.

CHAIRMAN BONACA: I would like to hear that because, again, we're talking about this endless number of commitments here that are interspersed into these documents. It's obvious right now, and I am not going to argue with that, that the license renewal application documents is obsolete by the time that the SER is given because there are a lot of new commitments that are not really documented there. Where are they documented? I mean, do you give me comfort that, 10 years from now or 15 years from now, when you walk into license renewal, the applicant will remember that those additional commitments were made or the staff will remember when they're interspersed? I don't understand.

MR. DUDLEY: Yes, I can make an explanation. Noel Dudley, License Renewal. The SER, in a sense, is a high-level document that identifies what information the staff used to reach its decision that the application was acceptable, and that does, the SER does provide you information on locations of,

in this case, components that were brought into scope in response to an RAI. The listing of the components that were brought into scope in the RAI's is on a docket and is available, and I believe everyone did receive portions of the RAI's that identified additional components. So that's referenced in the SER and is available on a docket if somebody, in the future, wants to go back and look at the details of what components were brought within scope and which components received aging management reviews in the associated aging management programs, and it's very difficult to get all of that information into the SER and make the SER a readable document.

CHAIRMAN BONACA: No, I understand that. But certainly, if I had seen in the table in the back of the SER, which is additional commitments, just a statement, it says "added elements to comply with II over I seismic" or "seismic II over I closed," it would help me, as a reviewer. I mean, I view myself as almost like a member of the public that can only spend two days reviewing an application of this size, and I need to have some help in the being pointed out where issues are closed or open, and it would be helpful.

Now, I want to recognize that that table

in the back of the SER is a significant help and improvement, so I would just encourage you to use it, even to identify the resolution of issues that it would really be noticed by us right away because they were measure issues of the previous application.

MR. DUDLEY: As it turns out, out of the 79 additional components or structures that were added to the scope of license renewal, 70 of them are result of the responses to the II over I station blackout and fan and damper housings. So I can see where we could very easily add that statement in the commitment section to identify what major components were.

MEMBER LEITCH: I had a similar question right on that very same point. A number of the applications we've seen in the past, where they had non-safety systems in a II over I situation, they looked at every place where a non-safety system ran through a seismic Class I building and considered that entire portion of the safety system to be within the scope.

Now, from reading this, it seems as though that's not exactly what St. Lucie has done, but, rather, they've done it on a more spatial basis and just certain portions of non-safety systems that are running through seismic Class I buildings that are

included in scope. And I guess my question just, perhaps, further on Mario's point is do we have documentation, you know, clear documentation on the docket as to exactly what portions of non-safety systems are in scope and which ones are not. In other applications, they just kind of said any part of this system that runs in a seismic Class I building is in scope, but I don't think that was done here.

MR. HALE: Yes, let me speak to this, if I could.

MR. DUDLEY: I'll just give a broad overview. That will be discussed in more detail when we talk about the scoping screen methodologies, and that was looked at in detail during the scoping and screening audit that Greg Galletti will talk about later in the presentation. I can turn that over to Steve.

MR. HALE: In the area of scoping and screening, you know, the application is only a presentation of all the detailed technical information that we maintain on-site. One of the things we chose to do early on was reflect license renewal boundaries on our PNID's, permanent plant drawings. So, you know, every so often, PNID's are submitted to the NRC as part of the update process, and on those PNID's,

you'll see license renewal boundaries, even for these II over I.

Now, in the scoping area, we chose that, as these volumes, we've got a bookcase full of technical documents which support what we have. They're Q8 engineering-type evaluations, which support the information we submit. And in the scoping area, we actually revised our technical documents to reflect those changes and identified any permanent plant documents that would have to be revised as a result of that. So it's really at a level below the SAR, but it is incorporated into our documentation, so we have all that stuff documented.

And, as part of the scoping and screening inspection, the folks came in and actually looked and walked down those portions of the piping to verify that we had, indeed, captured the appropriate piping in the scope of license renewal and that it was adequately reflected on the drawings.

To speak to the fact that we hadn't addressed the II over I, the station blackout and the -- what was the other -- damper housings, we were already into the technical documentation aspect or the technical document preparation for St. Lucie and it was just one of timing. We actually started doing our

evaluation on II over I, station blackout, and the housings based on what was done at Turkey Point, so that we were able to address it at the RAI stage, rather than the open-items stage for St. Lucie. And anything that we do forward from here, we would have gone ahead and put in consistent with the staff guidance. So it was really a question of timing for us for St. Lucie.

MEMBER ROSEN: I have a question on P.T.'s opening remarks. I was listening for whether or not you're going to talk to us about the ROP status of St. Lucie any time today?

MR. DUDLEY: Yes, that's built into the presentation.

MEMBER ROSEN: When is that?

MR. DUDLEY: I think that's before lunch. MEMBER ROSEN: Item four? Okay. Thank you.

MR. DUDLEY: Any more questions?

MR. HALE: My name is Steve Hale. I'm the License Renewal Manager for Florida Power and Light. I was responsible for Turkey Point and St. Lucie license renewal. It's good to see a lot of the members that actually visited Turkey Point.

With me today is Bruce Beisler, who is our

civil lead. There were some questions that were presented to us early that there wanted to be discussion relevant to concrete subject to ground water, so Bruce is here to discuss that.

Also with me is Tony Menocal, who is our technical lead. He was responsible for development of all the technical documents which support our application.

What I'm going to talk about today is background. I will talk about the scoping and screening process, but since it was, essentially, the same one that we used for Turkey Point, I would like to focus more on the aging management review, aging management program, and TLAA areas, if I could. I will go through the scoping and screening process, but I would like to emphasize it's just like the one we used for Turkey Point.

One of the things I'll get into in the aging management review programs is the GALL report was issued while we were preparing the St. Lucie technical documents and application, and we had a request for Chris Grimes to at least try to address the deltas between our report and what was in the GALL report. Although we don't follow the new SRP format, we're consistent with the hot level on the SRP, but

some of the details we did address GALL in the application, and we did credit GALL for some of our programs.

With regard to license renewal FPL, I've been involved with license renewal since about 1992. I was on the NEI task force, and I was also on the Westinghouse Owner's Group license renewal group. The Turkey Point license renewal application was submitted in September of 2000. We initiated the technical work. We essentially took the same technical team that had done the evaluations for Turkey Point and moved them to St. Lucie when they actually started doing that work up at St. Lucie.

We submitted the St. Lucie license renewal application in November 2001. And just a note here, we did receive our renewed licenses for Turkey Point on June the 6th, 2002.

The guidance requirements, these are fairly standardized now with regards to license renewal. 10 CFR Part 54, the SRP has been issued now, which it hadn't before with Turkey Point, the GALL report, the Reg Guide, NRC position letters on generic issues, as well as now the new staff guidance letters and 95-10.

With regards to the technical work that's

performed on-site, we piloted our procedures in 1996 in support of the Turkey Point effort. We structured our procedures out of making the best use of the tools we had available, our electronic databases, our PNID's, our SAR, and our DBD's. We made information trips to other applicants that were active in the license renewal area, and we spent a lot of time with the Duke folks because, early on, Oconee seemed to be more in line with the type of thing that we wanted to do, although we felt we improved on their techniques.

What we try to incorporate, and this really goes to the issue of station blackout, II over I the results of the NRC review of Turkey Point license renewal application, also lessons learned, RAI's and RAI responses, and resolution to generic issues were factored into our procedures, where they were available and where we could.

Because we were in the process of negotiating and trying to resolve the station blackout issue and the II over I issue for Turkey Point, we really didn't know what the end point was going to be. And before we actually went down that path, we wanted to make sure we had a good idea as to what was going to be done in terms of resolution for Turkey Point before we did that for St. Lucie because there's quite

a bit of engineering work involved.

One thing we did want to flag is that we did do all of our technical work under our quality assurance program. The technical documents were subject to auditing by our QA group. Turkey Point, they participated at various stages, and, at St. Lucie, they tended to focus on differences between St. Lucie one and two was one of the areas they took a look at. But it was done under the QA program.

MEMBER FORD: Steve, I know you just talked about TLAA's in the previous diagram, you were talking about lessons learned, etcetera, etcetera. You'd assume, therefore, the number of open issues would be decreasing with time. I don't know if that's the case here. Are we, in fact, learning from the past? Could you make a comment on the number of open issues? I know they've all been resolved at this time.

MR. DUDLEY: Yes. Noel Dudley, license renewal. For Turkey Point, there were about, I've got it later in the presentation --

MEMBER FORD: Okay, fine.

MR. DUDLEY: But there was about a 70 fewer RAI's for St. Lucie as there was at Turkey Point.

MEMBER FORD: Okay.

MR. DUDLEY: The assessment of why that is is a longer discussion.

MR. HALE: Yes. I think my perception is that, you know, you reach a deadline to issue the SE, and these items were just, we essentially, between us and the NRC, ran out of time to resolve them through the RAI process, so you just kind of draw a line in the sand, the issue of the SE with the open items, and, in the process, we've been able to resolve them. So I don't think there were really hard spots. There were more clarifications and more information was required from us.

But from the RAI process, I felt we had a very positive interaction. We learned quite a bit from Turkey Point. We followed the same process where we would sit down with a staff in open public meetings to review draft RAI's, and if we could point to correspondence where that information could be addressed, then we were able to avoid having an RAI issue. And on the same tact, we issued draft RAI responses and then had open public meetings with the staff, where we would go over those and make sure that our responses were addressing, indeed, the concern of the reviewer. We've always taken the tact that it's

better to have that face, one-on-one interaction with reviewers to really understand what the issues are.

So as a result of that, we had about 150 so RAI's for St. Lucie, and we had over 200 at Turkey Point. I think there was quite a bit of lessons learned there. And I look at it also from the standpoint, you know, look at licensing fees. The review of St. Lucie is significantly lower in terms of licensing fees versus Turkey Point, and I think that's an indicator that our review is getting more efficient and better because they're essentially the same format, the same type of documents.

As far as the application format, it's the same as Turkey Point. We included admin information in Chapter One, the scoping and screening is covered in Chapter Two. Chapter Three covers the AMR's. And Chapter Four is the time limit of aging analysis. It's very similar to A&O, Turkey Point, the Duke units, McGuire and Catawba, and Surry and North Anna.

NXA is UFSAR supplement. In the case of St. Lucie, that's two supplements because Unit 1 and Unit 2 each have their own SAR. Aging management programs are prescribed in Appendix B. Appendix C is just a summary of the process we utilized for establishing aging effects for non-Class I components.

Appendix D is spec changes; we had none. And then the environmental report was the separate document attached to the application.

Our source documents, we used the UFSAR; our licensing correspondence, we have an electronic database with all of our correspondence from the beginning; our design basis documents for Unit 1 and Unit 2, our electronic component database, which has controlled engineering fields in terms of safety classification, you know, tag number, this sort of thing. Our drawings, primarily, are PNID's and our control wiring diagrams. And in some cases, we actually got into other documents at the plant, but these are the primary information sources we have for scoping and screening.

Our methodology is described in section 2-1. Again, it's the same as we utilized for Turkey Point, and it follows the approach that is in 95-10. In the scoping area, what is the purpose? It's really to identify, on a system and structure basis, which ones are within the scope of license renewal. Again, to reiterate the Part 54 criteria, it's those SSC's that are safety related, non-safety related which can affect safety related, and those that are related to five regulated events, which include fire protection,

EQ, PTS, anticipated atlas, and station blackout.

With regards to safety related, the safety-related definitions in Part 54 is the same as in our current procedures and quality instructions. We used the SAR, tech specs, our licensing correspondence, DBD's, our component database, and design drawings to establish which systems and structures were safety related. And I think this is an important point, we even looked at all non-safety related systems and structures to confirm there were no components in those systems that were classified safety related as part of a validation that we had captured.

With regards to non-safety which can affect safety, which is probably the most difficult portion of the scoping effort, we used SAR, tech specs, and licensing correspondence, DBD's, our component database, design drawings, and pipe stress analyses. This was really to establish how much of the pipe is in the seismic analysis because, up front, we did include that piece of pipe.

We see two categories. One that actually provides functional support. In other words, it needs to run in order for the safety system to work. And the other is one where the non-safety system could

actually, through failures, could actually affect the safety-related component.

In the regulated events, we used, again, the SAR, tech specs, licensing correspondence, DBD's, component --

MEMBER LEITCH: Steve, just back on that previous one where you were talking about potential interactions. Was that done by physically walking down and looking at the configuration of some of this equipment?

MR. HALE: It does. The approach we took to II over I was an area-based approach, and, right up front, we included all the non-safety related supports. If we had an area where there was non-safety and safety-related equipment, we basically included all the supports, all the conduit that was non-safety related. The only thing we didn't include was the pipe because, from a design-basis standpoint, our pipe was never classified that way. So we were trying to do it consistent.

Now, there were portions of pipe as part of the Unit 2 licensing basis that was specifically designated as seismic in our licensing basis, but the basis for both Unit 1 and Unit 2 was not so much non-safety which can affect safety, it was from a seismic

event as an event whether you could shut down the plant. So you may have certain components that don't come into play in shutting down the plant, whereas they would be in play, like the hot-pressure safety injection pumps during an accident. So the design bases were different. We tried to clarify that in our II over I response.

But we understand what the staff's concern is, and we evaluated it based on the Interim Staff Guidance that was issued and what we had done for Turkey Point.

MEMBER LEITCH: Again, I'm still a little confused. Was most of this work done by reviewing documents, or was --

MR. HALE: No, we actually did field walk-downs. We went out and walked down the plant. We identified every non-safety related system in safety related areas. We physically walked down and looked at it. And again, like I said, one of the inspectors who came in for the scoping and screening inspections actually went and, you know, looked at what we had done and actually went into some of these areas to actually see what we've inspected.

MEMBER LEITCH: Okay, thanks.

MR. HALE: Yes. There was quite a bit of

field work involved with it. I guess from the II over I standpoint, there was other things we had to look at. We had to look at flooding. We had to look at, you know, a wide range of other type of events outside of the seismic interaction.

MEMBER ROSEN: Steve, you mentioned that you marked the drawings to show components that were now in license renewal scope; am I correct?

MR. HALE: Right.

MEMBER ROSEN: Which drawings did you mark when you're talking about these non-safety related systems which can affect safety related? Just marking PNID's would seem not adequate to me.

MR. HALE: We actually had to draw a wall, so we actually put some spatial lines on the drawings that says "in the P-pump room" or, you know, that sort of thing.

MEMBER ROSEN: So you had to augment the existing PNID's?

MR. HALE: Exactly, exactly.

MEMBER ROSEN: If you're using just PNID's to do that because they don't really represent the lengths of pipe.

MR. HALE: Right.

MEMBER ROSEN: I mean, they're

abstractions for the reality that's out in the plant.

MR. HALE: Yes, that's true. And that's a good point because we ran into that issue when we actually started to go down and physically designate. In some cases, it was between valves, but, in other cases, we actually had to draw, you know, like, for example, at St. Lucie, we have a room which has got some swinging switch gear on the 19-5 level, and we actually drew a wall that says "non-safety related pipe in AB switch gear room," so that's actually marked on the drawings now.

MEMBER ROSEN: Okay. You've answered the question with respect to the PNID's. Did you go down to the next level of drawings, say the isometrics, and annotate them for what's in storage?

MR. HALE: No, because when you really look at it, what it is that, when we look at our inspection, what really is the end point? The end point is, on some of this piping, you're going to do external visual inspections, okay, and you're going to monitor the piece of pipe that you're talking about. And the PNID's were adequate for that aging management program that you're doing. You really didn't need to go into the isometrics to do that.

If we felt we had to to appropriately

identify it to the people that are actually going to be doing the aging walk-downs and that sort of thing, then we would have. But we didn't find it necessary in what we were dealing with. Most of it was just straight runs of pipe in a room, you know, where we could draw boundaries at the walls.

Anymore questions on that area? I mean, when I first got involved with license renewal, I said, "You know, safety related and regulated events, that stuff is pretty well documented. You can access your CLB's. But when you get into this area of II over I, it's probably the most complicated." And it's an area that we need more details and guidance on how to approach it, and I think the ISG has really helped us, you know, focus on what it is we need to look at and how we need to approach it.

Okay. On the regulated events, there were some other documentation we utilized. We have a control document called the Appendix R Safe Shut-Down List. We also have an item called the Essential Equipment List; EQ List, which is derived right out of our component database, and we also have a Load List that we use to confirm that, in the St. Lucie Unit 1 case, where we credit the Unit 2 diesels that there's adequate power or that the diesel can accommodate a

blackout at one unit, as well as a loss of off-site power on the other unit.

Just a summary of the scoping of systems and structures. For St. Lucie, 39 out of 70 systems were in scope, and 16 out of the 46 structures on-site were in scope. We did include layout figure in Chapter Two or section 2.2, which shows the structures that are in scope on the site.

In screening, the purpose is to identify structures and components which require an aging management review. The criteria is what we call component-level scoping. Once you've identified the entire structures in the scope, then you go down to the structure systems in the scope, you go down to the component level, and then you do your screening or you look at whether it's passive or not and whether it's long-lived or not.

In the mechanical area, we established evaluation boundaries and interfaces with other systems so that we made sure we captured everything. We identified the specific structures and components that were included in the systems evaluation boundaries. We looked at the intended functions, and then we identified which ones supported those functions from a passive standpoint. We also

evaluated them, whether they were long-lived. And in this area, we actually got into plant procedures and that sort of thing. There had to be specific references if things were replaced based on a specific life that would be documented in our technical documents.

MEMBER LEITCH: Can I ask a little bit about that passive classification? I guess I'm beginning to develop a little concern about electronic components, power supplies, and things of that nature. And some of this may be, you know, beyond the scope of the rule, but I'm just wondering, I think, by nature, you've classified electronic components as active, generally, and, therefore, they fall out of the screening process.

What I'm beginning to notice as I review operating experience that there seems to be a growing trend of plant upset condition, Scrams, so forth -- I'm not necessarily talking St. Lucie, I'm talking about the industry in general -- that are the result of failed electronic components. And I'm just beginning to come to the conclusion that, perhaps, generally, as plants approach the age that they're approaching now, that we're going to have some failures in electronic components.

Now, some of these are active in a sense that the failure can be detected by maintenance procedures, surveillance tests. You do a surveillance test, and you find a component that's failed. Some of them are revealed by a half-scram or one channel of logic, but some of them are revealed in a kind of unfortunate way. They scram the plant, or they close some other kind of upset conditions.

I guess I'm just wondering do you have, independent of license renewal, is there some kind of a program to assess which electronic components whose failure could, all by itself, cause an undesirable chain of events.

MR. HALE: Yes, and I think, you know, that that's a perception that I have to put on when I think is that, just because it doesn't get included as an aging management review for license renewal doesn't mean we're ignoring it or we're not addressing it. One of the bases in the revisions of the rule, which was in the 95 - 96 timeframe, was that we do have a lot of programs that look at active components, plus surveillance, tech specs, and the fact that that stuff does get bubbled up in operating experiences is one indicator that this stuff is being looked at and watched and actions are being taken.

I can't speak for other utilities, but we have breaker programs, you know, where we have a set preventative maintenance where we go into all of our breakers, which are an active component, but, you know, they get a lot of attention. Certainly, all of our instrumentation that is covered by tech specs gets tested regularly. You have surveillance testing, this sort of thing. Then, as certain issues arise, like Agastat relays that are energized, you know, all the time, we had to start replacing those like every three years. You know, those sort of things. But a lot of the reason why we don't address the active stuff and license renewal is because it's an overlap of everything we're already doing in that area. So, you know, I've tried to communicate that, as well, to the people I talk to just because it's not in license renewal aging management review doesn't mean that there aren't programs out there that are addressing it and, in specific, looking ahead.

We also have some strategic plans looking at obsolescence of instrumentations and controls at St. Lucie and Turkey Point, you know, in terms of long-term, looking at what's called lifecycle management, looking at instruments that you no longer have spare parts for. There's quite a bit of activity

right now in our utility looking at those active electronic components. So I give you assurance that we're paying attention to it.

And if you look at maintenance rule, for example, it carries trips, you know, PRA; there's a number of other components that are included in the maintenance rule monitoring specifically related to some of those active components and systems.

MR. KUO: And Dr. Leitch, if I may interject really just a brief background to offer the true rules. In 1991, we had one rule, and we had also demonstration project that we using as the example. At that time, we did include the active and passive components, and that was one of the lessons we learned from '91 is that, gee, after we reviewed all this, it appears that all the components, they have programs to deal with if they're ready. There's really no need for us to have any additional aging management program for that, and this was based on the conclusion also from the prior program, the new aging research program. We had about 150 research reports on that.

So as part of the lessons learned, we advised the rule in 1995. It was published in December of 1995, and also, at that time, we had established the maintenance rule, which is the basic

focus mostly on the active components. Later on, the passive components were included.

But because of all these background information, that was how we revised the 1995 rule. We do have a sufficient activities there to make sure that active components are being taken care of, and what we really are not too sure about are those passive components.

MEMBER LEITCH: Okay, thank you.

