UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
***
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
***
MEETING: PLANT LICENSE RENEWAL

U.S. Nuclear Regulatory Commission
11545 Rockville Pike
Room T-2B3
Rockville, Maryland

Thursday, April 29, 1999

The subcommittee met, pursuant to notice, at 8:30 a.m.

MEMBERS PRESENT:
MARIO H. FONTANA, Chairman, ACRS
MARIO V. BONACA, Member, ACRS
THOMAS KRESS, Member, ACRS
DON W. MILLER, Member, ACRS
ROBERT L. SEALE, Member, ACRS
WILLIAM J. SHACK, Member, ACRS
ROBERT E. UHRIG, Member, ACRS.

P R O C E E D I N G S

[8:30 a.m.]

DR. FONTANA: The meeting will now come to order. This is the second day of the meeting of the ACRS Subcommittee on Plant License Renewal.

I am Mario Fontana, Chairman of the Subcommittee for Plant License Renewal. The ACRS members in attendance are Mario Bonaca, Thomas Kress, Don Miller, Robert Seale, William Shack, Robert Uhrig.

The purpose of the meeting is for the subcommittee to review the NRC staff's safety evaluation report concerning Calvert Cliffs' plant license renewal application and related matters.

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

Noel Dudley is the cognizant ACRS 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 published in the Federal Register on April 5, 1999. A transcript of the meeting is being kept and will be made available as stated in the Federal Register notice.

It is requested that the speakers first identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

We have received no written comments or requests for time to make oral statements from members of the public.

Today, we're going to hear from staff on a presentation of their safety evaluation report. Now, Noel has given the ACRS members a

list of the SER chapters and a list of issues, with member assignments. Please get your comments to Noel, who will collect them. These are needed by the full meeting next week so that we can incorporate them into the interim letter.

Also, if you have any questions from the staff regarding the sections that are assigned to you or any additional areas of interest, raise them before the end of the day so that we can receive their replies in time for drafting of our letter next week.

We will proceed with the meeting and I call upon Mr. Christopher Gratton.

MR. GRATTON: Yes.

DR. FONTANA: To proceed.

MR. GRATTON: Thank you. I'm not quite sure whether or not I can speak loudly enough or clearly enough to be heard, but my name is Chris Gratton. I'm the divisional coordinator for license renewal activities in the Division of Systems Safety Analysis, and I was also a reviewer for the Calvert Cliffs license renewal project.

My presentation will be on the scoping and screening portion of the safety evaluation report. During my presentation, I'm going to cover the implementation of scoping requirements, the implementation of the screening requirements, how we handle structures and commodities, open items pertaining to scoping and screening, confirmatory items pertaining to scoping and screening, and the license renewal issues pertaining to scoping and screening.

The staff's goal was to have reasonable assurance that the applicant identified all the structures and components subject to aging management review. In order to get this reasonable assurance, we performed the following reviews to scope the systems, structures and components.

The first thing that we did was we took a complete list of the systems and structures at Calvert Cliffs from Table 3.1 in the application and identified those systems and structures that had license renewal application reports contained in the application.

From those systems and structures, without reports of application, we sampled several systems to determine whether they had intended functions, then we've included them within the scope of license renewal. We've used the FSAR to determine whether the systems had any intended functions.

So our focus was on those systems that were not included in the license renewal application, since the other ones were already in and evaluated.

We did identify some systems and structures that did not have reports in the application, but upon further investigation and through the RAI process, we have satisfactory responses from the licensee that the components that perform intended functions were, in fact, in the license renewal applications in other sections, such as the commodities sections.

From this review, the staff obtained reasonable assurance that all of the systems and the structures with intended functions were identified in the license renewal application.

The second review that we performed, we asked ourselves what

portion of the within-scope systems and structures are required to perform intended functions. For each of the -- I believe there were 66 systems and structures in the application, 35 of which are broken out into individual SERs in our safety evaluation report.

We compared the simplified drawings that were provided by the applicant to the flow diagrams in the FSAR or other docketed diagrams or drawings of the system. We focused on those portions of the system that were not within the scope of license renewal, to ensure that they did not have any intended functions to complete system level intended functions. We used the FSAR to identify the intended functions along with the list of intended functions provided by the application.

Special consideration was given to the boundary valves or boundary points to ensure that they were properly accounted for within the scope of license renewal.

Next, we identified the within-scope components that were in those portions of the systems that were within the scope of license renewal. For each system and structure within scope, Calvert Cliffs provided a list of these components that were within the scope of license renewal. Using the flow diagrams, we validated those lists component by component. We found some emissions, but in interaction with the licensee, we clarified those emissions as either not required to be within the scope of license renewal or the applicant agreed that the characterization of the system boundaries was incorrect and they included those components within the scope of license renewal.