CHAIRMAN BONACA: Well, on the same length, since we are interrupting with questions, I would like to ask another question on this. I was reviewing the pressurizer spray, and there you have a screening process by which you conclude that the pressurizer spray head should not be in scope. And the reason was that the function of the spray head is the one of, essentially, enhancing the efficiency of the spray. And you went through an elaborate demonstration of why you're going to need to do that. You can survive an event where you need to spray the pressurizer for protection purposes, but you can do without the enhanced effect of the spray head. When I look at the kind of discussion that takes a number of pages here and there, I'm left with an impression that we were on this plant maybe with

components, like a spray head, that would fail before anything is done to it. And I'm sure that's not the way you want to run the plant. So I'm trying to understand the logic. I mean, these discussions are not only about the pressurizer spray head; there are other examples of that. Do you have any inspection of the spray head ever done, or is it part of -- I was left to the question, you know, are they ever going to look at the spray head, given that you have a component which is subjected to significant thermal cycle and, therefore, I'm not sure it's going to break without cracking for 60 years.

MR. HALE: Well, to give you some history on this, we took the position that the Westinghouse Owner Group originally took in their topical. We used that position at Turkey Point. The aging effect is thermal embrittlement of stainless, it's not the fatigue issue. And there's some question as to what that real effect would be, you know, whether you'd really see that effect in the spray head. You know, there's not a lot of data on extended, you know, usage, that sort of thing.

Our feeling, from an aging management standpoint, is not that this thing was going to fail. One, we had a technical argument why it should be in

scope from a functional standpoint. I mean, I look at our challenges, as an engineering organization, and the rule is very prescriptive in terms of what's required to be in scope, what isn't. So we go through that process, and our conclusions were it in weren't in scope. I think my own opinion is that we probably are not going to see anything with the spray head. If we ever do go into pressurizer for any reason, we'd probably look at the spray head; we would probably recommend that. But do we have to? Our feeling is we don't. And, you know, there's a lot of those to say that we have to do that means we've got to open the pressurizer, we've got to, you know, subject folks to dose and that sort of thing.

But we also got to look at the failure. If it does crack, what does that mean? Okay. It's not going to affect your safety functions, okay, but you may lose some efficiency and control. Is that something we want to happen? Certainly not.

I don't know if I answered your question, but the main reason is we have taken that position at Turkey Point. We utilized the same position at St. Lucie. There were some additional questions that were raised. We tried to demonstrate why we came to the conclusion we did.

CHAIRMAN BONACA: Thank you.

MR. HALE: In the civil area, I went for the next slide there.

MEMBER WALLIS: What does long-lived mean?

MR. HALE: Long-lived means it's not replaced on a regular sequence or schedule. In other words, we assume stuff was long-lived if we didn't have specific --

MEMBER WALLIS: So no life is specified?

MR. HALE: Right, right. What we required of our engineers when they were doing their evaluation, there had to be specific maintenance procedures that require replacement of these components regularly before we would take that position. So, you know, we just couldn't say, "Well, we think we replaced that periodically." There had to be specific references that were quoted. A good example is filters on HVAC equipment, like in your house or things you might have on motors. You know, we have a set frequency. We replaced those every 30 days or whatever the frequency might be. There could be a specific maintenance procedure that calls for doing it.

MEMBER WALLIS: It's not the 30 days, but it's when you get up to 10 years or something, then

it's sort of a fuzzy area.

MR. HALE: Around 40 years is the criteria. If it's not replaced on a frequency that's less than 40 years, then it has to be included as a long-lived item.

In the civil area, it's pretty much the same approach. But in this case, you've got the electrical all inside, when you get into the civil structural area, almost everything is in scope because it's all passive, you know? So maybe that offsets the electrical piece.

CHAIRMAN BONACA: I'm sorry. Just to close the issue of pressurizer, you're going to inspect, however, the thermal sleeves of the pressurizer header, right?

MR. HALE: No.

CHAIRMAN BONACA: Or the spray header. No?

MR. HALE: No, no. If you will look in that, the pressurizer sleeves are not welded. The issue there was whether the sleeve would, correct me if I'm wrong, Tony --

CHAIRMAN BONACA: That was the weld.

MR. HALE: Yes, welded. It's actually expanded, pressed into the nozzle itself.

CHAIRMAN BONACA: I see. And so --

MR. HALE: So it's no connection to the pressure boundary.

CHAIRMAN BONACA: Okay. So you would not look at it?

MR. MENOCAL: There would be no need to.

MR. HALE: We do look at, certainly, the welds associated with the nozzle itself.

CHAIRMAN BONACA: Okay.

MR. HALE: In the electrical and I&C area, as you mentioned, we do take a slightly different approach. This is more for efficiency of our review. We actually eliminate the active components up front because, again, you know, 95% of the electrical components are active. The example I give is the first time I did a component download on our 40-volt system at Turkey Point, I got 18,000 components. And to go through and say "active, active, active, active," it made more sense to eliminate the active categories up front and then deal with the passive components.

And again, the one point we want to make in the electrical area, if something was in the EQ program, it is replaced on a qualified life. So even though some of these components may be greater than 40 years, the fact that it is in the EQ program allowed

us to eliminate it as a long-lived item. This is consistent with what previous utilities have done.

As far as the screening results, the results are summarized in Chapter Two and then the details are presented in Chapter Three's six-column tables where we list all the specific components relative to each system structure. There are four mechanical sections: rack and cooling system, connective systems, ESF, auxiliary systems, and steam and power conversion. Next is the structural area and then the electrical area. We did cement license renewal boundary drawings to facilitate the NRC review of our application, and we also included a SAR on the CD that we submitted, which allows the reviewer to actually link to the specific SAR sections or link to the specific drawings on the CD that we had submitted.

Now I'd like to shift into the aging management review. This is a definition that's in the regulations, essentially, that we demonstrate that the effects of aging will be adequately managed, so the intended functions will be maintained consistent with the CLB for the extended period of operation.

How do we go about this? What I'd like to just communicate to you is that we had two areas. Aging effects requiring management were established

based on two primary areas: the AMR technical resources we had available to us and our operating experience reviews. The methodology we used for determining the aging effects requiring management for non-Class I in the civil and structural area is in Appendix C. This is an approach that was originally developed by the B&W owner's group. It was then adopted by the other SSS owner's group and has now been placed with EPRI, and so it's now a standardized tool for the industry to utilize.

As far as in the technical resources area, even though this is not a Westinghouse plant, there's a lot of good information that was developed in the Westinghouse generic technical report. I believe about five of those were submitted for NRC review. There's another 10 that were developed for us by utilities, we utilized those; The original NUMARC license renewal industry reports, I believe, late 80's, early 90's. Again, we mentioned B&W tools. We had a big database from the Turkey Point aging management reviews. We had a new document we utilized, which was the GALL report, and, in some cases, because we did have some unique materials at St. Lucie, we had to get into materials handbooks and in-house materials expertise. We do have

metallurgical folks on staff, and we do have a metallurgical lab.

MEMBER WALLIS: Steve, I'm sure it was a slip of your tongue, but when you sort of talk about the GALL report, you said you could have used. You did use?

MR. HALE: We did use it. I'm sorry, yes. It was issued during the St. Lucie development of our technical documents. Yes, we did use it.

And then, again, our participation in industry groups. I don't know if you were aware, but there are, like, three technical groups in addition to NEI, which is groupings of mechanical, civil, and electrical license renewal utility engineers, which meet periodically to discuss issues and how to address certain aspects of the reviews, as well as how you address aging and certain areas. So we were active participants in all three of those groups.

MEMBER ROSEN: Steve, I was interested in your comment that you have some unique materials at St. Lucie. Could you just expand on that on a bit?

MR. HALE: Yes. The Unit 1 RWT is aluminum. The one area that we found there was no industry information, I won't say materials, maybe some chemicals, was we have a sodium hydroxide tank

that isn't unique, but we couldn't find any information, so we had to go research on the aging effect of sodium hydroxide on stainless. Unit 2 has hydrazine. We're trying to look at data. You know, we're trying to go into a mechanical handbook looking for industry information on how that's done. But I guess RWT is really the unique component. It's aluminum. Unit 2's a stainless.

MEMBER FORD: Along that seems sort of the line of questioning, Steve, you're absolutely correct. All of those documents that you described are very useful resource. However, aging phenomenon fortunately change with time, as do materials.

What sort of license do you have or do you exercise on yourself to make use of the evolving knowledge that have accrued since those documents were published? For instance, 600 techniques, are they still valid since they were evolved in the mid 1990's and so on? What sort of license do you allow yourself to make use of the evolving knowledge?

MR. HALE: Well, on specific industry programs, like MRP, we're tied into MRP, which is the group that's looking at various material aspects in the reactor vessel internals area. We do participate on the number of industry groups. We do look at

operating experience on a regular basis. But in terms of getting out ahead and trying to be proactive, other than in the research area through EPRI, there really isn't a lot that we have that we can go to or draw on, I guess.

MEMBER FORD: Okay.

MR. HALE: But we do participate in industry groups. I think the industry, as a whole, tends to use EPRI for their R&D. We do have a number of metallurgists on staff. In fact, one metallurgist was involved directly. You know, when we get this B&W tools thing, then you need to apply it to your own site in terms of have we seen in this system or that system, what have seen metallurgically in terms of SEC in certain areas of the plant. We did try to gain that knowledge. We did draw on the industry in terms of potential aging effects, in terms of evaluating them. And then we had a lot of operating experience. But I would have to say, in terms of getting out ahead of things, our primary means is through industry groups and EPRI.

MEMBER FORD: Okay.

MR. HALE: We're pretty proud of our operating experience reviews. We did a fairly detailed and a long look backward in terms of what's

happened at our power plants. We did look at NPO and NRC generic communications and looked at, you know, what our responses were to all those documents. That's all captured in our technical documents, review of those.

We went back and looked at non-conformance and condition reports throughout the history of the plant. We looked at response team and license event reports. The event response team is something that's formed, like, if you have a plant trip or in some significant event where you need to evaluate that.

We went and looked at all of our metallurgical laboratory reports. When you get into some unique aging effects and things of that sort, we really don't know what the root cause was. They were evaluated in our metallurgical lab, you know, electron microscopes, things of this sort; and we factored the results of that into our aging management reviews. And then we had specific discussions with the system and component engineers at the plant, as well as specific walk-downs of the systems.

This review of operating experience is important in two aspects, I think. One is it helps you in identifying aging effects, which may come about, but it also established that we are managing

aging in our plants. We're looking at things, we're evaluating them, and we're correcting them.

MEMBER LEITCH: This may be a little in the environmental area, but when I look at event reports and I see one from St. Lucie, it seems like 90% of the ones I see from St. Lucie have to do with sea turtles. What's the story there with sea turtles?

MR. HALE: Well, the sea turtles --

MEMBER LEITCH: It's just a curiosity question.

MR. HALE: There are various sea turtles that are endangered species, and we're required by our consultations with the environmental, NMS, National Marine --

MEMBER FORD: Fisheries Services.

MR. HALE: Yes, I guess. And document that. In fact, we just invested close to a million dollars in a new turtle net. We've got an intake canal with a pipe that goes out to the ocean. We have a velocity cap on that to try and, you know, keep fish and that sort of thing from getting into the intake canal. But once it gets into the intake canal, if you have an endangered specie, you want to ensure that he stays healthy. And what we have is we have a net that comes up, and the turtles, you don't want them to

drown, basically, so we have a crew that's out there continually. In fact, the environmental league of my project actually went out and helped them pick up one that weighed about 800 pounds about three months ago.

MEMBER FORD: Really?

MR. HALE: But every time we capture one of those, you know, it needs to be reported.

MEMBER FORD: Then they're alive? I mean, even if they're --

MR. HALE: Yes. And then you have to establish, if they are injured, whether it was due to plant operation or he has, you know, some other illness or that sort of thing. And if one has been killed or is dead, they actually do autopsies to evaluate the cause of death. But we're limited to a certain percentage of the total intake as to, you know, mortalities if it's due to plant operation. That's why you see that, and you see it from Crystal River, too. They have a similar type of situation.

MEMBER LEITCH: You don't seem to notice it at Turkey Point; that's a different situation?

MR. HALE: Yes. We don't really get that kind of wildlife. In fact, it's actually reserved for the endangered crocodile at Turkey Point.

MEMBER LEITCH: I see.

MEMBER ROSEN: This question is not on turtles.

MR. HALE: Okay. Bruce knows all about it. He was responsible for the design of the turtle neck.

MEMBER ROSEN: Let's go back to the aluminum thing --

MR. HALE: Okay.

MEMBER ROSEN: -- the fueling storage thing in Unit 1. You switched to stainless steel for Unit 2?

MR. HALE: Yes.

MEMBER ROSEN: Was that because of unsatisfactory performance in Unit 1's aluminum tank?

MR. HALE: No, I believe it was a more standard material. We have had issues with the aluminum tank, but I don't think that was the reason for the decision.

MEMBER ROSEN: What sort of metallurgical issues were there in one tank, and can we have confidence in it that it will last for 60 years?

MR. HALE: Yes, yes. And we actually have a program, as part of Section 11, to go in and inspect that tank regularly. We have, like an epoxy coating on the bottom that has to be inspected, and we

identified that in the application. It requires inspection.

MEMBER FORD: Steve, I think you and I have got kind of a pit team going here because that particular incidents on the aluminum tank corrosion and its relationship to galvanic corrosion came up with a question I had. Maybe it's out of order, but you might as well take it now.

Your galvanic-aging program makes the case for one-time inspection of various structures, and it's based on some algorithm, which quite rightfully, takes into galvanic series and etcetera, etcetera. Has that algorithm been tested against observation, and could it have predicted this particular instance of galvanic corrosion of this aluminum source tank?

MR. HALE: But the thing we need to clarify on our galvanic program is our galvanic program is for areas where we have dissimilar metals in treated water systems. I want to clarify that. That's why that's a one-time inspection. We don't anticipate finding galvanic corrosion in the areas that we've identified as part of the galvanic corrosion program. When we have areas where we know we get galvanic corrosion, that's loss of material, when we say we have lost some material, because you

get loss of material for other reasons, as well. So that's why the galvanic is more geared to a case where you might have a stainless and carbon and a chemistry-control system. There's not a lot of industry data on whether you get any galvanic corrosion in that kind of a case because, you know, you also need the electrolyte and other aspects of it. So we prioritize, and we identified every galvanic couple in the plant.

Now, with regards to this particular instance, I think we've had operating experience, we have seen it, we did not have an active -- I mean, in this case, we had a galvanic, like insulating flanges and that sort of thing, to protect against it because we knew we would get it, but, unfortunately, there were some problems with that couple, such that we got the galvanic and we were designed not to get it. In other words, we didn't have the insulating flanges attached properly, and we actually got -- go ahead, Tony, you can probably --

MR. MENOCAL: I'd like to just clarify. The galvanic corrosion that we had in the fueling water tank for Unit 1 was tank bottom, Steve. We do have a galvanic couple on one of the lines coming in, but I believe it was due to external actual galvanic corrosion, something that was in the fill that

actually produced a corrosion cell on the tank bottom.

MR. HALE: You're right.

MR. MENOCAL: And possibly internal, as well. But the corrective action was installation of a liner. But I think the point Steve is trying to make is that where we know we have had, where our tools tell us we have potential for galvanic corrosion, certainly, we would credit a program for doing that. And it may not be, it could be intake cooling water, inspection program, system inspection program. It could be a different system searches monitoring program; it could be a different program.

MR. HALE: For example, the salt water system, we don't credit the galvanic corrosion program because we're going to get loss of material from a wide range, including galvanic, so that's included with the loss of material.

MR. MENOCAL: But the galvanic corrosion program is for those cases where, merely, the metallurgical tools we had to determine whether we have any significant corrosion rate due to galvanic or not is really we don't anticipate it. We didn't feel we had enough confidence to rule it out, even though we had no operating experience to show that we had it. So it's more a confirmatory program to make sure that,

even though we don't feel we have it, that we've actually physically inspected and confirmed that.

MR. HALE: And that's to address your question on the one-time inspection. Now let's get back to --

MEMBER FORD: Yes, I didn't want to get into the details of this particular incident. It's really kind of a longstanding concern I think many of us have had about what is the rationale for one-time inspections? The experimental, the validity of prediction algorithms say we should inspect this one time. Where is evidence that this methodology is quantitatively correct? Because it's supremely important to me. If you want to have one inspection to go from 40 to 60 years, that inspection better be at the right place at the right time.

MR. HALE: Right.

MEMBER FORD: And I'm just trying to follow along that line. Maybe you can go into some of the open items I know. Maybe you can discuss that at that time.

MR. HALE: Well, the one-time inspection, the way we applied it, what our logic was, one-time inspections are those associated where we don't expect to find aging effects, okay? So I want to make that

clear. That's an area that we would not apply one-time inspection unless we don't expect to find aging effects.

Now, though we have, in our corrective actions, is if we do find aging effects, then part of the corrective action may be to require additional inspections. So you'll find that embodied in our inspection approaches. And I can tell you, you know, because we're in the implementation stage at Turkey Point, for the galvanic, we did a detailed evaluation of material deltas. What were the three criteria that you used, Tony, in developing the spec? And there were multiple locations --

MR. MENOCAL: Yes. What we're doing is we're just trying to limit, since you have hundreds of sites, what we do is systematically identify the most limiting locations based on, again, as you mentioned, the galvanic series, the electrolyte, the contact area between the anodic and cathodic materials. We basically go through and address all those attributes, and then we prioritize so that, what we're inspecting, we have great confidence that it's a limiting and bounding location for all those other areas. And we also try to make sure we address all the different environments as part of that process to make sure that

we've got all of the bases covered.

MEMBER FORD: I'm sorry for taking up time here, Mario. I think it's an important issue. You said a good word there: bounding condition. Therefore, make sure that your decision algorithm is correct. You must go beyond that bound. You must take into account areas which have corrosion, have undergone the galvanic corrosion, and that's why I asked the question about this particular aluminum tank. Did your algorithm predict that that would have failed? Therefore, your bounding condition has been validated. Do you understand what I'm getting at?

MR. HALE: Right. I understand what you're saying. I think because of an operational issue, I'm not sure a galvanic program would identify this. This was an issue between, as Tony was saying, I guess the fill in aluminum tanks.

MR. MENOCAL: Yes, I don't remember now whether it was an external material that was either in the bottom of the tank or external. That's what I don't recall specifically, but I know it was, you know, the couple was created because the location where you would not have expected it. Obviously, we have grade-one fill in the tank bottoms, and you would not have expected something to be there either

internally or externally.

MEMBER FORD: I've made my point.

MEMBER ROSEN: Well, I need to summarize a little bit. What I understand from this discussion is that you have an aluminum refueling water storage tank in Unit 1, which has experienced galvanic corrosion on the bottom, either external or internal, I'm not sure which, external. And that you have an aging management program to assure yourselves that this tank will serve its functional requirements through the extended period of operation.

MR. HALE: Right. And we had to do that as part of our ASME Section III program. It's actually an ASME required inspection now. In fact, we flagged the coating material in the application as a requiring program, and we identified aging effects associated with it.

CHAIRMAN BONACA: I have a question. I don't understand how you apply it. For example, I was looking at the intake cooling water inspection, and, there, you have a lot of small piping that corroded in the past 20 years, and you replaced 75% of it.

MR. HALE: Right.

CHAIRMAN BONACA: So you still have 25% of the original material that you now replaced with a

corrosion-resistant material. Now, in the application, you made the case, and the NRC accepted it, that all you have to inspect now in the future is the connections between the small-bore piping and the large-bore piping. I'm left with the question, you know, a priori or operating experience will tell me that I should inspect, also, the other 25% that I have not replaced. How did you come to the conclusion, from your operating experience, that you don't have to look at it.

MR. HALE: Well, we didn't. That's not the conclusion. What we came to is that we could utilize leakage inspection as an adequate aging management program for those nozzles. Our problem is we can't get inside of that pipe. These are small-bore pipes. We can look at the connection, and that, typically, will be worst case. We're using a combination of the crawl-through inspections that we do in looking at this, in addition to periodic leakage inspections externally. And our basis for saying why leakage inspections is acceptable is that it's an open-cooling water system, and we have margin. As a result of our operating experience, where we've gone through replacing these, when we do get a leak, it's not catastrophic. We get a small leak. It will not

impact. In fact, we factor in, I believe it's 100 GPM of loss flow, plus another three-quarter inch break, as part of our verification that we can meet our design standards.

It's not that we're not looking at them. The case we were building is that leakage inspections is acceptable for this open cooling water system.

One of the things I thought we would do is go through what we did with GALL. This was a specific request from Chris Grimes that we do this since the GALL was formally issued, and we tried to accommodate, as best we could, considering where we were in the development of our technical documents.

If you'll go to the next slide. Uh-oh, what happened here? Oh, I thought I saw GALL up there. That was my fault. Okay. Why don't we go back and make sure that I covered everything. Okay, go to the next one. We're okay.

Okay. In Chapter Three, we grouped components the same way they were presented in Chapter Two. The results are presented in six-column tables. These are consistent with what we had done with Turkey Point. Our basis for the aging effects for the non-Class I are described in Appendix C. And in terms of electrical design features, our medium and high-

voltage cable is ledge-sheathed, and we have a lot of outdoor areas in our plant, as opposed to most plants that you look at.

Now, for the GALL comparisons. We flagged differences between the component listing in GALL versus our component listing. This was really to avoid or not to get into RAI's related to why isn't, you know, extraction seen in the scope because it's in GALL. So we specifically, in each section, we summarized, you know, any components that were in GALL that weren't in our plant, as well as components we had that weren't in GALL.

We also tried to flag, generally, what the differences in materials in internal and external environments. And then we did provide a reference in the six-column table. This was just for information. Where ever we got a match between the component, the material, and the environment. So if you got a match on those three, we provided a GALL reference. That just was for information for the staff.

And then probably the biggest aspect of GALL that we utilized, if we could get a good match between our program and what was described in GALL, we took credit for GALL if we had a program that was consistent with it.

And this just shows you some examples right out of the application. This is, you know, a summary which shows how we address the deltas between the components in GALL versus our own plant. The next one talks about, you know, how we showed the differences in materials and environments. You know, with regards to GALL, we identified hey, we've got some, you know, like here's the aluminum. We have fiberglass. You know, there were certain things that weren't in GALL that we have from a materials aspect.

This is just a sample of the six-column tables. What I was just going to show you here, you know, here's a case where the safety injection tanks were stainless steel. We got a match with GALL, so we provided the GALL reference right there so staff could go to that table and see how we compared with GALL.

And then, at the end, we summarized those programs we credited in this particular section that were consistent with GALL, and then we also identified the plant-specific programs.

With regards to Appendix C, this, again, was something that we found useful at Turkey Point. The intent here really is any area where you have taken a generic position on aging effects, you know, so you don't go through repeat RAI's at various

sections that you have a technical basis for why, you know, that position was taken. We did factor in some of our RAI's and RAI responses from Turkey Point into this section. And in other lessons learned, we pared it down and didn't put as much information as we had before because some of the information has actually caused some confusion in the Turkey Point application.

Some of the specific generic discussions with regards to SCC, bolting, high-cycle fatigue, those were some of the items that were addressed here for non-Class I. Again, the RAI's and, again, as we mentioned previously, we followed the EPRI tools and adapted it to St. Lucie.

What I'd like to do right now since there was a question raised about phosphates and how they affect concrete, Bruce is going to kind of go through that to talk about that, and then he'll turn it back over to me. So Bruce Beisler, our civil lead.

MR. BEISLER: Yes, as Steve said, Bruce Beisler, civil, from FPL.

Basically, the staff asked us to address two questions regarding concrete, specifically the concrete below ground water. One had to do with phosphates and how that affects the concrete, and the second one has to do with corrosion of rebar and how

that is managed.

Tending to the first question on phosphates, during our license renewal process, we had not come across any issues associated with the phosphates in the soil or the ground water affecting our buried concrete, so we said, well, let's go back and take a look at the technical documentation and see if we can find any information regarding phosphates in the technical references.

So what I've included on this slide is a list of documents that we went back and took a specific look at just for phosphates, and you can see there we looked at the ACI documents. This isn't even the complete list. This is just what I chose to put on the slide because I think that these are the most likely places where we would have found information. ACI 201 was the Guide to Durable Concrete, 318 the actual building code, 349 the evaluation relating to nuclear plants, and 515 is actually an ACI document regarding water-proofing of below-grade concrete. And it's interesting to note, in this particular ACI document, there is a table, it's table 252, which lists several hundred chemicals and how those chemicals actually affect concrete. Phosphates, as a general topic, was not listed in that table. The only

reference was to phosphoric acid, and that reference really only pertained in relation to building a plant where you are processing food products, say like soft drinks, which use phosphoric acid in making the soft drink and how that could affect the concrete. And basically, what it tells you is contact the Food and Drug Administration for appropriate coatings to put on the flow, so that you're not affecting your concrete with your food processing.

But in general, there was no limitations on phosphates in the ACI documents that we reviewed. In addition, in the next slide, we looked at the ASME Section III requirements for concrete reactor vessels and containments and found no information there on phosphates. We looked at ASTM standards for the constituent materials for the concrete, the cement, the aggregates, and found no limitations even on phosphates in the constituent materials.

We also looked at the EPRI documents that really were involved with license renewal to see if there was any aging effects identified due to phosphates in those documents, and there was none.

So having exhausted the technical documents that we had, we contacted one of the Ph.D's at one of our large AE's that we utilize, and we asked

the question, you know, why can we find no information in the technical documents regarding how they affect concrete, and he was kind enough to do some quick research for us and kind of gave us a quick write-up on what he was able to find.

And he basically told us that phosphates are not very soluble in water in all ranges of pH, which is contrary to what you find with chlorides and sulfates, which are the main culprits in concrete degradation. Those are very soluble, so they are able to penetrate into the concrete, especially lesser-grade concretes and cause degradation.

Additionally, he told us that typical ranges of phosphates and soil or ground water in the neighborhood of 500 to a thousand PPM total phosphates, but most of that is fixed, meaning that it cannot be transported to the concrete to cause the degradation.

Nearly all the water soluble phosphates are converted to non-soluble shortly after, if they do come into contact with the concrete, shortly after they do come into the concrete, so they're not able to penetrate into the concrete. Of course, the phosphates, in general, are not harmful to the rebar. If there was any effect, it would affect the high

alkalinity of concrete. So his conclusion, based on his research that he did, was in support of what the industry technical documents really tell you is that the phosphates are not a contributor to degradation of concrete.

One thing I'd like to point out is that, for St. Lucie plant, specifically, we recognize from the very beginning that our ground water was aggressive. Our chlorides are higher than the thresholds, the published thresholds. Our sulfates are higher than the published thresholds, so we recognize that we needed to manage our concrete below ground water from the very beginning, and that's in our application specifically. So we don't feel that, really, the phosphates are even a factor for St. Lucie, but we did want to address the topic generically.

And just as a point of reference, you know, in our initial work for St. Lucie, we did ground water analysis, which is documented in our FSAR, and there was no information about phosphates in that list of all the different chemicals that were analyzed. So we specifically went out and had a lab, took a sample of our ground water and had it analyzed, and our ground water actually had less than one part per

million of phosphate content. I don't know how significant that is, but that is a fact.

MEMBER ROSEN: One of our other members, one of those who is not here right now, Dana Powers, who had concerns about that. Has this summary been provided to Dana?

MR. KUO: We had made a presentation to both Dr. Powers and Dr. Ford a month ago, I believe, and, at that time, I didn't hear any more questions from either Dr. Ford or Dr. Powers.

MEMBER FORD: Well, my personal concern is for the rebar. Dr. Powers' comments, I think I remember, were related to some observations that he had had of phosphates affecting concrete fragility, etcetera. Obviously, he has not seen this particular compendium of things I think he should see.

MR. KUO: At the time when we made the presentation to both of you, we didn't have the content of phosphate at the St. Lucie. So that was one request that was made. For this subcommittee meeting, we need to address that and see if phosphate content --

MEMBER FORD: And that's very appropriate. I just think that Dr. Powers should see this.

MEMBER ROSEN: Maybe we can make sure the

staff, our staff gets the material then.

MR. KOBETZ: The paper that the Ph.D. prepared for you, is that something that we could get a copy of and prepare --

MR. BEISLER: Well, it's not a published paper, so it's just something that he kind of threw together very quickly for us, did some quick research, and actually contacted some university professors to get some input for the document.

MR. KOBETZ: Okay. You may consider trying to provide something prior to the full committee meeting. It might shorten up discussions in this area.

MR. HALE: I think one point, when I saw this question, was I don't think it becomes an issue unless you're trying to show that your water is not aggressive. You know what I mean? Or the discussion. In our case, you know, we knew immediately that we had aggressive ground water, so the need for sampling and this sort of thing, you know, we knew we were going to have to address aging effects. Whereas, if you're taking the position where you're relying on chemistry to establish that you have non-aggressive ground water, then I can where this question would be at issue.

MEMBER FORD: It just puzzles me that Dr. Powers has some very -- we're speaking for him in absence -- had some very positive viewpoints on the affect of phosphates on degradation of concrete, per se. It just puzzles me that we now have a long list of references saying, hey, there's no reference to it. There's nothing, say, a graph, a cut-off point between fragility and phosphate concentration.

On the rebar, this is the one I've been interested in, I was at an ACI meeting a couple of weeks ago. I very specifically went to the concrete corrosion, rebar corrosion, which was authored by somebody at the University of Florida, so I'm going to be interested to see what you say about this.

MR. BEISLER: Okay. Well, we haven't reviewed that document, but I'll tell you what we did find.

MR. KUO: If I may say something else, I believe when we talked to Dr. Powers, I think he agreed that this, in general, phosphate is not a concern. However, his concern is really to states, Texas and in Florida, where the weather chemistry contains a high percentage of a phosphate. I believe the applicant did that. You just said the phosphate content is one in a million?

MR. HALE: 0.15.

MR. KUO: 0.15? Okay. So that is actually, I think, is outside the range. You later on will hear staff's presentation, but that's, in general, I think -- and like Steve just mentioned that, you know, if we rely on water chemistry for concrete underground with ground water presented, then I think that would be a concern. However, they do recognize that their water is aggressive nature, and they provided an aging management program.

MR. BEISLER: All right. With regard to the question about corrosion of rebar, the first thing we looked at is, really, how can you protect your rebar, and that is with high-quality concrete. So we looked at the ACI documents and what they recommend for concrete in this environment, and what I've included on this slide is some of the facts. Basically, the ACI 201 for durability of concrete recommends a water/cement ratio less than 0.45, and St. Lucie structures their exposed to ground water, all specified, less than or equal or 0.44.

The ACI document recommends the ASTM C150 type five cement. In the case of St. Lucie, this cement was adopted by the ACI in 1977, and, of course, the St. Lucie specification for concrete pre-dates

that timeframe. And what we did use was the type two cement, which was the preferred cement at that time for sulfate resistance. Also, the ACI document recommends that we use an appropriate air entrapment, and for St. Lucie, the range of air entrapment was two and a half to nine-percent, and that's basically based on what size aggregate is used in the concrete. But all of that meets the recommendations of the ACI document.

In addition, the ACI document recommends moist curing for seven days, and St. Lucie required seven to 14 days, so we met or exceeded that requirement.

In addition, the ACI document recommends high-quality constituent materials, including aggregates per the ASTM C33, cement, ASTM C150, and very clean water, and all those are included in the St. Lucie concrete.

In addition, the ACI document recommends one and a half or, preferably, two inches of concrete cover. St. Lucie structures all have a minimum of three inches, and, in fact, the structures that are exposed to ground water have even more cover, in some cases up to five or six inches of cover, which is specified on the individual drawings for the specific

structures.

Concrete exposed to salt water should have a 28-day strength of, at least, 5,000 PSI. For St. Lucie Unit 1, the specification required 4,000 PSI, but the actual strengths of the concrete breaks, in general, were all over 5,000 PSI. So even though specification may have only required four, the actual concrete strength was greater.

In addition, the code --

MEMBER ROSEN: Is that a universal statement? You said "all."

MR. BEISLER: Well, all that we could find, but we're not certain that we could find every single concrete break, so I can't say that there wasn't one that might have been less than 5,000. But in general, and even our FSAR has that statement, the breaks were greater than 5,000. But personally, I didn't go and pull all the break records to confirm that it is 100%, so I can't say "all," I cannot say "all."

MEMBER ROSEN: In general, you said.

MR. BEISLER: In general, yes. And that's pretty typical, quite frankly, because the ACI codes have certain requirements, probabilistic requirements that, you know, if your specification is 4,000, that

you're going to exceed that 4,000 to reduce the probability that you could have one that would be less than 4,000. Commercially, that's done, as well.

MEMBER FORD: Everything you've mentioned is good news so far, but one item that concerns me the cover of the steel one and a half to two inches. Now, when I looked up at Turkey Point, I looked up on the containment, and I saw big bolts with knots on them, and I asked the tour guide, and they said, "Oh, those are the pre-stressing wise." Now, they seem to me to be exposed. The steel will be intention 5,000 PSI or whatever the equivalent would be. Is that pre-stress? In that particular instance, when I was looking up at the containment building, was, in fact, that the pre-stressed --

MR. HALE: Yes.

MEMBER FORD: -- and was it exposed to the environment?

MR. BEISLER: Well, the pre-stress wire, basically, what you have is you have the wire that's in the sheath, which is contained inside of grease, which is a corrosion-protecting grease, okay? And then at the two ends of the pre-tension cable, you have the anchors, and the anchors are the steel that connects and, basically, places that intention. Those

are exposed to the atmosphere, but they are painted, okay? The steel is painted for protection, and then you have, basically, the end of the pre-stressing material.

MEMBER FORD: Now, am I making too much of this? Now we're relying on just the paint over the nuts?

MR. HALE: No, no, there's a whole program, there's a whole program associated with the tensioning. And there are no, correct me if I'm wrong, Bruce, but there are no tendons exposed to ground water.

MR. BEISLER: That's correct.

MEMBER FORD: Okay. In the interest of time, I think we can move on.

MR. HALE: Yes, I apologize for taking so long.

MR. BEISLER: No, no, no.

MEMBER FORD: Unless the other members want to keep going on this concrete business, I'll probably bring it up in the open questions because it was opened in one of the opening questions.

MR. HALE: Well, one thing Bruce did want to summarize is what we have seen and what we actually do as part of the program.

MR. BEISLER: The program does include visual inspections of exposed interior and exterior surfaces of the concrete, and we look for signs of degradations, specifically corrosion of the rebar, in which case you would see cracking, rust staining possibly, and spalling, although, usually, it never gets to that point.

For our buried concrete structures, our program now includes doing inspections of buried structures, which are excavated for whatever reason. And although it wasn't part of the formalized program at the time it happened, we have done that in recent years, and I just cited a few examples here of situations where we did do excavations, we did inspect the concrete, and we saw no signs of degradation. And those are listed on the slide.

MEMBER ROSEN: What is the 2002 CPS replacement mean?

MR. BEISLER: That's cathodic protection system, and, basically, what happens is the anodes, after a certain period of time, are exhausted, and we had to install new anodes, in which case we did excavations adjacent to the structure, which allowed us to see varied portions of the structure.

MR. HALE: And again, I apologize for

taking too long. I know I've taken more than my allotted time here, so I'll try to get through the rest of what I have here.

With regards to the aging management program, for each aging effect requiring management, we identified aging management programs, and we did that on a component basis in the six-column tables. When you get into Appendix B, we provided the 10-attribute evaluations for the plant-specific programs, and then, for those programs, where we specifically indicated we were consistent with GALL, we discussed operating experience and demonstration, and we also had a brief description and a statement indicating that we were consistent with GALL.

Supporting that is an evaluation on-site which goes through an assessment of the GALL attributes versus our own program attributes, as well as the general program description and the criteria for the program. Those are documented in what we call our program basis documents on-site.

With regards to the application, we had presented the quality-assurance requirements, which we committed to be consistent with the staff on quality-assurance requirements. We included that in Appendix B in section II.

We had two categories of aging management programs. Our numbers may be slightly different than what's with the NRC because of the way we broke down the chemistry program. But essentially, we had 16 existing programs. We were able to show that nine of those were consistent with GALL, and then we have seven plant-specific. And in the new category, we had one GALL, and the other six were plant-specific.

This is just a summary of the existing aging management programs which were consistent with GALL. Section XI, all three, you know, the mechanical areas and in the structural areas: the Borflex surveillance program; our boric acid waste and surveillance program, although we do include more systems than were in GALL, in other words it's more extensive. We were able to show it was consistent.

Here's where we might see the difference in the way the NRC, the staff will present the chemistry program. We called it one program with subprograms, and they called them each individually a program. But we're able to show that two of our chemistry programs were consistent with GALL. This was in the primary side and the secondary side and closed cooling water. But just the way we structure our fuel oil chemistry program, you know, some aspects

of it, in terms of visual inspections and stuff, are covered by the PM program, and the chemistry is covered by other areas, so we weren't able to show that. So that is plant-specific. And our EQ program is consistent with GALL.

MEMBER LEITCH: Steve, I had a question about whether you're going to be able to fully comply with the new NRC order-related to vessel head penetration inspections. I know there's a plant that I think is similar to St. Lucie that is now having some difficulty fully complying with that order because of, as I understand it, rather than the more typical arrangement, this plant and St. Lucie also have guide sleeves or thermal sleeves in the CRDM penetrations, and that makes it difficult for them to get the required data. I just wondered if you've dealt with that problem yet? Are you going to be able to do those inspections?

MR. HALE: We have the guide sleeves on Unit I, and, in anticipation of that question, brought the 30-day inspection report that was issued after we did 100% visual -- it's documented. You can have it. What we found --

MEMBER LEITCH: This isn't enough for everybody to read.

MR. HALE: But that is our report that we submitted. We did 100% visual and 100% UT on Unit 1 last refueling outage, and that was the 30-day report to summarize that. There is a table in there that looks at UT inspections. If you look at the head penetration, we broke it into four areas. We have the penetration below the weld, what we call the weld area, the root, and then two inches above the weld. What we're able to do is we've got almost 100% coverage UT in the area above the weld and the root area. As you come out, our problem was one of there was too much slop in the thermal sleeve relative, so you couldn't get the -- the probe has to take two directional, you know, to insert it, it has to go this way and up in, and right at the bottom, you had a hard time getting the probe flat on the actual nozzle.

You'll see that in there, though, even in those areas where we couldn't get full coverage, we were still getting quite a large sampling of the information there. But it's all in that report, and I think you'll find it interesting.

MEMBER LEITCH: But this pre-dated the order, right?

MR. HALE: It did, it did, but it gets into details of the specific issue you're talking

about. Certainly, if we are required to do this, and we had two cases where we actually moved the sleeve. But I think what you get is how extensive the inspections were and how, you know, there was a pretty good coverage, although we couldn't get 100% in all areas, we did get a good coverage on all penetrations. And in the critical areas, we got almost 100%, which is the weld root and the two inches above. The justification for not full coverage there is, if you do get a crack, what you're concerned about, in terms of circumferential, you know, rod ejection, that sort of thing, is in that weld root area.

But that's all in the report, and I think you might find it interesting.

MEMBER ROSEN: I'm interested in what the overall results of the inspection were.

MR. HALE: We had no indication of leakage, and we had no indications of cracking on Unit 1.

MEMBER ROSEN: And Unit 2 is yet to be done?

MR. HALE: It's getting ready to be done. They outage is next week or the following week, something like that.

MEMBER LEITCH: That's Unit 2; I didn't

hear that.

MR. HALE: Yes, Unit 2.

MEMBER LEITCH: And Unit 2 doesn't have these sleeves?

MR. HALE: Right, right. So this is only a Unit 1 issue.

MEMBER LEITCH: You would have some problem then complying with the order on Unit 1. I mean, I think what you're saying is you comply with the intent of it, you're confident that there's no problems, but what I'm saying is complying with the specific detail of the order on Unit 1 would be a problem.

MR. HALE: And if the NRC raises that as an issue, and they can't accept what we've done here, we would have to comply with order, whatever would be required. If push comes to shove, we could actually remove the sleeves, but, you know, I think all of us in the industry are considering head replacements and things of this sort, so, you know, that's also on the front end, as well.

MEMBER LEITCH: You have not yet made a decision in that regard?

MR. HALE: Not with regard to St. Lucie. Turkey Point, we are going to replace the heads in

2004 and 2005, even though we haven't seen any indication of leakage.

MR. KUO: Dr. Leitch, staff has some comments on this issue, and Stephanie Coffin, she is a session chief in the Materials Engine Branch.

MS. COFFIN: I just want to make clear what the process is for this. We issued the orders. I believe St. Lucie has asked for relaxation of those orders based on technical document that Steve talked about, that's under review, and we have no, it's pre-decisional right now in terms of what our position is on that.

MR. HALE: I guess my point was whatever the NRC determines we have to do, certainly, we'll have to do under the order. But I think when you look at that, you can see how extensively we have been able to cover from the UT inspections, with exception of certain areas.

MEMBER LEITCH: Okay, thank you.

MR. HALE: Existing programs with GALL, the FAC program, flow accelerated corrosion, was consistent. We did find an area here where we wanted to include enhancements. This is not to meet GALL. This enhancement was just something we felt we needed to do in terms of inspections on some of the small-

bore lines and putting that into our FAC program.

Steam generator integrity program, this is consistent with GALL, but, again, this is a program where we're doing more than what the GALL requires. However, we were able to show that we were consistent with it.

CHAIRMAN BONACA: Or small-bore piping, so have you agreed with staff that you will look for susceptible locations, that you would not use --

MR. HALE: That particular one was related to Class I, which is not related to FAC. This was, you know, where you have safety-related lines, trapped lines, things that come off, like, the main steam lines and this sort of thing, where, you know, if the trap is not working or, you know, they can actually get cold, so you actually get corrosion on the external surfaces, as well, but we're actually using our FAC program, what we call computed radiography, where we can actually inspect both the outside and inside of the pipe as part of our FAC program.

MEMBER WALLIS: Do you get water hammers in those when they get cold?

MR. HALE: No, it just, you know, from sitting there, the traps are interesting because if they sit there closed, then the water cools off. But

if they blow through, then you've got continual flow, and you got a flow accelerated corrosion issue. So we don't get water hammers with them because the way a trap works, you know, once you get a fluid level in it, it's supposed to open and let the fluid pass through.