At this point, we had boundaries for our systems and we had a list of components that we had reasonable assurance constituted the entire group of components that were within the scope of license renewal and we went on to our screening portion.

This consisted of an active/passive determination and a long-lived/short-lived determination. The staff compared the list of components within the scope of license renewal to those subject to an aging management review and focused on the applicant's justification for removing items from the second list. The applicant actually provided two lists; one within the scope of license renewal, and a second subject to an aging management review.

The difference between those two lists were removed for one of two reasons, either an active/passive determination or a long-lived/short-lived determination. That's what the staff focused on, to see whether or not that determination was made properly.

What remained from this second -- from this screening process was a list of structures and components subject to an aging management review. Now, I sort of mixed components and structures together and that's because the evaluations were done similarly, although a structure is not a system. The structures were identified individually and broken down into their components and the same process was performed as it was within the system. We identified those portions that perform intended functions. We focused on any portions of a building or a structure that was -- and if it is not within the scope of license renewal, to see if it performed any intended function.

Then we ensured that the list of components was complete and that the components, subject to an aging management review, was also

complete. For commodity groups, the structures and components were assembled in a different manner. The commodity groups, being several different systems, and the staff performed a review of the following type.

The applicant stated that the commodities associated with the within-scope portions of the system were also within scope. In the commodities section, the applicant listed the systems contained in that commodity and the staff verified that the list was accurate by sampling the systems not included on the commodity list.

So in the commodities section, a table was provided of those systems that contained that particular commodity. If it was electrical equipment, it was electrical equipment. If the commodity group was component supports, it was component supports.

Using the boundaries that we had validated in the systems portion, if, say, the feedwater system was listed on there as having a component support, those portions that were within scope, including any piping and structural components that extended beyond the last boundary valve, that were used for structural support for seismic considerations, weren't within scope.

This was true for the commodity groups. This is the same way that we evaluated this. The commodity groups were instrument lines and cables. Cranes and fuel handling was reviewed in an individual section. It didn't span different groups and fire protection system was evaluated as a single system.

As far as open and confirmatory items, we still have four open items. The first one has to do with the station blackout diesel building. It was not included within the scope of license renewal and it was erected in close proximity of the seismic Category 1 EDG building, and there were questions in the staff about whether or not the design of the building brings it within the scope of license renewal. The words in the final safety evaluation report, final safety analysis report, that say that its failure could impact the ability of the EDG building to perform its safety-related function, but the staff is considering, as you will see in the portion on license renewal issues, cascading issues, and that is how far out and what sort of boundaries do we place on scoping and items that do not itself perform safety-related functions or non-safety-related functions whose failure can affect a safety-related piece of equipment.

The second open item. There are several nozzles in the charcoal filter beds that were not scoped within the scope of license renewal. The licensee had indicated that up to the isolation valve for these nozzles, there's a short section of piping and then a spray nozzle. The fire protection staff in DSSA believes that this section of piping, these nozzles are required by 10 CFR 50.48, and we're trying to address that with the licensee staff.

The third issue also is a cascading sort of issue. It has to do with the ductwork that provides cooling to certain rooms within the containment that provide the basis for environmental qualification calculations. Without this ductwork or failure of this ductwork, the EQ requirements may not be maintained. The assumptions that were made in the calculations would not be maintained, and the staff is trying to

address how to handle these secondary issues, failure of a non-safety-related piece of equipment and its effect on a piece of safety-related equipment.

The final open item is just sort of an editorial type of thing. We noticed that there were some inconsistencies between the referencing of individual system electrical commodities and the electrical commodity list. So an open item was issued to make sure that those two sections -- well, not those two sections -- the electrical commodities list, which contains the table of all the systems that have electrical commodities in them and the systems themselves, that they cross-reference each properly, because right now we've found several errors in that relationship.

As far as the confirmatory items go, we have two. Staff has been talking with the licensee about the tendon galleries and their exclusion and we're waiting for resolution on that issue, as well as certain solenoid valves in the containment spray. The information I had on these valves is that they're air-operated valves and they do not contact process systems.

So it's just a matter of identifying the type of valve to see whether or not they would be within scope or not.

Finally, the license renewal issues, there were three in the DSSA section. They covered consumables, which was not addressed in the BG&E application. Consumables, the staff just issued a position on the 20th of April covering structural steel and grease, component filters, system filters, fire hoses, fire extinguishers and air packs.

Staff plans to use that position. It's calling for comments at this time.

Fuses, there was a -- staff put out a position that fuses were active components and BG&E countered that the fuses were, in fact, passive and the -- I'm sorry. Just the opposite.