MEMBER WALLIS: But if you've got accumulation of cold water, you can get some rapid condensation there.

MR. HALE: Yes. What I'm saying is cold is relative. What we found, this is an operating experience issue, what we found at Turkey Point and at St. Lucie is we've had problems with some of these lines primarily due to external corrosion because they're insulated, and if they drop below a certain temperature, you can actually get water on the outside surface to actually start corroding the lines.

We credit our FAC program because, as part of our FAC program, we do what we call computed radiography, which, up to about eight inches, you can actually take a radiographic picture that can actually show you the outside surface of the pipe, as well as the inside surface of the pipe. So you can actually look at both factors at one time. And so we put that in there.

Existing plant-specific aging management programs, our alloy 600 program, fatigue monitoring, fire protection, intake cooling water inspection, and RPM program, we did have some enhancements we recommended for the PM program in terms of getting more specific with regards to certain components and what you look for.

Again, to continue with our existing plant-specific, reactor vessel integrity program is plant-specific, and our systems and structures monitoring programs. And then this is the area where we've expanded to include certain enhancements. It's probably a good idea to speed me along here.

Our new aging management programs, the one that is consistent with GALL, is related to thermal aging and embrittlement. Our new plant-specific programs, we have a storage tank cross tie between Unit 1 and Unit 2. We have a specific program for that. Our containment cable inspection program was a new program that we committed to with the staff, and then our galvanic corrosion susceptibility inspection program.

We have a program specifically looking at certain areas where we've had pipe-wall thinning. Our reactor vessel and internals inspection program and our small-bore Class I. This is the one, Dr. Bonaca,

that you were referring to on whether we're using risk --

MEMBER ROSEN: On the reactor vessel internals inspection program, am I correct in recalling that St. Lucie had some damage, extensive damage to core barrel?

MR. HALE: Yes.

MEMBER ROSEN: I am correct?

MR. HALE: Yes, yes. In fact, we had quite a bit of dialogue with the staff on our barrel repairs. There was a TLAA; that's flagged in the application, which discusses that. We had to re-evaluate, you know, the repair includes patches and plugs and that sort of thing, but we actually had to remove the thermal shield.

MEMBER ROSEN: And so this reactor vessel internals program deals with watching how that repair performs over the extended license term?

MR. HALE: No, actually, what this program is is what we do over and above Section XI. We're already committed under Section XI to do inspections and follow-up with regard to those barrel repairs. So this program is a program that's been instituted to go over and above what we do under Section XI, and it addresses some of the more research-type of things,

like, you know, what's the effect of radiation embrittlement, radiation-assisted primary water, there's a whole series of items right now that are being investigated and looked at under the MRP.

MEMBER ROSEN: I want to come back to the repair program. That was a fairly extensive repair, as I recall.

MR. HALE: Yes, yes.

MEMBER ROSEN: And you're saying that that, the performance of that repair over the extended life of the license now would be controlled by what you do under the code?

MR. HALE: Two aspects: there's a TLAA and a calculational assessment, which is included in the application, plus ongoing visual inspections of the repair areas as part of the Section XI program. So the time dependent aspects of the design with regards to radiation, embrittlement, and fatigue are addressing the application from a calculational standpoint, but, in addition to that, we are doing specific inspections that were required as part of that repair resolution as part of Section XI.

CHAIRMAN BONACA: And the TLAA takes you to 60 years?

MR. HALE: Right, it does. In fact, we

even submitted the proprietary calculation to the staff for their review and independent assessment of.

CHAIRMAN BONACA: Those were expansion patches?

MR. HALE: Yes, yes. If you look at it, it's like a cylinder with a bottom on it and a doubled edge. You actually pressed it in to where you sprung the beveled edge, and then you expanded it inside of the core support barrel.

MEMBER ROSEN: And the staff's presentation of PT, are you intending to comment on that?

MR. DUDLEY: No, we did not include the TLAA on core barrel repair as part in preparation for it, but we can provide you additional information on the review that was done.

MEMBER ROSEN: I would be interested in the short summary, at least, of that review.

MR. KUO: We'll do that.

MR. HALE: Okay. With regards to TLAA's, metal fatigue, certainly, is one area that is addressed. We were able to demonstrate at St. Lucie that our 40-year cycles are bounding for six years. The approach we took to environmentally-assisted fatigue was similar to what we were able to work

through and agree to with the staff at Turkey Point. With regards to EQ, we did incorporate some lessons learned from the Turkey Point review. Where cycle aging was an item that the NRC requested that we address at Turkey Point, we've incorporated that into our St. Lucie assessment.

There was a difference of opinion on how you classify the EQ TLAA's, so we adopted what the staff had recommended that we utilize. And then our information with regards to what we do for temperature and radiation monitoring, we put into the application to address RAI's that we had gotten at Turkey Point.

Other TLAA's: containment penetration, fatigue, rack and cooling system piping, leak before break, crane fatigue. This is the core support barrel repair TLAA that we were speaking of. Alloy 600 instrument nozzle repairs. This is another area where there's a specific TLAA associated with it. We did not find any time-bound license exemptions as part of our review process.

In conclusion, the aging management programs at St. Lucie, we feel we have demonstrated they'll manage the aging effects, so the intended functions will be maintained consistent with our CLB. For all the TLAA's for St. Lucie have been evaluated

and shown to be acceptable for the extended period of operation.

That was the extent of my presentation. Again, I apologize for going over. Any other questions for us?

CHAIRMAN BONACA: So far as the alloy 600 instrument nozzle repairs, the staff can talk about that. Okay.

MR. HALE: We've brought some technical details, as well.

CHAIRMAN BONACA: Yes, I would like to review a little bit that information there, and I think we'll do it when the staff does the presentation. And then the applicant can help us with that. Okay. Thank you very much for your presentation.

MR. HALE: Yes. Thanks for your attention.

CHAIRMAN BONACA: If there is no additional questions, at this point, we'll take a break, and we'll start again at a quarter of 11.

MR. DUDLEY: If visitors want to leave the floor, they need an escort, so let us know, and we'll try to find you an escort.

(Whereupon, the foregoing

matter went off the record at 10:27 a.m. and went back on the record at 10:46 a.m.)

CHAIRMAN BONACA: Okay. Let's get back into session. And now we have the staff presentation.

MR. DUDLEY: Thank you. Good morning. My name is Noel Dudley, and I'm the project manager for the St. Lucie license renewal application review. With me at the table are Tilda Liu, the back-up project manager for St. Lucie, and Jim Medoff, who reviewed the issues related to materials.

As an overview of today's presentation, I plan to summarize the agenda, outline the review conducted by the staff, note the changes to the application resulting from the staff's review, and present the status of the revised oversight process and recent events.

The staff will present the status of the open and confirmatory items and summarize the scoping and screening methodology and the scoping and screening results. After lunch, the staff will present the aging management program inspections; concrete aging, as requested by the ACRS members, this will be the staff's review of the information presented by the applicant this morning; aging

management programs and four of the time limited aging analysis, which the ACRS has requested.

The staff will conclude its presentation by explaining the Interim Staff Guidance process and will provide the status of the identified Interim Staff Guidance issues.

St. Lucie Nuclear Power Plant Units 1 and 2 are combustion engineering plants with large dry containments. Unit 1 is seven years older than Unit 2, which resulted in some design differences between the units.

The St. Lucie process and programs which are associated with license renewal are similar to those used at Turkey Point. The differences between the designs of the combustion engineering plant and the Westinghouse plant introduces some unique aging management and time limiting aging analyses.

When the staff received the St. Lucie license renewal application, the staff reviewed the application in detail and developed the draft request for additional information concerning verification, clarification, and explanation of information in the application. After meeting and discussing the draft RAI's with the application, the staff issued request for additional information that was required for completing the

review, and it was not on the docket. The applicant than submitted responses to these RAI's.

In some cases, additional meetings were held to discuss the draft responses. As a result of these meetings, the applicant revised the draft RAI responses before they were submitted to the NRC. On the basis of the information in the license renewal application and in the RAI responses, the staff prepared the SER with open items, which you've received and were reviewing today or discussing today. Since issuing the SER with open items, the staff has continued its discussion with the application to resolve the open items. Once all the open items and confirmatory items are resolved, the staff will issue a revised SER, which will provide the basis for issuing the license renewal.

As the slide illustrates, the staff and the applicant have expended significant time and effort in this review process. The applicant used the lessons learned from its Turkey Point license renewal application when they prepared the St. Lucie application. About 70 fewer RAI's were issued during the St. Lucie license renewal application review as were issued for the Turkey Point review.

In response to Dr. Ford's questioning

about the reduction in number of RAI's, in some cases, RAI's were issued to get needed documentation of plant-specific information, even though the process had already been reviewed and approved at Turkey Point. So that's some of the reasons for the RAI's is to get that specific information to fill out an accepted position.

As a result of the NRC staff review, new components or commodity groups were identified and subject to an aging management review. Of these, about 75 components required aging management programs. In response to one RAI, the applicant created a new aging management program.

As it turns out, there were about 79, of the 79 new components or structures within scope, about 70 of them were in response to the station blackout II over I and the fan and damper housing Interim Staff Guidance.

Let's see. Slide seven. The NRC staff conducted one audit and two inspections to verify information contained in the application were in responses to the RAI's.

There are 11 open items identified in the SER with open items. The staff has reached resolution on all of these items, and now I will go through each

of the items and explain why the staff accepted the position presented by the applicant.

The first open item resulted from scheduling issues associated with the SER with open items being issued prior to the aging management program inspection report. The aging management program inspection was completed a week before the staff issued the SER with open items, and documentation of the reports was not issued until March 7th, 2003.

Since several of the sections in the SER relied on results of the AMP inspection, we could not, we had to go back and verify when the inspection report came out and whether the supporting information was still valid. The staff has determined that inspection findings support the conclusions in the SER, and this item is resolved, and the staff will revise the appropriate sections of the SER.

The second issue, the staff questioned the management of wall thinning due to internal corrosion of small-bore piping in the fire-protection system. For previous applications, the staff accepted aging management programs that included volumetric inspection of these lines. The fire protection system is supplied for city water, and the applicant's

monitors internal piping conditions via pressure tests, leakage tests, and identification of excessive corrosion products during flushing of the systems.

Past operating experience has not identified any degraded conditions of the internal surfaces, and during recent modifications of the system, the applicant obtained ultrasonic pipe wall-thickness measurements on stagnant portions of the system. The measured wall thicknesses were approximately nominal.

Based upon a nominal wall thickness in the measured wall thicknesses, the applicant determined a worst-case corrosion rate might have occurred over the last 24 years of operation. They then used the worst-case corrosion rate and calculated the pipe wall thickness at the end of the period of extended operations and found the wall thickness would be greater than the ASME B31.1 code requirements for a minimum wall thickness. So based on the volumetric measurements and the corrosion rate calculations, this item was resolved.

CHAIRMAN BONACA: So you still will rely on leakage?

MR. DUDLEY: Not in this case.

CHAIRMAN BONACA: Well, I mean, you're

making a projection that there will be no leakage happening because there is assurance from this projections that the nominal thickness or some level of thickness will still be there. But are there going to be additional inspections, volumetric inspections?

MR. DUDLEY: Yes, there will be continual inspections looking at the pressure, the flow, and the check for corrosion products during the flush.

CHAIRMAN BONACA: Which is the plan they have.

MR. DUDLEY: That's correct.

CHAIRMAN BONACA: But there will be no further volumetric inspections?

MR. DUDLEY: Jay, can you help me out here?

MR. HALE: Let me, if I could, you know, we have a fire protection program which looks at fire protection systems. The issue with regards to ultrasonic as related to wet pipe systems that are pressurized all the time, like fixed sprinkler systems and that sort of thing, if you get any leakage, you would get indication that you had a problem, and you'd have to correct that under the fire protection program.

This was a case of trying to characterize,

you know, whether you're getting any internal corrosion, which may affect sprinkler capability, okay? And we felt that, by looking at the pressure boundary, also looking at volumetric inspections provided a position as to why we didn't need to do volumetric inspection. We still have quite a bit we have to do under the fire protection program, in terms of monitoring fixed systems, testing pumps, ensuring that we get flows at the far end of the system and the right pressure. So I wanted to clarify that.

MR. DUDLEY: Yes. And Jay Rajan was the reviewer for this section, and I'd like him to explain what he was basing the acceptance of the applicant's position on and why this is acceptable to the staff.

MR. RAJAN: As pointed out, we based our acceptance primarily on the flushing pressure testing and performance testing, but this was one of the areas where the flow testing was not being conducted, so we questioned the license how do you verify the acceptability of the wall thickness in those areas. So in some of those smaller lines, they made a one-time inspection and based a corrosion rate, excuse me, estimated a corrosion rate based on the performance of that line and projected it out. It turns out that there was sufficient margin, and we accepted that on

that basis.

CHAIRMAN BONACA: Okay. The reason why I raise the question was that I don't have any problem with this kind of process that you used. My only problem, I guess, is if I think about St. Lucie 2 has only ran for 20 years, not even, so much of it's life is in the future, and we're making a judgment about this program 20 years before we talk into license renewal. I would have liked to see some kind of statement that says we will re-evaluate the piping system and look at it, you know, just a reasonable approach. I'm not asking for inspection and project, at that point, whether or not the experience over the last 40 years tells us that we have to do anything more or less in the next 20. It would give me more comfort than now. Even 20 years of operation and before the next 40-plus, we are already making a commitment to all that we're going to do.

MR. HALE: Well, I think that what's important here is that our fire protection program requires multiple surveillances of all kinds. This was a specific issue related to the internal condition of fixed pipes related to sprinkler system. Unit 1 fire protection system has been there quite some time, 27 years, and, essentially, what we were able to -- in

our water for fire protection, although we classified it as raw water, is domestic water. The water we use in our fire protection system is basically the water that comes out of your faucet. So our feeling was do we need to have a continuing program of ultrasonics to supplement what we already do, which is quite extensive under the fire protection.

MR. MENOCAL: I wanted to add one thing, if I could, too. Even though we did a corrosion, as was mentioned, what we found when we measured the wall thickness was that it was essentially nominal. Now, we didn't have baseline data, so we don't know what the original wall thickness was, so we, very conservatively, added on manufacturer's corrosion allowance, and, basically, the corrosion rate was based on using the high end of the corrosion allowance, which, normally, you don't get that in the pipe. The manufacturers are going to be on the low end, but we added that on to it. It's a very conservative corrosion rate. I don't believe we've seen any significant corrosion at all.

CHAIRMAN BONACA: Fire protection program would require, anyway, testing and inspections.

MR. DUDLEY: The real question that the staff was dealing with here was there was no

expectation that there would be corrosion in the stagnant lines. There was no way to verify whether it had been occurring or not, besides the flush, and whether, after 27 years of operation of the system, getting a volumetric measurement of the wall thickness and actually opening up and taking a look at the internals of the pipe and determining that there was no identifiable corrosion in the pipe, whether that could be used as a one-time inspection to verify the applicant's claim that there was no reason for corrosion to occur in the pipe and use that as a one-time inspection, which would not require any further evaluations or inspections of volumetric proportions or opening your pipe up again. So that was what we were really struggling with was whether that was acceptable to be used as a one-time inspection, and we decided that yes, it would be.

CHAIRMAN BONACA: Let me ask one question now. Given this issue is closed, prior to entrance in the license renewal, the NRC would not look at this issue again.

MR. DUDLEY: That's correct. It now becomes an operating plant issue that, if they do have an operating experience of internal corrosion or a leaking pipe caused by internal corrosion, then,

through the correction action program, the licensee would be required to develop an aging management program to control the now identified aging management effect.

CHAIRMAN BONACA: But the logic, in that case, that's always true of anything, so we didn't need license renewal. Logic, typically, my judgment is that they don't want to bring the component to failure because that could affect the functionality of the system. That's why we have license renewal, so you have sufficient confidence that the testing done for the fire protection system will, in fact, assure functionality, even though there isn't any specific AMR being applied for that function there. I guess that's what we have to rely on.

MR. DUDLEY: That's correct.

MEMBER WALLIS: Your second bullet, minimum is the wrong word. The minimum loss of material would be zero because minimum is the lowest possible. What you mean is they were unable to detect any loss of material, the pipe size of nominal. They didn't really measure loss of material.

MR. DUDLEY: No, they didn't. It was nominal.

MEMBER WALLIS: The pipe size was nominal;

that's the conclusion you already have.

MR. DUDLEY: That's correct. And where they drive the corrosion rate was the uncertainty of what nominal is, the plus and minus of acceptability.

MEMBER FORD: And do I understand it then that, just to follow on Mario's question, I expect it in a stagnant line, which is, essentially, de-aerated over time; there will be very little general corrosion, and your inspections have confirmed that. If you had localized corrosion because of copper getting into the system or whatever it might be, that would identify itself in a leak, which would automatically be found. That is not a safety issue? That's a question. That, therefore, would not be a safety issue; is that correct? If you find a leak, you have to do something about it, but that would not stop the operation of the fire protection system?

MR. DUDLEY: That's correct. The staff does not accept leakage inspection in and of itself as an effective aging management program.

MEMBER FORD: Okay. So you're going to rely on leakage then for localized corrosion events, which this inspection analysis would not cover?

MR. DUDLEY: That's correct.

MR. HALE: But the fire protection program

would.

MR. DUDLEY: Okay, next item. The staff questioned the management of wall thinning due to small-bore pipes in the intake cooling water system. This is an issue we touched on earlier. The environment of the small-bore pipes is stagnant sea water. The staff also questioned the possibility of common node failure of the small-bore pipe during a seismic event. In its response to the RAI and in discussions with the staff, the applicant indicated the following: that there are crawl-through inspections of the majority of the ICW systems line pipes, which include, and my guess is, I'm saying 80% of the pipes in the system. The inspection also included as much of each branch line as possible. The branch lines consist of welded flanges to which small-bore piping is attached. The flanges are the most susceptible location for the development of corrosion cells since there is a break in the epoxy lining where you flange the pipe together.

The applicant has established a program to replace small bore epoxy-lined carbon steel pipes with a more corrosive-resistant material. To date, the applicant has replaced approximately 75% of the carbon steel pipes with the more resistant material.

As part of the nominal shift activities, normal shift activities, operators walk down the ICW system, note any leaks, and initiate corrective action. The ICW system is an open system and is designed to perform its intended function with a sheered three-quarter inch instrument line and an additional hundred-gallon-per-minute leak. These maintenance history shows that the localized failure of cement linings and internal epoxy coating of intake cooling water lines result in small corrosion cells that lead to two-wall leakage. The system and structures monitoring program and the ICW inspection programs are adequate to manage internal corrosion in the ICW piping, and this item is resolved.

CHAIRMAN BONACA: I still have a question about the 25% that has not been replaced. I mean, you're telling me susceptible locations of the joints between the small-bore piping and the larger-bore piping. We have a lot of failures, evidently, and the piping itself led to replacement with more corrosion-resistant material. So I was saying that I understand the reason, but are we saying that we're not going to look at it and license renewal only looks at the connections? I don't understand the logic.

MR. HALE: We credited two aging

management programs for aging of the small-bore lines. One is internal inspections, our visual crawl-through inspection; and the other being leakage inspection. And the basis behind that is part of the corrective action for the other lines be established an acceptance criteria that says we can allow a certain amount of leakage, so if we do get a leak, we'll go in and repair. But it's not affecting the safety function of the system.

CHAIRMAN BONACA: Could I ask you a question? Since you replaced 75%, why didn't you replace also the other 25%?

MR. HALE: Well, part of it is this system is operating all the time, even during outage. It's very hard to work in replacements of this type into a normal, you know, you basically have to take these systems out of service. So because our experience has been small leaks, where the system safety function is not affected, we essentially go into a corrective maintenance mode for these small-bore lines.

CHAIRMAN BONACA: I guess I'm trying to understand logic by which you're putting into aging management for the extended period of time the connecting parts, the joints, between the small-bore and you're not putting this one. I mean, the same

thing you could do for those connections, right?

MR. MENOCAL: I think the only reason that was put in there is to document the fact that when we do the crawl-through, initially, it was thought well, we don't look at the branch connections at all. But we wanted to document and indicate in the response to the questions that we received from the staff was the fact that hey, when you do the crawl-through, you can see so far down the line on the branch connections, and we do, generally, are able to go and see up through the first connection because, generally, there's a flange there up the main process line. You then connect the stainless steel piping, and what we're going through now, our engineering standard now for doing repairs or replacement here.

CHAIRMAN BONACA: What kind of leakage, I mean, would you have to have in order to affect the functionality of this system?

MR. HALE: 100 GPM, plus the sheered three-quarter inch line.

CHAIRMAN BONACA: Plus the sheered three-quarter inch line.

MR. HALE: And that evaluation and assessment was put in place to specifically address this issue.

CHAIRMAN BONACA: Okay. And your position is that the localized damage, I mean, the effects are cells, they're very small; therefore, they tend to be a pinhole, even under the highest demand on the system?

MR. HALE: Right.

MR. DUDLEY: And under seismic concerns, also, a small pinhole leak would not necessarily remove the functionality of the pressure boundary.

CHAIRMAN BONACA: Okay.

MEMBER ROSEN: Did I understand you to say that the small-bore piping is Monel metal?

MR. MENOCAL: One of the replacement materials that we're using is we're going to Monel.

MEMBER ROSEN: One of them and you're going to, but you've already replaced 75%. What did you replace it with?

MR. MENOCAL: Well, our standard right now is replacement with Monel. The reason I'm hesitant to say well, everything's been replaced with Monel through the history of the plant is that we've have a lot of materials we use. We use stainless, okay, for some of the instruments, small lines; Monel; in the past, there have been some aluminum bronze. So there's other corrosion-resistant materials used, but

our standard today is to replace with Monel.

MR. HALE: If we have a leak, replace it with Monel.

MR. DUDLEY: Stu Bailey was one of the reviewers on this item. Stu, could you explain why this acceptable to the staff?

MR. BAILEY: Hi, this is Stuart Bailey. I'm not sure what you want me to add to that last discussion. A lot of the questions that we had were really to make sure that these pipes and lines would maintain their integrity during a seismic event. A lot of the questioning, there's been a lot of discussion about these lines, and a lot of our questioning and the reason for the open items was really to make sure that we had a solid paper trail covering what we're doing here.

The crawl-through on the large-bore piping does allow them, by and large, to look at that first flange. I don't know exactly what population that is of the 25% that hasn't been replaced yet, but that's s significant number of these epoxy-coated lines, where the localized failure of the epoxy or that gap right where the flange is has allowed these little corrosion cells to go in. So the inspections that they're doing really are indicative of overall what

they're seeing in the whole system and would be leading.

And again, as they said, the corrosion really has been in small cells that wouldn't affect the overall integrity of the system during a seismic event. As you said, it really runs all the other safety-related systems, so it needs to remain intact during those events.

So with the combination of the inspections that they're doing on these lines, we feel that they're adequately managing the aging for this system.

MEMBER ROSEN: What I'm trying to get is a picture of where the system is today. What I understand is that there were 75% of the original epoxy-coated carbon steel has been replaced and that it's been replaced with a mixture of Monel metal, piping, aluminum bronze piping in some cases, stainless steel piping; is that correct?

MR. MENOCAL: Yes. That's identified in our application. In fact, when you look at the application, you'll see all those materials.

MEMBER ROSEN: And you're aware of the experience with aluminum bronze and other factors?

MR. MENOCAL: Like bleaching?

MEMBER ROSEN: Not necessarily with piping

but flanges. Not with forge material but cast material.

MR. MENOCAL: I understand. Yes, a lot of aluminum bronze has been replaced in the past.

MEMBER ROSEN: Oh, you replaced the epoxy-lined carbon steel with aluminum bronze, and now you're replacing the aluminum bronze?

MR. MENOCAL: Right. Believe it or not, a lot of the, over the history of the materials of the plant, aluminum bronze, at one time, was thought to be a very excellent material in the industry for salt-water systems, and it was one of the new magic materials that a lot of the industry went to because it was determined to be very excellent.

Then we found, based on our operating experience, that we had the alloy of aluminum bronze at St. Lucie. We didn't have that problem, and so that material was replaced with stainless and another material.

So yes, there's been a progression over the 27 years of operation at the plant where we have made changes in materials and determined the materials not to be ideal.

MR. HALE: I think the point, I guess, that we're trying to make with regards to the intake

cooling water system, we do crawl-through inspections, which are quite extensive. They go through and they crawl through the internals of the pipe. We looked at the connections, had a lot of experience with this system. If you pick a system on our site, which is going to require more attention than any other system, it's going to be this open salt-water system. We probably spend more attention to this system than the other systems from an aging management standpoint.

We've had a lot of operating experience with regards to materials. I'd like to clarify there were some aluminum bronze piping that was part of the original plant design, and we've, through a learning process, lessons learned, our corrective actions, feel that we have an effective way for managing these small-bore lines that consists of an internal visual inspection at the connection because most of our experience has been that's where the leakage has occurred; and, secondly, through visual inspections, we do not operate with leaks in the system. If the leak is identified, a condition report is written, and it's resolved. So those are the two aspects. It's a two-headed program that evaluates that.

Now, in order to ensure that we can adequately meet the safety requirements of the system,

we have a safety evaluation which demonstrates, even with 100 GPM leak and another break in a three-quarter inch connection, that the system can still meet its safety requirements.

CHAIRMAN BONACA: The last question I had for the gentleman here was, in order to feel confident that a seismic event will not, in fact, cause gross failure of the pipe means those were the experiences that you have a corrosion cell, but you don't have multiple corrosion cells in the same location or same area coming up. Is this the case?

MEMBER ROSEN: Let me understand. What size of the small-bore piping? Are we talking about two inch and under or bigger than that?

MR. HALE: Yes.

MR. DUDLEY: It's four to six-inch pipe.

MEMBER ROSEN: So you have some four to six-inch piping, which is aluminum bronze?

MR. MENOCAL: No, I don't believe we have any four to six-inch piping which is aluminum bronze in the intake cooling water system. It's hard for me to speak specifically when you ask me line size of the materials because we have an assortment.

MEMBER ROSEN: No, here's what I'm concerned about. If you have four to six-inch piping

that's made of aluminum bronze, you're going to have four to six-inch flanges of aluminum bronze. The flanges are typically cast, that's where the alloying will occur. And then you have to ask the question about not leakage on normal operation but performance, strength performance in seismic, in event of seismic events. I mean, what are the required strengths of the alloyed aluminum bronze flanges, and are they adequate for 60 years regarding the design basis earthquakes.

MR. MENOCAL: I'm going to tell you, I don't believe we have any aluminum bronze lines that are in the four to six-inch range in the intake cooling water system, and I say that because we have experience with the aluminification of aluminum bronze when we used to have loop water system at St. Lucie for the intake cooling water pumps, which we eliminated and went to --

MR. HALE: Again, the system, we say we're going to have loss of material. Like Tony says, I don't know that we have any four to six-inch aluminum bronze. Again, the carbon steel pipe that's four to six-inch is concrete lined. The only place where we didn't have concrete lining and had to go to epoxy is in the small-bore pipe.

As far as aluminum bronze, in original

plant design, we had some of the loop water system, which was all small-bore, and we've removed all the small-bore lube water piping and have gone to self-lubricated pumps. So as far as de-alloyization, if we had bronze, aluminum bronze, we assume loss of material, okay? That could be from de-alloying, it could be from any factor. If you look at our evaluation, we say we have loss of material. How are we managing loss of material? We're doing it via internal inspections and leakage inspections.

MR. MENOCAL: I guess the key is it's not bare piping. You're concerned with total loss of mechanical properties of the piping because you have de-alloying. The piping is coated; it has some kind of internal coating, whether it's a concrete line or epoxy. But you'll find that the failure mechanism is localized failure of the internal --

MEMBER ROSEN: You're saying the aluminum bronze is concrete lined?

MR. MENOCAL: No, I don't think we have any aluminum bronze in the intake cooling system.

MR. HALE: What we can do is we can provide you details of what pipe is aluminum bronze, but my understanding, if you look at the application, we don't have the facts right here, but aluminum

bronze is small-bore.

MEMBER ROSEN: Okay. That's what I need to know.

MR. HALE: Right. Okay.

MEMBER ROSEN: What the extent of the usage of that material and the largest sizes you've used.

MR. HALE: And I think we clarify in the application what's small-bore.

MR. MENOCAL: Yes, I don't recall the LRA talking about any significant piping that would be subjected to that. Do you have anymore questions on this program?

MR. DUDLEY: No, I think we'll move ahead to the next item.

MEMBER WALLIS: I think you better move ahead. We're going to be here all day.

MR. DUDLEY: As a result of unexpected aging degradation of alloy 600 materials and alloy 182 materials, the staff is developing guidance and requirements for managing these aging effects. To ensure applicants comply with future staff guidance, the staff requested a commitment from the applicant. The applicant committed to implement the commitments made in response to NRC bulletins and any further NRC

communications associated with primary water stress, corrosion, cracking, and nickel-based alloy components. And on the basis of the commitment, this item is resolved, and we've talked already about some of the issues.

MEMBER WALLIS: It's a very strange thing. A commitment, traveling with a commitment is like a promise to implement a promise. Why do you need it? You need another commitment? Maybe a commitment to commit to commit . . .

MR. MEDOFF: Well, let me clarify this for you, okay? The St. Lucie units are CE designed plants. Unlike the Westinghouse designs, they have additional Class I inconel nozzles to things like the pressurizer and possibly the steam generator and the hot legs. Unlike a lot of the Westinghouse applicants, FP&L has opted to develop a low-volt alloy 600 program for all the alloy 600 components in the reactor pressure boundary.

So we've had bulletins out on vessel head degradation of the inconel nozzles to the upper vessel head, but they also have plant-specific experience on some of their other inconel nozzles to things maybe like the pressurizer or the hot legs. And those haven't been addressed by generic communications at

this point.

So you have to differentiate between what's being handled for the head as required by the new orders and how they're handling degradation in the other nozzles at this point. And we had an open item just to specifically clarify the differences, and, basically, the applicant came back and indicated that, currently, for the non-vessel head nozzles, they're just currently using the ASME Section XI requirements at this point.

But we did have a phone call with them, and we did confirm that their commitment is really to implement augmented requirements that we may develop on inconel nozzles but, also, any recommended MRP actions that would be found acceptable to the NRC. So we feel that the commitment covers all the inconel nozzles and not just the ones for the vessel head. They are going to be required to follow the orders for the vessel head nozzles.

MR. DUDLEY: I think, to answer your question, there's a sensitivity among the reviewers that, in the license renewal space, that there is adequate regulatory commitments that inspectors and regulators 20 or 30 years from now can go back and regulate against, so this is really taking license

renewal commitments and ensuring that, even though they're relying on the Part 50 operating plant regulations, that, for renewal of the license, they will highlight the fact that, in this area, for alloy 600, it will be managed by future positions by the staff.

And in the next slide is exactly what Jim described. This is another commitment that alloy 600 materials not connected with the reactor vessel head will also be covered by the requirements of the alloy 600 programs in the future.

MEMBER FORD: Could you expand a little bit on that, Noel? When you look at all the degradation modes for alloy 600 and 690 and 182 and 83, there's a lot of degradation, so when you looked at their alloy 600 program, did it take into account, for instance, whether some of these had already been repaired? And that gives rise to increased concern about future failures. How deeply did you go into their alloy 600 inspection program? There comes this multitude of degradation modes and concerns about prior -- do you understand what I mean?

MR. MENOCAL: Yes, and we had the same issues, so let me explain how we handled it. At RC bulletins 2101, 2201, and 2202 are specific to primary

water stress, corrosion, cracking that occurs in the upper vessel head. It does not address industry experience in other Class I inconel locations, okay? So basically, we divided our open items into two, one on the vessel heads and one on the remaining components, okay? Basically, in the second open item, we asked for clarification what additional inconel components are covered by the scope of your program and what are you doing to inspect them.

They gave us the locations, and they also clarified that, currently, they're just using the current Section XI programs. Now, depending on whether it's, let's say, a nozzle joined by a partial penetration weld as opposed to maybe an alloy 82, 182 safe nozzle weld, which is a full-penetration weld, the ASME Section XI requirements are going to be slightly different for the full penetration, but they'll be maybe a surface exam, volumetric, or a combination of the two. For the partial penetration welds, the only thing that is required at this point are leakage tests, VT2 examinations, visual examinations.

One of the projects in our branch is to look into whether the VT2's for the inconel locations for partial-penetration welds are adequate at this

point; that's probably going to be a project down the road. I think we're looking into it already, but, at this point, we don't have any safety basis for augmenting the requirements for the non-vessel head locations.

Understand that, for their inconel nozzles, to the pressurizer, and the hot legs, they do have an alternative repair that they have a TLAA on, and I'll get into that a little bit more, so that everything is sort of tied together here, and they do have a way of addressing it. But I think for the inconel nozzles in the other locations, I think let's reserve that for the TLAA, and that will maybe clarify.

MEMBER FORD: So your answer is, essentially, you're still relying just on the high level non, really, operational specific.

MR. MEDOFF: What the process would entail, though, if you were worried about, down the road, what happens if we get degradation, if we get severe degradation in a location, the process would be we would look into it, we would issue generic communications, and anything that would come out of those communications would be addressed by the applicants in their responses, and their commitment to

address those communications, we feel, takes care of this.

MR. DUDLEY: Okay. I'll move on to the next item. Staff requested the applicant to clarify what aging management programs were used to manage the aging effect of alloy 600 components not covered by the bulletins. Okay. We're on slide 13? Okay.

The applicant plans to use risk inform methodologies for the one-time small-bore Class I piping inspection. The applicant confirmed that the risk inform methodologies will not be used to eliminate volumetric inspection of weld. In other words, they can't use risk to say we don't need to inspect them. The applicant committed to provide the NRC an inspection plan, provide prior to the period of extended operations, that describes the risk inform methodology and addresses how the methodology will be used to determine the location and the number of small-bore piping components for inspection. This commitment will be included as part of the FSAR supplement.

CHAIRMAN BONACA: So they look at susceptible locations irrespective of risk significance to determine whether or not there is a concern with corrosion of those pipings?

MR. DUDLEY: Yes.

CHAIRMAN BONACA: And that will be one-time inspection?

MR. DUDLEY: Yes, and the details of the program will be provided prior to the period of extended operation. And this open item was a commitment to include specific information in that program description that the staff will need to approve.

CHAIRMAN BONACA: Let me understand now. So you do perform inspections in locations which are not that significant; however, they are susceptible, and you find that there is some --

MR. MEDOFF: Well, no, that's not quite entirely true. This is an aging management program for Class I locations, so they do provide a pressure boundary function.

CHAIRMAN BONACA: Oh, yes. No, I'm saying, but risk inform methodology will tend to focus more on certain specific piece of pipings, and going just for susceptible locations, you're looking irrespective of which one is more significant or less significant.

MR. MEDOFF: I think the approach that they're taking for this is a combination of the

susceptibility in cracking or degradation and how, if you had a failure of that location, how it would contribute to the probable risk assessment.

CHAIRMAN BONACA: So if it is based on susceptible, then you inspect, you find some locations that tell you that there is some vulnerability, so you have to establish additional inspections. The one-time inspection, to me, means that. You don't expect to find degradation, if you find it, you have to do something more, you know, in the future.

So now, in the future, what would you apply? Would you apply a risk inform methodology, or would you just --

MR. MEDOFF: If I could clarify, the history behind the Class I small-bore inspection program is Section XI currently only requires visual inspection of small-bore piping. The concern raised by the staff is that there needs to be some volumetric inspection of the small-bore piping, in addition to Section XI.

Based on our aging assessment, we felt, again, as we have communicated previously, for one-time inspections, we don't anticipate finding anything in this piping. So we've committed, as other applicants have committed, to performing a one-time

volumetric inspection, in addition to the ongoing visual inspections performed under Section XI.

So the volumetric inspection we're performing, since it is small bore, and if you used risk, you probably would eliminate all the small-bore. There was some concern that, you know, we would eliminate certain piping or eliminate the piping by applying the risk inform methodology. Our intent here was that, hey, the inspection technique is volumetric because that is the concern the NRC has raised with the small-bore piping. So what we're doing with risk is we're using risk to establish the locations of the ultrasonic inspections in the small-bore piping.

CHAIRMAN BONACA: So you're not looking -- okay, so you're not looking for the susceptible locations to see if you have a problem, you're looking only for the --

MR. HALE: Well, if I could clarify, as part of your risk inform methodology, one of the factors you consider is CUF and fatigue. So the risk inform methodology will bring into play certain factors where you would expect to see the cracking, your more susceptible areas, as well as other factors.

But the concern that was raised is that we were going to use risk inform to eliminate these

locations from doing volumetric inspection.

So in your answer to your question, one time volumetric inspections but continuing ongoing visual inspections, as we do today, for the small-bore Class I piping.

CHAIRMAN BONACA: So what happens now when you do the volumetric inspection, and now you find that you have some pipes that have degraded, some of them are not in risk of significant location, but they are in susceptible location.

MR. HALE: We would have to, under this program, it specifically indicates that, if we do find degradation, we will have to take specific corrective action, as we would in any case, to deal with that, which may include replacement, it may include ongoing inspections, whatever.

CHAIRMAN BONACA: It may include future volumetric inspection.

MR. HALE: It may include that, you know, depending on what we find.

CHAIRMAN BONACA: So what you're telling me, really, the two programs are somewhat de-coupled, and this is almost base lining your system prior to the entrance into license renewal on the basis that looks not only at risk significance but also susceptibility.

MR. HALE: Right, right.

CHAIRMAN BONACA: All right.

MR. HALE: And this has been an ongoing item that was really raised, I think, originally and right at the beginning with the first applicants that came through, and this is, essentially, we're all approaching it in trying to provide some confidence that --

CHAIRMAN BONACA: Yes. Because some applicants have come before you, and they stated that there were, in fact, concern about symptom areas, susceptibility, and that they identified degradation in some small-bore piping. I don't remember which applicant was that.

MR. MEDOFF: I don't think we've changed. I think the approach taken by the staff --

CHAIRMAN BONACA: I understand that. I'm only saying that your experience is that you don't expect to see any degradation anywhere, but some applicant came that said it wasn't there case. So that's why I think --

MR. HALE: I believe A&O had some specific failures, but they were thermally, there was some thermal-fatigue issues with some small-bore connections. I can't really --

CHAIRMAN BONACA: Arkansas One, yes.

MR. HALE: And we have not seen that.

CHAIRMAN BONACA: Okay.

MR. HALE: In fact, you know, there were other factors involved besides just, you know, small-bore issues. There were some fatigue problems, as well.

CHAIRMAN BONACA: Okay, thank you.

MEMBER LEITCH: There has been recent industry experience with one older plant that had scheduled 40 screwed connections in small-bore Class I piping that yielded some leaks due to, I guess, lack of specificity as far as thread engagement and details of how the system was assembled.

MR. MEDOFF: In a threaded connection?

MEMBER LEITCH: In a threaded connection, yes. I think, in more recent plants, this piping is all welded construction. Is that the case at St. Lucie?

MR. MEDOFF: Let me clarify something. This inspection is specific to small-bore Class I locations that are joined by full-penetration butt welds.

MEMBER LEITCH: Okay.

MR. MEDOFF: Okay.

MEMBER LEITCH: But then my question is is there screwed piping in that service at St. Lucie, particularly St. Lucie 1, I guess.

MR. HALE: St. Lucie 1 is built B31.7, so, as I understand it, I'm not a code expert, but I don't believe screwed connections would be allowed for Class I connections in the ASME code.

MR. MEDOFF: That's a pretty stringent nuclear specification.

MR. HALE: For piping covered by the code. You know, you might have some instrument, but that's outside of the Class I.

MR. DUDLEY: Next item has to do with reactor vessel surveillance capsules. The staff questioned why the reactor vessel surveillance capsule removal and evaluation subprogram removed the last capsule before reaching the peak end-of-life fluents, as indicated in tables 4.2-3 and 4.2-4 in the application.

The applicant explained that the end-of-life fluents in tables are based on 60 effective full-power years. However, the capsule removals in Unit 1 is based on a 52 effective full-power-year fluents, and the capsule removal for Unit 2 is based on a 55 effective full-power-year fluents. And on the basis

of the 52 and 55 effective full-year fluents values, the capsule removal schedules are acceptable. This was a misunderstanding of the information that was provided in the table at the end of the chapter or section concerning reactor vessel embrittlement.

CHAIRMAN BONACA: The projected effective full-power years for 60 years of operation is what? 48?

MR. DUDLEY: Forty-eight is normally what you see.

CHAIRMAN BONACA: This exceeds it.

MR. DUDLEY: This exceeds it, so there's no problem there.

The next issue, the staff questioned the applicants basis for not managing stress relaxation for non-Class I bolting material. Non-Class I bolting does experience stress relaxation at temperatures above 700 degrees Fahrenheit. The non-Class I bolts at St. Lucie are environments that have temperatures below the 700 degrees Fahrenheit, and, therefore, do not require an aging management program specific to stress relaxation.

MEMBER FORD: The use of a specific number, you come across it in the PTS area and other areas, how much below 700?

MR. DUDLEY: I think two or three-hundred degrees.

MR. MEDOFF: Let me clarify how I handled this open item. When I was performing my review, I noticed that the identification of, basically, the applicant has one global aging effect, which is loss of closure integrity, and they evaluate it for different mechanisms, such as severe corrosion or cracking or stress relaxation. And I noticed that, in their identification of this aging effect for the non-Class I was handled a little bit different. They didn't identify stress relaxation as a mechanism leading to the loss of closure integrity. So we asked a question in the open item why, provided justification.

The response we got back from the applicant was, basically, they use different materials for the Class I in contrast to that used for the non-Class I RCS bolting. And they gave us the threshold for stress relaxation was for those materials.

To confirm the validity of the responses, I went to the appropriate ASME section and looked at the footnotes they had stress relaxation. It did confirm that ASME has those thresholds for stress relaxation in different materials.

So based on the use of 700 degrees as the threshold for stress relaxation and Essay 193, Grade B-7 bolting, which is being used for the non-Class I RCS bolting, that stress relaxation would not be an applicable effect for those bolting materials because the operation of the RCS would be at a temperature lower than that. Probably around 560 to 600, so maybe 100 to 140.

MEMBER WALLIS: Not where the bolts are. The bolts are actually cooler than that.

MR. MEDOFF: Right.

MR. DUDLEY: Next slide. The staff questioned the applicant's basis for not managing possible crack propagation from alloy 182 welds in the base metal of the pressurizer nozzles and thermal sleeves. We had touched on this earlier. The thermal sleeves are not welded and do not perform a pressure boundary function. The thermal sleeves are machined, inserted, and expanded. Therefore, since there are no welds, there is no possibility of crack propagation to the base material that forms the pressure boundary, and this item is resolved.

And I'll move onto the next item. The Interim Staff Guidance, the staff stated that the fuse holders are considered passive electrical components

and should be brought into scope of license renewal and subject to an aging management review. The applicant identified electrical boxes that contain fuses that were brought within scope. The fuse holders are located in electrical boxes in the electrical equipment rooms in the Unit 1 and Unit 2 reactor auxiliary buildings. The applicant conducted an aging management review of the effects of aging stressers, such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, and oxidation of connecting surfaces. The applicant concluded that no aging management programs are required.

The staff did extensive review of this since this is the first application that addresses the Interim Staff Guidance on this issue, and some of the things that the staff took into consideration when they reached the acceptance of the applicant's position was that the fuse holders are installed in parallel with breakers to address regulatory guide associated with providing double isolation for non-safety-related loads powered from safety-related power supplies.

The non-safety-related loads include instrumentation and heater strips to electrical

panels. The fuse holder clips are made of copper or a copper alloy plated with a corrosion-resistant material, either tin or silver, and the fuse holders are in a mild, non-air-conditioned environment, and the staff was unable to identify any aging effects that would degrade the performance of the fuse holder. And, on this basis, this item was resolved.

Finally, the last open item, the St. Lucie Units 1 and 2 have experienced instances of alloy 600 instrument nozzle leakage. Four Unit 2 pressurizers steam space instrument nozzles and one Unit 1 reactor coolant system hot leg instrument nozzle were repaired with a half-nozzle repair technology. A mechanic analysis was submitted to support the St. Lucie Unit 2 pressurizer steam space half-nozzle repair performed in 1994. The staff is currently reviewing several aspects of the half-nozzle repair and associated topical reports. The staff is evaluating the acceptability of leaving the half-nozzle repairs in place due to the unknown effects of primary coolant contacting the ferritic material of the nozzles, and this is a spin-off of the Davis Besse concerns.

The staff is reviewing a relief request for leaving the half-nozzle repair in place for one cycle. Combustion engineering identified calculational

errors in its topical report associated with the fracture mechanical analysis supporting half-nozzle repairs, and the staff is reviewing that topical report.

The applicant also submitted a site-specific Class II proprietary calculation for evaluating the crack growth associated with small-diameter nozzles for St. Lucie Units 1 and 2, and that's also under review by the staff.

Since the technical issues associated with the half-nozzle repairs have not been resolved for the current period of operations, the applicant cannot demonstrate that the fatigue analysis can be re-evaluated for the period of extended operations. We're in a position where we, as a staff, do not know what's appropriate for a 40-year time period. Therefore, it's impossible to extend that calculation to the 60-year time period.

However, the applicant committed to implement any further NRC requirements associated with half-nozzle repairs, and, on the basis of this commitment, this issue is resolved, and it's resolved in license renewal space and, again, we rely on the Part 50 operating license base for resolving the adequacy of the half-nozzle repairs.

What's expected to happen is that accepting their commitment, in license renewal space, we can issue the license. As soon as the license is issued, when they come in with another relief request, they'll have to evaluate for the 60-year life of the plan, and the staff will have the opportunity to review that analysis.

MEMBER LEITCH: I don't understand what a half-nozzle repair is. Could someone educate me, please?

MR. MEDOFF: Let me clarify the whole thing.

MR. HALE: We brought a drawing.

MR. MEDOFF: He has a drawing, but, basically, like, the vessel head nozzles, the inconel nozzles to the pressurizer, the hot leg, possibly the steam generator are welded to the ferritic shells or piping using partial penetration welds fabricated from alloy 182 or 82.

Basically, if you look at the drawing, basically, what they do is because of concerns, they do not propose to take out the leaking weld when they have to repair a leaking nozzle. Instead, what they're doing at St. Lucie is cutting the nozzle, basically, in half and installing a new alloy 600

nozzle partially through the thickness of the shell or the vessel.

MEMBER WALLIS: When you say "cutting in half," in which direction are they --

MR. MEDOFF: They have a process to go inside the nozzle and cut the original design, and then they removed the top portion of the alloy 600 nozzle, and they stick in an alloy 600 nozzle partially through, and then they weld it from the top of the -

MEMBER WALLIS: So the cup is across not lengthwise?

MR. MEDOFF: No, it's across. It's across the nozzle. So they cut it across, then they stick in a new alloy 600 nozzle.

MEMBER LEITCH: And that provides a leakage path directly --

MR. MEDOFF: Well, they weld it from the top of the vessel. Let me go through it. When they stick in the alloy 690 nozzle that they're replacing the original nozzle design with, it leaves, there are two things that happen. It leaves the original flaw in the original weld material intact without repair, and it also exposes the ferritic shell or piping component to the borated coolant.

Basically, CE has two designs. One is called a mechanical nozzle seal assembly, which I'm not going to get into right now because they don't use it. But the other is half-nozzle design. There were three time-limiting mechanisms that had to be addressed if they wanted to use this half-nozzle design. One is since you're leaving the flaw intact in the original weld material, you had to address fatigue crack growth into the ferritic material.

The second time-limiting aging effect you had to address was, since you're exposing the original, the ferritic material to the boric acid in the coolant, you had to address severe corrosive attack of the ferritic material by the borated coolant.

And then the third thing, which we concluded wasn't an issue, was possible growth by stress corrosion because, really, you're talking about stress corrosion into a ferritic material, which we haven't concluded is an issue at this point.

So the only thing we've made them do, and the applicant did the appropriate thing, is they identified that we had to address the fatigue crack growth and the ferritic corrosion assessment as time-limiting aging analyses and submitted as part of a TL

life for the half-nozzle designs.

There was some debate with the industry whether they needed relief requests submitted under 10 CFR 50.55 (a) associated with these replacement designs, and we found the clause in Section XI that requires relief.

So under the current operating term, they have submitted a relief request that is now under review by the staff. Included as part of the relief request is the appropriate fatigue and ferritic corrosion assessments for 40 years.

Now, we have some issues that we think CE and the applicant needs to address, but we need more time to look into them, so the process that we're using right now is to issue the relief for one cycle, and the SC should be coming out within the next month or so. And then, to issue the renewed license, and when they have to come back in for relief for the extended period of operation, they'll have to have an appropriate relief, and then the TLAA's will cover 60 years in that case.

So I think, by taking this process, it will give us time to address possible implications of the Davis Besse data on the ferritic corrosion assessment and to take another look at the fatigue

assessment. And I think that's a reasonable approach because it doesn't hold up their license, but they will still be required to do what they will be required to do under the current licensing space.

MR. DUDLEY: Okay. The last slide before lunch, I just want to put this slide up and indicate that there were also confirmatory items, and the confirmatory items were simply to indicate that there would be revisions to requests for additional information responses and several FSAR supplements, as shown on this slide. I don't think I need to go into anymore details but --

MR. KUO: Noel, are you going to go into the ROP process status?

MR. DUDLEY: Yes, I'm sorry, yes. That's the end of the confirmatory items, open items, and I can go into ROP areas, and I should be able to get to this in about five minutes.

MEMBER LEITCH: Just one question before you move into that, Noel. Would you expect that there would be any license conditions? Or do you not make that decision until you're further down in the process?

MR. DUDLEY: At this point, the only additional license condition is that they incorporate

the commitments that are identified in the FSAR supplements and the updated final safety report at the next update.

MEMBER LEITCH: And that's almost a standard, if you will, license condition. Everybody gets that one, I guess.

MR. DUDLEY: Right. So that's why we're concerned about tracking the commitments that have been made during license review process, so that that will become part of the UFSAR and will provide a regulatory basis for inspecting and regulating against the commitments that were made in the license renewal review process.

MR. HALE: And if I could, Noel, what we did with Turkey Point is there is a specific condition of license that's identified which references the SAR supplement and indicates these commitments have to be complete or consistent with the schedule in the SAR supplement. So while they don't identify each one of those commitments as a condition to license, there is a statement in the license which will refer to the commitments made for license renewal.

MEMBER LEITCH: Okay. That's the only condition you expect then, at this point?

MR. DUDLEY: That's correct. We're trying

to identify the commitments that were made and put them into a Part 50 operating licensing space, so they can be tracked as part of the operating license activities.

MR. HALE: With regards to this half-nozzle item, I just want to be, the crux of the issue is really corrosion rate or that piece of carbon steel there. We relied on CE data, and there is some difference of opinion between the industry and the staff, and, with good reason, considering Davis Besse, but our position and the information we provided is to show that this is not an active leak. It's not like the head penetration, but, certainly, we understand the concern the staff has. Our position is that we've done an adequate assessment on the fatigue and the corrosion rate based on available data we had at hand.

The issue that we have right now is what is the right corrosion rate, based on what we're learning from Davis Besse. And I think once we do that, we'll be able to address the balance of this issue.

The fatigue, though, I think, although the staff has not completed their review, the fatigue analysis, we did submit a plant-specific fatigue analysis for St. Lucie.

MEMBER WALLIS: Is there any comparison to Davis Besse at all? I mean, this isn't concentrated boric acid which has been concentrated by flashing and all that stuff. It could be a different temperature.

MR. HALE: It really comes down to evaluating the corrosion rate under three different conditions: one, at 100% power, where you have a very low corrosion rate; at heat-up and cool-down, where you might have slightly higher; and then, possibly, some of these may see just air during shut-down conditions. So it's kind of a complicated assessment to perform to establish what is the aging and whether it is going to. But our feeling is, because it's not an active leak, it's not the same situation. We documented that in some of our RAI responses. But again, that's the crux of the issue is how you establish that corrosion rate and what's the right thing to do, and the industry and the staff have to come to agreement in what is the right assumption there.

MEMBER FORD: But as I understand it, from the license renewal aspect, what you're essentially saying is, hey, this is such a physical unknown in terms of corrosion rates or propagation rights, whether it be fatigue or whether it be stress

corrosion cracking. But we are going to give you a license renewal, but, hey, from now on, you've got to conform to the way industry is, MRP, or whoever else is coming up with these predictions.

MR. DUDLEY: Yes, that's correct. And it's not going to be, I don't believe this is going to be unusual since there is a continued operating experience where we find unexpected corrosion and aging degradation for component and how do you deal with that in the license renewal space during the time that it's been identified and the years that it may take to come to resolution on what's an appropriate aging management program.

MEMBER FORD: Just for interest, are there other stations with this same half-nozzle thing?

MR. MEDOFF: Yes, Arkansas Nuclear One. I mean, Arkansas Nuclear One Unit 2.

MEMBER FORD: Has it also got this?

MR. MEDOFF: Yes.

MR. HALE: Dr. Ford, if I may, what happened is CE submitted a topical to cover this repair methodology the utilities could reference and utilize. In fact, there was actually an SE issued on the topical. There were issues raised by the staff on the adequacy of the fatigue analysis. And in addition

to that, the Davis Besse issued occurred. What has happened is CE has submitted a revised topical to address those issues, and that is yet to be approved yet.

And so the ultimate goal would be come to agreement between the staff and CE and what are the appropriate assumptions in the way you analyze and deal with this modification. And once that's issued, then the rest of the plants will be able to utilize that topical as their basis. Because it's up in the air right now and where we are in the St. Lucie review, I think this is the appropriate way to deal with it until such time as that topical is approved for us.

So that's one of the reasons. I agree with you that this needs to be addressed as a standard repair for the CE plants, and, hopefully, we'll get to that point here.

MR. MEDOFF: And actually, I think the approach we're taking does give us time to address it. We don't take degradation of inconel components lightly, and I think the approach we're taking is to give us time to look at this so we don't rush into an improper conclusion. I'm in constant discussion with my sec chief, Stephanie Coffin, and with my branch

chief, Bill Bateman, about this. We do not want to have another Davis Besse event. We are going to get severely criticized if that happens again.

So I think, right now, by deferring this to the next relief request and to give us time to look into the Davis Besse data on the corrosion assessment and even a chance to re-look at the fatigue assessment, it will give us time to address the TLAA's for the half-nozzle design.

MR. DUDLEY: This is for the revised oversight process. The performance indicators for St. Lucie were last updated in December 2002. All the indicators are green. However, I went back to look at some of the experiences. They've had two trips in the last year. In October of 2000, there was a manual re-trip. Based on the loss of condenser vacuum, they were re-aligning the condenser vacuum system, and, due to the misalignment, they lost pressure. They took the plant off the line.

In April of this year, there was a reactor trip. It must have been occurring during start-up because an auxiliary feed pump tripped, was started and then tripped offline, and I suspect that they lost steam generator water level and tripped offline. Neither of these events were recognized as a

regulatory problem, and there was no non-cited violations issued in response to the trips in either case.

There were several events of not following your radiological control programs. There was one instance of radioactive material, small radioactive spec being carried off-site. There was a long story with that. People were sent in to high radiation areas without the appropriate radiological evaluations. And that was the only area that I could find where there appeared to be several events or missteps by the applicant.

I did come across a finding that, based on results of inspection, this was done by the QA department of Florida Power and Light for St. Lucie. Based on the results of the inspection, no findings of significance were identified. The implementation of the corrective action program was acceptable. There was an isolated maintenance effectiveness issue involving repair of a failed emergency diesel generator cooling system radiator. Overall, the licensee properly classified discrepant conditions and corrective actions were completed in a timely manner with respect to plant risk.

The licensees quality audits were

effective in identifying deficiencies in the license programs, and the inspectors did not observe a reluctance to report safety concerns. And this was taken out of inspection report 2002005 for St. Lucie.

MEMBER WALLIS: So those are comments, in general, about the corrective action program across the board?

MR. DUDLEY: That's correct, and that was made by NRC inspectors.

MEMBER ROSEN: That is very helpful. I appreciate your looking at the operating experience and telling us about the results of the realized oversight process at the applicant's facility.

MEMBER LEITCH: Did I understand you to say that this was a hot particle that was transmitted off-site, or was it --

MR. DUDLEY: They were in the process of decontaminating materials, and several people, when they came out of the radiological controlled area, and Steve may help me out here with details, but they were identified as they were unable to pass through the last rad monitor when exiting the plant. They went through extensive decontamination. One individual, they decontaminated him three or four times, and each time they completed decontamination, they determined

that there was still radioactive material somewhere. They assumed that it was an internal take-up.

It turned out that he had a flea on his underwear. They allowed him the modesty to wear his underwear when they were doing the decontamination, but when he went into the shower, he took off his underpants, took a shower, came back, and put them on. So that's about as far as I can go. Steve, do you have anything --

MR. HALE: As part of the procedures, they are required to do these, you know, and they inappropriately determined that it was internal. But when you do that, when the person comes back into the site, the first thing he has to do is he's got to be monitored. And what happened is, when he came back into the site the next day, he had no internal radiation. So they immediately reacted to that, went to his hotel room with monitoring equipment, and was able to find the flea, as Noel said.

MEMBER WALLIS: So a radioactive flea? There's radioactive fleas?

MR. DUDLEY: That's nomenclature for a very small radioactive particle.

MEMBER WALLIS: Oh, oh.

MR. HALE: But the corrective action has

been, there was a number of corrective actions that fell out of this, but one of the corrective actions is that they have to remove all clothing and put on a modesty garment to do the whole body counting and everything when somebody can't get through the portal monitor when they're leaving the site.

MEMBER LEITCH: Do you have a chronic or an ongoing problem with fuel fleas at St. Lucie?

MR. HALE: I don't believe so. This happened to be a specific case. In fact, it was related to decon up ahead for the full head inspection. And, as you might imagine, it was an abnormal situation in terms of radiation controls and that sort of thing. But it's gotten a lot of scrutiny. In fact, correct me if I'm wrong, Caudle, wasn't there a regional inspection group came in to look at some events that occurred during that. But the way Noel described, it was the event of the hot particle.

MEMBER LEITCH: Okay, thanks.

CHAIRMAN BONACA: Your presentation is completed?

MR. DUDLEY: I'm completed with this portion of the presentation.

CHAIRMAN BONACA: It is a good time to

take a break for lunch.

MEMBER ROSEN: Mario, are we going to go over what open items we have and where we've asked the material and haven't got the answer at some point at the end of the day, or should we do it now?

CHAIRMAN BONACA: I'm sorry, which issue?

MEMBER ROSEN: Well, there's just one open item that I have left.

CHAIRMAN BONACA: Okay. If you want to close it now. We are running --

MR. DUDLEY: If you'll let us know, we can get the answer for after lunch.

MEMBER ROSEN: Okay.

MR. DUDLEY: Which issue is that?

MEMBER ROSEN: The aluminum bronze, the extent of the alloying and the use of aluminum bronze in the ICW system and the adequacy of aluminum bronze for the extended license term.

MR. MEDOFF: In other words, you don't want it looking like it's de-alloy?

MEMBER ROSEN: Let me just say I have a lot of experience with aluminum bronze de-alloy, and I don't want to repeat it.

CHAIRMAN BONACA: Okay. We are running about 40 minutes late, so I hope, in the afternoon, we

can recoup some of the time.

MR. DUDLEY: I think we can make some progress there because, this afternoon, it was more a broad overview of the process.

CHAIRMAN BONACA: Okay, good. With that, I think we need to have lunch, so we're going to take a break for an hour and get back at 10 after one.

(Whereupon, the foregoing matter went off the record at 12:12 p.m. and went back on the record at 1:10 p.m.)

CHAIRMAN BONACA: Mr. Dudley, please resume the presentation. Realize, again, that we are 40 minutes late. Therefore, it would be good to catch up. I see, in the presentations, some of them are of a process nature, and you may make a judgment on what you want to skip.

MR. DUDLEY: We have some preliminary information on the requests from Mr. Rosen, but I'd like to wait until the end of the presentation to see if we get more clarification on the size of the pipes.

CHAIRMAN BONACA: Okay.

MR. DUDLEY: So I'll jump right into where we left off. This afternoon, Greg Galletti will describe the staff's review of the scoping and

screening methodology, and I will summarize the results of the scoping and screening review and the aging management review process. And at this point, I'll turn it over to Mr. Galletti, who also led the scoping and screening review audit.

MR. GALLETTI: Good afternoon, Chairman Bonaca and committee members. My name is Greg Galletti. I'm an operations engineer in the Equipment and Human Performance Branch in NRR. We have responsibility for reviewing the scoping and screening methodology and performing the audit as part of that review process.

What I'd like to do is briefly go over the audit process with you. Again, much of this will be repetitive from what you've heard in the past. And then what I'd like to do is go into, essentially, the big open item that we had, which was the A2 issue, seismic II over I.

And then, if you'd like, I can spend a minute or two going over some insights that we gained from looking at a review performed by a licensee that had the previous benefit of performing a license renewal application in the past, that is Turkey Point. And there's some benefits that we saw in the experience that they gained through that Turkey Point

audit experience that we'd like to share.

With that, let me just get into the basics. The team that I have is, essentially, three members that go out on the audit, and they are members of the Equipment and Human Performance Branch. And in preparation to do that audit, we go out on what we call a procedures documentation review trip, which we go to the licensee, we gather information pertaining to the license renewal application. That is, we go and we get things such as design basis documentation, scoping and screening result reports, any design basis information that may help us review the application and review the process that they went through to determine what systems are in scope and, ultimately, what structures and components are then subject to aging management review.

We go and we get that information and then spend several weeks back in the office doing what we call conservative desktop review. And again, we'll go through the FSAR, we'll go through the application, we'll look at how the application is structured in reference to the requirements of the rule to ensure that they cover the safety-related aspects, the SSC's that are safety related, the SSC's that we would consider non-safety related, and that they have done

an analysis to consider what SSC would be brought into scope as a result of what we characterize as their regulated events.

Once we get through that process in-house, we then go back out to the licensee and spend a full week as a team, three members and the project manager. And during that week, we, again, go through, in detail, the implemented guidelines. In this case, the licensee put together a suite of procedures called engineering instructions, and that suite of procedures was written and implemented in accordance with their 10 CFR, Appendix B, safe quality assurance program, which I think you heard earlier today.

As part of the review, we will go through each of those procedures in detail with the cognizant engineers responsible for that particular discipline. So, for instance, there will be a scoping and structural, mechanical and structural scoping evaluation done, and we would bring in those engineers responsible for that activity at the utility to discuss both the practice, that is the engineer instruction, how well that was understood, how well that was written to reflect the process that the licensee wanted them to perform. And then we'll actually go in and select certain systems to review.

In this case, as we've done in the past, we tried to do what we consider a smart sample. We look at four mechanical systems right off the bat: component cooling water, safety injection, auxiliary feed water, main feed water, and then main steam and condensate.

And there's several reasons why we use this particular group of systems. One is, as you can tell, there's a combination of both safety and non-safety related systems, so we want to get a sense for how they are reviewing and analyzing that information, the design-basis information related to those systems. Secondly, they have pretty robust systems. They're pretty complicated. They've got lots of components. So it gives us a good opportunity to really exercise the process. There's a lot of information, a lot of material, a lot of keen ideas to actually go and review. Thirdly, there's a lot of interface between some of these systems. Some of the systems, the component cooling water would have both non-safety and safety-related components, and between the systems, there would be interfaces. And, as you know, in the past, sometimes these interfaces have been of much interest of the staff in terms of how the licensee has established boundaries, how they've accommodated

equipment at those boundary locations in terms of their process.

Once we go through that process, we'll look in detail at those systems. In this case, we did just that, and we found, quite frankly, that both their implementation guidance was very well constructed, detailed, robust, and provided the guidance that we felt was necessary for their staff to implement their process. And two, we looked at the scoping and screening results reports for these systems, as well as some structures, specifically the auxiliary building, I think we looked at the turban building; there were several other structures that we looked at to try to glean a better understanding of how they implemented the process.

Overall, our findings were that, as I mentioned, their implementing guidance was very well detailed. Their implementation of that guidance and their result in the reports were very well detailed. We didn't find any major deviations in what they provided in terms of the scoping. Their technical basis documentation, the DBD's, the FSAR, all of that sort of information, their hazards analyses to support some of the regulated event reviews were very explicit and provided a very good source for identifying

intended functions for those systems and, subsequently, the intended functions for the components within those systems that were part of the review.

MEMBER LEITCH: Is three days typical for the on-site portion of this inspection?

MR. GALLETTI: Generally, it's about four days. The reason we had limited it to three days in this case is much of the review, the process had been the same as for Turkey Point. So we were coming into this with quite a bit of prior knowledge. Normally, what we would do is come in on a Tuesday and, you know, spend the full week.

As a result, our findings were, basically, that we felt their process was certainly consistent with the regulations they had implemented in accordance with their administrative controls. Again, because they done their review under their Appendix B quality assurance program, we had the added benefit of looking at some of their internal QA audits of their own process. And from that, we gleaned some insights as to how they had performed their activities.

MEMBER ROSEN: Is that unusual the applicants would do these reviews under procedures that are covered by Appendix B? I should think

everybody would do that.

MR. GALLETTI: No, it's not unusual to do it that way but it, quite frankly, some have not chosen to do it under their Appendix B program.

MEMBER ROSEN: I don't understand how they could. I mean, if you read Criterion Three, Appendix B, Criterion Three would say that safety-related activities should be conducted in accordance with approved procedures and instructions.

MR. GALLETTI: Right. Now, these are approved procedures and instructions at all the sites, but it's just the level of, I'd say, scrutiny or, perhaps, pedigree of those procedures where we've seen that some have done it strictly under their Appendix B program. Others have not, although they have quite, you know, approved procedures. They've gone through, like, types of reviews. They've been reviewed, but they don't --

MEMBER ROSEN: I'm not concerned with St. Lucie. I think St. Lucie has done the right thing.

MR. GALLETTI: Right.

MEMBER ROSEN: But now that you raise it, I am concerned about other plants that may not have done it that way and wondering what the justification is at other places. It's just an aside thing.

MR. GALLETTI: Sure, sure. And I understand, and we've asked those questions ourselves when we've gone out. I mean, that's one of the questions we asked, how did you perform this review, and, quite frankly, we have not seen, in the cases where they did not perform it under their Appendix B program, any detriment in the process.

MEMBER LEITCH: Well, that may be so, but I don't know. P.T., are you listening? I mean, for plants that are conducting license renewal activities not in accordance with their Appendix B commitments? I don't think that's correct.

MR. GALLETTI: I don't know if I'd characterize it that way. As much as the process that they use and implemented, the procedures that they use and implemented are not necessarily what they would characterize as quality procedures in accordance with their Appendix B requirements.

MEMBER ROSEN: That's what I'm having a problem with.

MR. GALLETTI: Okay.

MEMBER ROSEN: We can talk about this offline.

MR. KUO: Yes, we can talk about that later on. I think that there is probably a

misunderstanding here that I want to clarify myself.

MR. GALLETTI: But again, for the sake of the St. Lucie review, I think it's clear that their entire process was done under their Appendix B program, and we did find that acceptable.

As to the findings, the one major issue that we did have regarded the 10 CFR 50.54 (a) (2) issue, what we generically term the seismic II over I. And initially, when the application had come in to us, the licensee had performed an internal evaluation of what they characterized as their A2 issues, the non-safety effect and safety. However, just about at the same time, the staff was crafting and implementing their interim staff guidelines on this particular issue. And as you recall, we issued, actually, two staff guidelines, one related to the piping segments and the fluid-filled piping systems, and the second one related to those non-fluid-filled piping systems or other types of SSC's that may come into consideration.

As a result of the audit, we had lengthy discussions on this issue, just articulated, again, the staff's positions and tried to clarify for the applicant exactly what we were expecting of them in terms of a supplemental review. That is, what sort of

industry operating experience and site operating experience did we want them to look at, and, basically, the process or methodology that they would use to explore any additional SSC's, which may have to come into scope.

As a result of that effort, we did issue an RAI, and the applicant came back with what I'll characterize as an extremely detailed, lengthy response to that request. And what the licensee applicant did is they went through an areas-based approach, identified the structures which housed both the safety and non-safety, and then rather than just summarily include everything within those structures, they actually went beyond that to do a pretty detailed review and analysis of the types of interactions that could be expected in terms of leaking, pipe breaking, physical impact, those sorts of things, as well as look at the susceptible equipment. That equipment, whether it was safety related, whether there were some features in place to ensure that any potential hazard would not affect it. Or if a potential hazard could affect it, if it was in some way qualified to handle those sorts of environmental concerns.

Again, we went through that evaluation. We considered the way they implemented it and their

methodology for evaluating that to be very good. As a result, they included some additional systems interscope, and they expanded systems that were already in scope for other regulatory reasons. I think Noel will get into some of the specifics of what specific components they may have included as a result.

But overall, I guess our general conclusion is that their methodology and implementation of that methodology was very robust. Their process was very well defined, and their implementing guidance the engineer instructions. We felt, as a result of many of their reviewers actually having had experience at Turkey Point previously, they were very well versed in the license renewal process, understood the methodology to implement, and were able to do so.

In addition, the licensee provided what I considered rather decent training to their engineering staff, and that encompassed about four different training reviews: some initial on the license renewal review process, formal training on the implementation guidelines and some of the technical tools that they to place to do that. They've got an online database that they use specifically for some of this activity;

it took some time to train on that. And most recently, they've been doing some training again with their engineering staff to try to get a sense for the administrative controls associated with commitments, license renewal commitments.

So with that, we felt that there was reasonable assurance that their methodology was appropriate.

MR. DUDLEY: So I continue?

CHAIRMAN BONACA: Yes, please. You have 20 slides and one hour.

MR. DUDLEY: Okay. What I'm going to do very quick is provide an overview of the scoping and screening results and, secondly, the aging management review process. The purpose of the staff's review of the results of the applicant's scoping and screening methodology is to verify that the applicant has properly implemented its methodology. The staff focuses its review on the methodology results. To confirm that there is no omission of the plant-level systems and structures within the scope of license renewal and that there is no omission of mechanical systems and components, structures, or electrical and I&C components, they are subject to an aging management review.

To conduct its review, the staff used guidance from the license renewal standard review plan and Interim Staff Guidance. The staff reviewed system drawings indicating license renewal boundaries, previous license renewal application reviews, and information in the updated safety evaluation reports to verify there were no omissions in the applicant's results.

As part of this portion of the staff review confirmed that the applicant's responses to Interim Staff Guidance issues concerning station blackout, the II over I issue, and ventilation fan damper housings did not omit any structures or components.

The conclusion required to be reached by the staff is that there is reasonable assurance that the applicant has appropriately identified components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21 (a) (1). Any questions on the scoping and screening results?

I'll go on to the aging management review process. The purpose of the staff's review of the applicant's aging management review results is to verify the applicant has identified the appropriate aging management program for the various combinations

of materials, environments, and aging effects associated with the structures and components that are within the scope of license renewal.

In this case, the staff used existing regulatory requirements or guidance to reach a conclusion on the appropriateness of the aging management program identified by the applicant. This slide contains a partial list of the documents used.

Since the applicant did not claim credit for its aging management reviews being consistent with the GALL report, the staff did not reference the GALL reports in its evaluation of the aging management review results. However, in some cases, the staff used the technical information in the GALL report to provide justification for the acceptability of the applicant's results.

The staff reviewed the aging management program results in Chapter Three, which are identified in six separate system sections, as you see listed on the slides. The conclusion required to be reached by the staff is the applicant has demonstrated the aging effects associated with different structures and components will be adequately managed, so there is reasonable assurance that the intended function will be managed consistent with the current licensing basis

for the period of extended operations, as required by 10 CFR 54.21 (a) (3).

Next, I'd like to bring up Caudle Julian from Region II, and he'll explain the inspection process and summarize the inspection findings.

MEMBER FORD: Just while you're changing your team here, when you say that review process, it involves both sitting at a desk, as mentioned before, and going over the program and discussing amongst yourselves the technical details. When you go to the plant, do you actually do a walk around the plant? Do you stand by people as they're doing various tests, etcetera?

MR. DUDLEY: I think Caudle will get into that.

MEMBER FORD: Great. Fantastic.

MR. DUDLEY: And at this point, I'll ask Mr. Julian, who is a team leader for the scoping and screening inspections and the aging management review inspections to bring its presentation to answer your question.

MR. JULIAN: Thank you. In the first slide, we give you an overview of our license renewal inspection program. I think you've seen this material before. We have a manual chapter 25.16, which is a

high-level document, and a license renewal inspection procedure 71002, which gives us a description of the work we're to do.

For each inspection, we put together a site-specific inspection plan that's reviewed and approved jointly by the region and by NRR. And our schedule is always adjusted to meet the review schedule that's proposed by NRR. We have a pretty much standard template for running through these now, and the regions do their inspections at the appropriate time to support NRR's work.

The resources that we use are a consistent team of the same five inspectors. I think that's good to carry on from plant to plant, so we gain experience. And, from time to time, we lose one, we had one retirement last year, so we have a training program for replacement team members.

MEMBER LEITCH: Do you take a focused look at those same four or five systems that we referred to earlier in the scoping and screening inspection?

MR. JULIAN: We look at nearly all the systems during the scoping and screening, the things that they brought into scope to verify that.

MEMBER LEITCH: Okay. What we were hearing a few minutes ago about the scoping and

screening inspection, they focused on five particular systems, I think I heard them say.

MR. JULIAN: We can take a much bigger sample than that with five inspectors.

MEMBER LEITCH: Okay, thank you.

MR. JULIAN: Our inspections consist of, as we slow on the next slide, the scoping and screening inspection, aging management program inspection, and we have the opportunity to do a third optional inspection, and that decision is made by our regional administrator, Louise Reyes.

MEMBER LEITCH: Has that decision been made in the case of St. Lucie?

MR. JULIAN: Yes.

MEMBER LEITCH: And what was that decision?

MR. JULIAN: We decided that we do not need to do a third inspection for the St. Lucie plant. They came out very clean and very few open items, if any, in my first inspection.

Maybe I can answer your question about scoping and screening. The scoping and screening inspection, the objective is to confirm the output of the process, to confirm the applicant included the appropriate systems, structures, and components in the

scope of license renewal. It's one week in length, and this one was done October 21 - 25, 2002 at St. Lucie at the site. We have done them at corporate office, where that's more appropriate where the work is done there. But we were lucky that it's all done at the St. Lucie site, which we think is much better.

CHAIRMAN BONACA: You do preparation right before the meeting, so you know already where you want to look probably.

MR. JULIAN: Yes, yes. The way we break out the work on this is that we go through the list of systems that the applicant puts in in Chapter Two, and, in that table, which they all have, they'll either say, "This system, we decided, is in scope," or, "Some of them, we decided, are not in scope." And we make a selection of a large number of systems, not all, but all major safety-related systems and systems important to safety, and some that they said are not in scope but we think might be candidates for that. And I divvy this up amongst the inspectors, and they're all assigned a workload of those for the scoping and screening process.

So, here, we're focusing on the systems, and they're to look at the boundary drawings, which all the applicants provide, and any written

documentation, which all applicants have, which supports why this system is in scope. In particular, we're interested on the edges of a safety-related system. On the boundary drawing, there may be things where we'll discuss with the applicant why isn't this particular piece in scope. And we also address, as I mentioned, the notes to see if we agree with the decisions that they made.

At St. Lucie, we thought that they did a good job, and we concluded that the scoping and screening process was successful in identifying those system structures and components needing to be given an aging management review. And their documentation was a very good quality, we thought, with very few minor exceptions that were --

MEMBER LEITCH: Did they use a process that we heard about at Peach Bottom called realignment? That is where certain non-safety systems adjacent to safety systems were scoped with the safety system. For example, where you had, say, an airline penetrating containment, the compressed airline might not necessarily be a safety system, but they included that portion of the line to the outside valves, inside and outside valves as part of the containment. Another approach would be to take the compressed air

system and put it in scope and exclude all the other stuff that wasn't part of the safety function.

MR. JULIAN: Happily, they did the latter.

MEMBER LEITCH: They did the latter? Okay.

MR. JULIAN: Yes. I'm glad we didn't have to contend with realignment at St. Lucie. If they had an instance like that where a portion of the instrument air system needed to be in scope, they would select that portion of the instrument air system out to a boundary valve that needs to be in scope, and they would bring it in. So they would just bring in the pieces of support systems that they needed.

Also, of course, you'd see, at containment penetrations, there would be many, many systems that are non-safety related that penetrate containment, and only that portion between the boundary valves would be in scope. Your answer directly is we didn't have to deal with the concept of realignment.

MEMBER LEITCH: Okay.

MR. JULIAN: We think that's a good thing. Realignment doesn't seem to lend itself well to using the plant's existing, you know, documentation system, and it seems like it would be very confusing.

MEMBER LEITCH: You wind up in the same

place, but it's just a matter of how you get there.

MR. JULIAN: The next inspection is the aging management program inspection, and the objective here is looking at the output to confirm that the existing aging management programs are working well and to examine the applicant's plans for establishing new aging management programs and enhancing existing aging management programs. That was two weeks in length, and the dates were January 13 through 17 and January 27 through 31.

And in this inspection, we were trying to look for things that are existing aging management programs. We want to know how well they've been working, for example. So the boric acid corrosion program that they've had for years will let me see the results from the last two outages, one for each unit, where you did walk down the boric acid problems and let me see the records of what came out of that and let me see your chemistry results for the cooling system for the last two or three months.

MEMBER FORD: And then you go and look?

MR. JULIAN: That's right. We look, first at the records, and if there are things that we can do, can observe that are ongoing, we will do that. Seldom, you happen to hit right at the right time, you

know, that you can actually see some of these things, but there are some things that happened.

And for the inspectors, the systems that they've been assigned during the scoping inspection, I asked them a good opportunity that they have during the first and second inspection to go out and about with one of the system engineers and walk down that system. And the feel there is we want to find out, to the best of our observation, how the systems are being maintained today to give us the confidence that the utility will do good in the future. We know it's a long ways off to the end of the 40-year period, but a snapshot in time is better than none.

There were really no major, major problems that came out of the aging management program inspection. We ran across one where the electrical cable manholes periodic inspection program needed enhancements. I asked for the records that they did on Unit 1 and Unit 2 looking at electrical manholes to see if they are flooded. They do that about, I believe it was every six months they were doing a sample of them. And when we got to comparing it to the drawings, it appears there was inconsistencies between the two units down at the intake structure. They were doing inspections on one unit but not on the

other. And, indeed, there were some safety-related manholes that were not getting inspected at all.

The applicant agreed to that and has since enhanced that program, and I've been told that that has been fixed up now. The good news was that, for the manholes they were inspecting, there were very few instances where there was flooding over electrical cables. There was one a year and a half ago that had to be pumped out, but it was, luckily, a non-safety related.

MEMBER ROSEN: Everybody has yards, everybody has manholes in the yards, everybody has manholes in the yards where rain occurs. It's not the first time we've heard about this. Is there something we need to do with the ISG here maybe? I don't know. It just seems to me that that subject keeps coming up in these reviews.

MR. JULIAN: Yes, it does. It's one of our favorites for inspection during these aging management programs.

MEMBER ROSEN: And it's a real problem. I mean, sites need to make sure that those programs are working and are corrective.

MR. JULIAN: And as we discussed before, some people have very good programs, and some people

have very rudimentary ones. And I think that St. Lucie, in my opinion, was somewhere in the middle. They were doing this as a PM, a preventative maintenance item, and I don't think it received the proper management attention to make sure that they had captured the correct sample to get it done rigorously, and I'm told that they have rectified that now.

MS. FRANOVITCH: Caudle, this is Ronnie Franovitch with the staff. In our GALL report, we do have an A&P that addresses cables exposed to moisture and significant moisture and how that's defined, and it's really a 10-year test. We're in the process of updating the GALL report to add programs that involve things like inspection for moisture. I don't know that we would need to write an ISG on that, but we may be augmenting the GALL report to reflect what applicants have done in addition to that 10-year test. So I just wanted to mention that in passing.

MEMBER ROSEN: Yes, a 10-year test doesn't really thrill me. I mean, it rains much more frequently, if you're lucky, than that.

MS. FRANOVITCH: Yes. The staff recognizes that 10 years is an awful long time, so that's why we may be adding other programs that involve inspection and reconsider the effectiveness of

the 10-year test.

MR. JULIAN: Well, the testing I think that you're considering is actual cable testing --

MS. FRANOVITCH: That's correct.

MR. JULIAN: -- for continuity, and the industry is still working with what kind of a test to actually develop for safety-related electrical cables. Typically, you see all the plants have some rudimentary inspection of electrical manholes and a frequency of six months, especially if you have a rotation, and focus on the ones that are problems to you again and again is the way to do this.

MR. HALE: I think it's important to note that, at St. Lucie and at Turkey Point as well, if you recall, for our median voltage cable, it's lead-sheathed, which is designed for submergence. It was an electrical standard that we put in place, even in our T&D area. And the industry experience indicates that the cable itself in low-voltage applications is not impacted by moisture.

Our primary focus here was the supports and the structural steel and everything else that's associated with this electrical cable in terms of the maintenance. It's still a good practice to maintain these manholes, you know, in terms of reducing the

moisture. From an electrical standpoint, though, in the way we performed our electrical aging management review, from a median-voltage standpoint, moisture is not an issue; and from a low-voltage standpoint, the industry data would support that there's not an issue with moisture for low-voltage cable.

MEMBER ROSEN: But I heard you say it's a good practice to keep the manholes dry. I don't think a good plant lets their manholes fill up with water and stay that way for a long time. It should be detected fairly quickly, the manhole is pumped out and sealed.

MR. HALE: I couldn't agree with you more. The case at St. Lucie, one of the issues we had is not all of the manholes had sump pumps in them, so they were inspecting the manholes with sump pumps, but they weren't inspecting the holes that drain into that one manhole that had the sump pump, and we needed to be looking at those other manholes. So that's why we went ahead and took fairly aggressive action to make sure that we were looking at all manholes.

MR. JULIAN: And we agreed with that. That's the reason we continued to pursue this as an inspection item continually.

MEMBER LEITCH: Where there are new or

enhanced aging management programs, not just manholes, is St. Lucie implementing those programs now, or are we waiting for 40 years to --

MR. JULIAN: In the future. They have an action item tracking system that they have constructed, and they're going to begin work to revise procedures and to construct these programs and put them in place over time. I don't know exactly what their schedule and goal is, but they did not say we're not going to do anything until you're 39, as some applicants have done.

MEMBER LEITCH: For example, on this enhanced manhole inspection and pumping-out program, there's no commitment to do anything with that until you're 39 1/2 but maybe voluntarily --

MR. JULIAN: That's one that they voluntarily did; that's done. That's been finished.

MR. HALE: And I'd like to point out that, although our commitments communicate that we'll have these done by the end of the current licensing period, we took a pretty aggressive stance on implementation. For example, at Turkey Point, we already implemented 70 to 80% of the commitments and integrated them into plant procedures, so we've taken a tact that we will implement everything we can reasonably get done, with

the exception of those where the inspection is going to be performed sometime in the future. Although that's not what's communicated in our formal commitments, that's the tact we're taking internal.

MR. JULIAN: All right. We concluded, overall, that the documentation for aging management programs was of good quality. And with respect to plant condition after our inspectors had gone all over the place looking at plant systems, we were very favorably impressed. One of my inspectors was a former resident inspector at St. Lucie and stayed there for a number of years, and I've been there for a number of years, and our overall conclusion at St. Lucie is that the plant condition continues to improve from what it used to be in past years.

MEMBER ROSEN: Haven't got rid of the noseeums, though. Still out there? Those are real fleas.

MR. JULIAN: Okay. One more thing is that a question was asked earlier. The region administrators decided that we don't need a third optional inspection because the applicant has already established a tracking system for future actions, and we see that they're very responsive in their efforts. That's all I have. Any questions? Thank you.

MR. DUDLEY: Earlier today, the applicant presented its aging management program for the aging effects of phosphate on concrete structures. Dr. David Jeng will present the staff's assessment of the applicant's management of the aging effects of phosphate on concrete and embedded rebar, and I will turn the meeting over to him.

MR. JENG: Good afternoon. My name is David Jeng, and I'm a member of the Mechanical Branch. I am one of the reviewers who reviewed the Section 3.5 containments structures and component supports.

Today, I would like to briefly report to you about the staff's review of below-grade concrete aging management. The staff has a position for the concrete which are below grade that is inaccessible. If they do not expose to the environments, then there will be no need for inspection of those concrete elements. However, if the environment is established to be an aggressive one, then the staff requires an applicant to propose an appropriate aging management program.

The criteria we're judging on whether it's an aggressive environment or not is quite quantitative, and the criteria is shown in the GALL report, which mainly consists of three points. The

first one is the pH of the environment should not be less than 5.5, and the second item is the chloride contents of the ground water in the soil environment should not be larger than 500 PPM. And the third item is solvent content requirements, which the staff maintains they should not exceed 1500 PPM.

In the case of the St. Lucie site, as it was noted by the earlier presentation, the site is quite unique in having an aggressive environment. Specifically, the content of the chloride in the St. Lucie site ground water is in the order of 10,000 to 25,000 PPM compared to 500.

MEMBER ROSEN: 10,000 to what?

MR. JENG: 25,000.

MEMBER ROSEN: 35,000 is pure sea water, isn't it?

MR. JENG: This is chloride.

MEMBER ROSEN: Chloride environment in pure sea water is what? What is the chloride content of pure sea water?

MR. JENG: I'm not an expert on that one.

MR. HALE: I think it's around 22,000 PPM.

MEMBER ROSEN: 23,000. So this is actually, it's higher underneath the St. Lucie, it can be higher on the St. Lucie than in the open sea.

MR. HALE: I don't know. I'm just quoting sea water.

MEMBER ROSEN: It sounds like sea water to me when you're talking 35,000.

MR. HALE: Yes, our ground water is sea. We're right on the ocean.

MEMBER ROSEN: Exactly.

MR. JENG: Now, in terms of sulfate of the St. Lucie ground water, it's in the order of 1,000 to 4,000 PPM, which, I think, is exceeding the staff's 1500 PPM. So for this reason, the applicant took the initiative in the environment is a very aggressive one, and they are calling the proposed aging management program to manage the aging.

The aging management program we are proposing is for systems and structures. And the program mainly contains two sub-items. The first one the applicant is appointed to perform inspections of their assessable below-grade interior concrete elements in services. And the second item is they are going to perform an inspection whenever and wherever excavated structures which are exposed to the ground water.

These two positions consistent with the positions the staff has stated in the GALL report and

has been consistent with some other earlier review actions. Therefore, the staff finds the proposed approach is reasonable and adequate, and therefore, is acceptable.

I would like to make a note that, this morning, the applicant made a quite in-depth and systematic presentation of how they are managing the rebar concrete corrosion and how they assist the phosphate, which may affect the aging of concrete. The staff finds their presentation close on the contents, and the conclusion drawn it's very reasonable and adequate, and we express our concurrence to their presentation information and results.

This concludes my presentation.

MEMBER FORD: Could I just make a comment on your last bullet, inspections conducted and structures are excavated? In other words, you're saying that they must inspect because they are over the spec limit for chloride content, but the inspections are going to be completely random in terms of place and time; is that right?

MR. JENG: It's whenever they have the occasion they have to do some excavation. It's not required to go perform specific excavation. It's

when, for other reasons, in other reasons, they need --

MEMBER FORD: So in other words, it's random?

MR. JENG: Sort of, yes. But you noted that they presented this morning, there are four cases, reasons they inspect it because of other requirements.

MEMBER FORD: I recognize that. But if you were an informed member of the public, and they did find some concrete degradation in some future date, how do you answer the concerned public because you just didn't happen to inspect that region some time? You would be in a terrible mess, wouldn't you?

MR. JENG: Very good, thorough thinking about how we come up with this position. The basis, based on very thorough research of research results is presented in the ACI reports this morning and, also, some 150 years of experience.

MR. DUDLEY: I think the answer to the question is the applicant would have to treat it as any inspection finding where aging degradation is identified and put it into the corrective action program to see if additional inspection should be done to the structures.

MEMBER FORD: Well, are the parts in the structure where, if it did occur, I mean, I agree with you it's unlikely, but if it did occur, it would be a huge impact. Are there places where it would be a huge impact?

MR. JENG: If it did occur, it is the staff's position to treat this item as a degradation item, and they would take appropriate actions to remedy the situation.

MEMBER FORD: Maybe I'm not being very clear. You've made the case that these items in accessible areas or below-grade areas should be inspected, and you're saying that, okay, it doesn't really matter; we'll just do it randomly at time and place as chance would dictate.

MR. JENG: We inspect it first opportunity comes along.

MEMBER FORD: Yes, but that's random in terms of time. Oh, at the first opportunity?

MR. JENG: Yes. When occasion somebody have to excavate some part of the structures because of other operational requirements or whatever the reason.

MEMBER FORD: But that's random.

MR. JENG: That may happen next year, or

it may happen next three years.

MR. DUDLEY: Yes, there's a concern about requiring applicants to go out and dig up around foundations since there is a rubber barrier or a membrane around the structure. So there's a trade-off between going --

MEMBER FORD: Hold on, Noel. The rubber membrane is not stopping the sea water getting to the concrete.

MR. JENG: It will stop the sea water, but only when it's damaged or degraded, then some sea water may --

MEMBER FORD: Well, let me ask a physical question. Are there situations where you could get sea water in contact with the concrete?

MR. JENG: I would say yes.

MEMBER FORD: Okay. So the rubber doesn't matter.

MR. HALE: If I could, Dr. Ford, there's a couple of other things beside just the excavation part of it. One, we do inspect, for example, the heat sink dam regularly. This is a structure that is under water constantly. The other aspect is that we've also included internal inspections of the surfaces of that concrete that's actually below grade. For example, in

the auxiliary building, there are concrete, you can actually go the flow, the flow is actually below the level of ground water, and actually look at bleed through and other indications that would tell you that you do have, you know, some effect from the salt water on the concrete. So it's not just the excavation. The excavation is in addition to things that we do regularly.

MEMBER ROSEN: Are there any techniques for assessing the integrity of the bond between the rebar and the concrete, from external to the concrete, some sort of a radar technique or anything that could be applied from inside, obviously? I mean, some kind of device you could take down to the lowest levels of the plant and put up against the wall that you know is external and see what the interior reads out, see whether there's any integrity?

MR. JENG: Talking about the bond between the steel valves in the surrounding concrete?

MEMBER ROSEN: Yes, the bond, and you can maybe assess the continuity or the integrity of the rebar. I'm just asking a question about whether any such device is available.

MR. JENG: As a concrete structure engineer, I know, yes, testing the strength of the

concrete, and I don't know of any established procedure to determine the bond between the rebars and the surrounding concrete.

MEMBER FORD: So you could go down there and determine the strength of the concrete.

MR. JENG: Yes.

MEMBER FORD: Which would be an indirect measure of whether or not you've had leakage, external sea water leakage into the concrete, which has damaged the concrete, presumably damaged the bond between the rebar and the concrete, and then damaged the rebar, which is carbon steel. Is there any way other than waiting for it to leak, which is what this period inspections of structural interiors is, or waiting until you happen to excavate it? Is there anything better than that?

MR. JENG: The reason we are assuming this position is based on so-called benefit and cost evaluation. I just stress that, over the 150 years of the civil engineering practices and experiences, we haven't experienced any major concern of the sea water being put against the concrete wall would certainly cause some appreciable or a big concern about the safety or the loss of strength.

Occasionally, it may have happened, but

those are infrequent. And whenever they occur, there are processes in place to handle this.

MEMBER FORD: I think you have to qualify your statement. When you saying 150 years, you are not including, you're not confining yourself just to nuclear structures. You're talking about 150 years, and I don't see how you can say that concrete does not degrade in sea water. I don't follow your factual statement.

MR. JENG: Maybe we should define what do you mean by concrete degrade? What do you consider to be a degrade? Engineering, it's our own view why it's okay. When you degrade concrete to the extent it crumbles down and loses the strength and loses function, that's based on the reasons this morning: high-strength concrete, low cement/water ratio, adequate cover, and good aggregate, good cementing, and good construction placement with design. All this stuff is basis for past experience which would almost assure -

MEMBER FORD: But you've got 150 years of experience with those specifications for concrete?

MR. JENG: No. Experience of concrete construction in embedded sea water situation for 150 years. This is off my head, but I think it's a

reasonable number. Thank you very much.

MR. DUDLEY: Next, I want to go through the staff's review of aging management programs. The purpose of the staff's review of aging management programs is to determine whether the programs will adequately manage the associated aging effects. For the aging management programs that the applicant claimed were consistent with GALL report, the staff verified consistency with GALL and the appropriate further evaluations were completed and evaluated associated operating experience.

For the aging management programs that are not consistent with the GALL report, the staff reviewed the 10 attributes of each program, similar to what you have seen in previous applications. In addition, the staff determined that the final safety evaluation report supplements contained an adequate summary description of the programs and activities for managing the associated aging effects.

This next table is taking information from Section 3.0 of the SER, and it summarizes the information concerning the 24 aging management programs in those tables. There were six new programs, and there was also one new program added as a result of a request for additional information, and

there are 17 existing programs. There are 10 common programs, and then 14 system specific programs. And there were 10 GALL programs and 14 non-GALL programs.

The conclusion required to be reached by the staff is that the applicant demonstrated that the aging effects associated with the structures and components will be adequately managed so that the structures and components will perform their intended functions. The staff also had to reach the conclusion that the FSAR supplements contained an appropriate summary description of the programs and activities for managing the effects of aging as required by 10 CFR 54.21 (d).

Next, we can get into the --

CHAIRMAN BONACA: I have a question. Some of these programs, for example the galvanic corrosion, if I remember, susceptibility program contained commitments to either visual or volumetric inspections to be performed. When will these decisions be made? I mean, the programs are vague still about which ones are going to be selected.

MR. DUDLEY: The programs will need to be submitted and approved prior to the period of extended operation.

CHAIRMAN BONACA: Okay. So by that time,

you'll have an iteration because you made us agree, for example, with a proposed approach.

MR. DUDLEY: That's correct.

CHAIRMAN BONACA: So that's part of the implementation phase.

MR. DUDLEY: Yes, and the list of commitments made that are at the end of the SER can be used by inspection teams a few years prior to the end of the present operating period to verify that all the commitments have been met and the programs have been submitted and reviewed and accepted before they enter the period of extended operation.

CHAIRMAN BONACA: But there will be, also, a license renewal specific inspection, right?

MR. DUDLEY: That's correct. We are working and developing an inspection program specifically for license renewal.

CHAIRMAN BONACA: All right.

MR. DUDLEY: I'm not sure if and when you want to take a break, Tim, but why don't we continue on with the TLAA's and see how far we get and how quickly.

MR. HALE: If I could, on the aluminum bronze, we have confirmed that our configuration is consistent with what's in the application in that our

aluminum bronze components are valves, pipings, and fittings associated with vent strains and instrumentation.

MEMBER ROSEN: Which means less than --

MR. HALE: Two and a half-inch and smaller.

MEMBER ROSEN: Okay. So, presumably, you wouldn't have any cast flanges in two and a half-inch and smaller.

MR. HALE: Presumably. Also, we have aluminum bronze pump cases, but we actually --

MR. MENOCAL: In addition, the intake cooling water pump casing, we have sections that are aluminum bronze. But, from what I recall, those casings have a coating on the inside, I guess like a core glass coating; it's an epoxy coating to keep down the potential for erosion of the pump.

MR. HALE: Well, you might mention that they're also removed under the PM program and replaced as required.

MR. MENOCAL: Oh, yes. Those are, and that coating is maintained, periodically disassembled, and refurbished. We have a spare pump that we use to slop out. I don't know the frequency off the top of my head. I think that was a question we had under one

of the RAI's from the staff.

MR. BAILEY: This is Stuart Bailey. Just for clarification, also, for those pump casings, applicant is not relying on leakage detection for those. Applicant uses their periodic surveillance and preventative maintenance program for those.

MEMBER ROSEN: So they're covered by a PM program?

MR. MENOCAL: That's correct.

MR. HALE: And it's on a set timeframe based on operating experience.

MR. MENOCAL: Right.

MEMBER ROSEN: Okay. I'm checking that one off. Thank you. Maybe this is a time, while we're paused here and before we go too far away from what we just got done talking about, Peter, for me to comment about my feelings about what we've heard about below-grade concrete in aggressive ground water environments.

It seems to me that we're undershooting that target dramatically. Periodically, looking for interior leakage is a good thing, but it's after the fact. And being opportunistic, looking at exterior structures whenever they're excavated is a good thing but, as you suggested, it's random. It seems to me

that, given the importance of the integrity of structures exposed to aggressive ground water environments, there ought to be something more done.

I would hesitate, sitting here, to say why, but it should be something that, at least in a sampling way over time, verifies the integrity of the concrete that's exposed to these environments. You could think of something like maybe a coring occasionally at some place, say, yes, take the core out, from the inside obviously, you don't have to excavate, you just go in and drill a core out, say, "Oh, that looks beautiful, just like the day it went in," or, "My gosh, it's all crumbly," and that would be important information. And it seems to me, while I recognize that staff doesn't require it, I'm sitting here thinking what I would do if I had such a plan. I'd certainly want, occasionally, to have more than just, "Well, it isn't leaking, and I haven't found any leakage." It could be happening, and, if it were, that would be extraordinarily important.

MEMBER FORD: I sympathize with the technical difficulty of doing this, and I tend to agree with the presenters on both sides that you asked what do I think, and, yes, I think the likelihood of damage is very high. But if it did occur, then the

consequence could be very great. Therefore, it would be wise to issue a suggestion.

MEMBER ROSEN: Obviously, we're not talking about a widespread sampling program, so you could miss it. You could take the core, and it could look very good in one place, and, 10 feet away, it could be aggressively be --

MEMBER FORD: I'm sympathetic with the idea of looking at the --

MEMBER ROSEN: Oh, I don't want them going in and penetrating the outside barrier.

MEMBER FORD: I'm assuming it was another destructive examination. I'm sympathetic to using that as a kind of Trojan horse, if you'd like. If it's corroding on the sea wall, then I better start to look at my containment.

MR. HALE: I think it's important to point out we do have surfaces that are exposed to sea water constantly that we do look at, and we have not seen degradation there. Where we have seen degradation in concrete have been on areas that are not exposed to salt water all the time, where there's splash or there's collection. For example, horizontal structures where you might get some water seepage that gets into the contract. We've seen that both at

Turkey Point and St. Lucie. But what I think the information that we're presenting here is that, one, by design, you build your concrete such that you would not anticipate to see the kind of corrosion issues we're talking about due to the pressure design, the coverage, and that sort of thing. But in addition to that, we've got surfaces of concrete that are exposed to salt water continually that are visibly inspected, and we have not seen degradation there.

So I think, on those cases where we have excavated at St. Lucie, we haven't seen any. I think that it builds a story that it appears that the design standards that we've developed are performing as we expected them to.

MEMBER ROSEN: And all we need is some verification of that. In my opinion, all we need is some verification of that, and maybe it's as simple as a radar test, you know, looking for rebar integrity. I don't know. Maybe it's some kind of non-invasive test, perhaps, is all you need. Ultimately, you could always do what I suggested first, which was coring from the inside. I really don't want to do that, but I really think that's not good enough. My judgment is it isn't good enough to say we think it's okay because of all the things we've done and the example we have

of the other varied concrete that's okay. It's an issue of importance that should, to me, take some sort of verification. That's just one person's feeling.

CHAIRMAN BONACA: This seems to me a lot of information regarding experience with concrete structures close to sea water before power plants. I mean, bridges, spears --

MEMBER FORD: They would be uniformly bad until you had these -- bridge structures, for instance, are not --

MR. HALE: Falling apart.

MEMBER FORD: They are falling apart, a lot of them. I grant you that they probably will not. That's why I'm saying I don't think it's a huge likelihood that --

MEMBER ROSEN: So you're saying experience has not been good.

MEMBER FORD: But if it did occur because you were not controlling the coring process or something in that building process was not well controlled and you'd have a weak point, then what would the impact be? This goes beyond St. Lucie; I mean this is our generic.

MR. KUO: If I may make a comment. Yes, I agree with you. This is a generic, this is not St.

Lucie specific. That's the first thing. And I do understand that you're concerned about the need for maybe we say it's a better inspection. However, to my knowledge, there have been some non-destructive examination technique applied to concrete. The experience that I knew of, okay, was not very good, okay, because the aggregate of the concrete, okay. So applying those to non-destructive techniques really wasn't successful, as far as I know. It really presents a very difficult task there.

Dr. Rosen talk about taking course. Good idea. However, as you said before, how many course do we have to take? Okay. So if we take the course randomly, again, I'll be facing the same comments Dr. Ford is talking about. How do you know it covered everything? It is a difficult thing to do, and, also, it's quite costly; let's face it, okay.

MEMBER ROSEN: Oh, I'm not thinking about cost right now, frankly. I'm thinking about feasibility and the need.

MR. KUO: Right. The feasibility is there. We could, we could definitely. And then the next question is whether do we have a need there? Based on what the data, the experience that we have collected, just like Mr. Jeng mentioned before, and

look at all the publications out from ATI, really, what it tells us is if you construct the concrete, design the concrete mix, then the potential for the water getting into the rebar is not that great.

MEMBER FORD: If it is built according to specifications, and I don't doubt the likelihood of corrosion occurring or degradation occurring will be small. But was it built according to specifications?

MR. KUO: That, I will have to refer to Mr. Hale. However, I think, as a common practice during construction, for each batch of concrete, we will take a syringical test, and the concrete strength depending on that. So when he said there's 5,000 PSI concrete, that is based on all the syringical tests. And when they construct this concrete structure there, they have to take a test every so often. It cannot exceed two inches or two and a half inches, so that kind of quality control is there. If they follow the quality control, I'm sure this concrete is built according to the code. So that's the assurance, the kind of assurance we have for this type of concrete, especially nuclear plant structures. That's a little bit my --

CHAIRMAN BONACA: We could raise the question regarding any activities in construction. I

mean, you know, is it constructed the way it's supposed to? I mean, hopefully, there was sufficient inspection and testing during to assure that. Now, still, there are questions, you know, but that specific issue, was it built as it should have, hopefully, was answered when it was constructed.

MEMBER FORD: Having been brought up in the world of cracking, I am very sensitive to anybody saying that, you know, it will never happen.

MR. KUO: My previous life was building structures.

MR. DUDLEY: Okay. Next, we'll go through four different TLAA's, and TLAA's are certain plant-specific analyses that are based on explicitly assumed 40-year life, such as aspects of the reactor vessel design. TLAA's also may have evolved since issuance of the plant operating license. For example, analyses supporting core barrel repair or the reactor coolant system half-nozzle repairs.

The staff's review of TLA's confirm that the applicant has evaluated the TLA's by verifying either the analysis is valid for a period of extended operation, or the analysis is projected to the end of the period of extended operations and the results continue to meet the design requirements, or there's

a program to manage the aging effects.

The first TLA I'll discuss is the reactor neutron embrittlement, and that consists of three separate analyses: calculation of the end of life Upper Shelf Energy, the pressurized thermal shock reference temperature, and included the pressure and temperature limits as a discussion item since it's not truly a TLAA.

The analysis of the upper shelf energies for the different reactor vessel belt line materials was projected to the end of a period of extended operations. The results of the applicant's calculated upper shelf energies for Unit 1 reactor vessel ranged from 56 to 73 foot pounds, which are above the acceptance criterion of 50-foot pounds. And the results for Unit 2 range from 70 to 130-foot pounds, which is, again, above the criterion. The staff performed independent calculations to confirm these results.

MEMBER WALLIS: How do they determine these values?

MR. DUDLEY: It's a calculation done in accordance with Reg Guide 1.99, and it's a prescriptive process.

MEMBER WALLIS: Fluents? Is that an

equation for fluents?

MR. DUDLEY: I'll need some help from the technical staff on this. Jim, can you help me out?

MR. MEDOFF: This is Jim Medoff with the Materials and Chemical Engineering Branch. To do our independent calculations, we have a reactor vessel integrity database that includes all the belt line materials for all the U.S. plants, including St. Lucie 1 and 2. For the neutron embrittlement assessments for pressurized thermal shock and Upper Shelf, we did independent calculations of all the materials, and the methods in the database follow the guidelines of regulatory guide 1.99, Revision II, which we've been using for a long time.

MEMBER WALLIS: I thought that was all about RTNDT and that sort of thing.

MR. MEDOFF: Well, RTNDT has to do with pressurized thermal shock. The Upper Shelf Energy is based on charpy impact data, and it's a different criterion. It deals with ductal failures rather than brittle failures --

MEMBER WALLIS: -- letting it from the fluents, are you?

MR. MEDOFF: Yes, the calculations take into account --