The staff believed that the fuses were passive and BG&E thought they were active.

The final one is this cascading issue that I addressed earlier, and that is systems that are non-safety-related or relied upon in calculations; you know, should their failures be considered within the scope of license renewal when performing your scoping.

Thank you.

DR. FONTANA: The cascading failures, how do you go about analyzing those? Do you track them from first principles or does it go back to the PRA or something like that?

MR. GRATTON: It was pre-deterministic. For this SBO failure, it was in the FSAR for another reason and the description of the failure was in the FSAR itself and 10 CFR 54.4, the B criteria, non-safety-related, whose failure could affect a safety-related piece of equipment, the EDG structure being the safety-related piece of equipment, it was a direct deterministic evaluation.

DR. FONTANA: Okay. Thank you. Ready to move on?

MR. GRATTON: Yes.

DR. SEALE: When you did these deterministic calculations, were they, in some cases, replications of the calculations that you had done or had been done back when the license was first granted, the

bounding kind of calculation that is used in the licensing basis?

MR. GRATTON: No calculations were actually done. The current licensing basis actually carried forward into the license renewal period. That was one of the bases for performing this review. This was a scoping review, where we tried to bring the design basis events onto the systems and determine which portion of the systems were actually performing the system level intended functions that were described in the FSAR.

DR. SEALE: So you made no attempt to confirm that you could replicate those calculations.

MR. GRATTON: No.

DR. SEALE: The laws of physics haven't changed, but --

MR. GRATTON: Not that I know of.

DR. SEALE: -- there may be other things that have changed in the interval that would make that calculation somewhat difficult at this point, I'm afraid.

DR. FONTANA: Anything else?

MR. GRATTON: Thank you.

DR. FONTANA: Who is next here?

MR. GRIMES: Dr. Seale, this is Chris Grimes, Chief of the License Renewal and Standardization Branch.

I would like to point out that it is our expectation that we may end up going back and looking at the structural analysis for the non-safety-related station blackout diesel building and, using that assessment, to make a determination about whether or not failure of that building and its impact on the safety-related diesel generator building is an appropriate failure to consider for this purpose.

So we may end up going back into that analysis and looking at the conservatisms or the nature of the failure modes.

DR. SEALE: That analysis wasn't in the original licensing basis, was it?

MR. GRIMES: When the station blackout -- no, not in the original licensing basis, but when the station blackout diesel was added, it became a part of the licensing basis.

DR. SEALE: Yes. And you may confirm that.

MR. GRIMES: I expect that we will end up reviewing that analysis to make a final determination on this particular open item.

DR. SEALE: I think we'd be interested in what you find out there.

DR. FONTANA: Okay.

MR. MUNSON: My name is Cliff Munson. I put together Section 3.1, common aging management programs, of the SER. These are programs that appear throughout the -- that are used in the different structures and systems, in a variety of structures and systems.

The first one is the fatigue monitoring program, the second one is the chemistry program, and then the third is structure and system walkdowns, boric acid inspection program, corrective actions program, and the age-related degradation inspection program, ARDI.

So we'll start with the fatigue monitoring program. This program monitors and tracks low cycle fatigue usage caused by pressure or thermal transients for components in the nuclear steam supply system

and steam generator welds, and the cumulative usage factor is used to quantify the fatigue damage resulting from each transient.

The design limit for the CUF is one and corrective actions are to be implemented before this CUF reaches one.

DR. KRESS: It's easy to measure the pressure variations, but thermal variations, you need thermocouples stuck around everywhere.

MR. FAIR: I'm John Fair, the reviewer on this. What they mean by that is they're measuring process temperatures as heat-ups and cool-downs occur.

DR. KRESS: Okay. And then they --

MR. FAIR: In some cases, they do have some more detailed thermal measurements in certain locations.

DR. KRESS: But they just measure the temperature of the fluid.

MR. FAIR: Right.

MR. MUNSON: The fatigue monitoring program is applied to these different systems that I've listed here. As of right now, there are no open items or confirmatory items or license renewal issues for the fatigue monitoring program.

DR. SHACK: How does that handle GSI-190?

MR. FAIR: We separated, in the SER, the monitoring program by itself as a program that just tracks the fatigue from the issues related to fatigue in the other sections, and we discussed the GSI-190 in Section 3.2.

MR. MUNSON: The next common aging management program is the chemistry program. The chemistry programs primarily manage the corrosive action of water for systems containing primary, secondary water, component cooling, and service water. The ARDMS managed by the water chemistry programs include various types of corrosion, from crevice corrosion, galvanic, to general corrosion, pitting, intergranular attack, stress corrosion cracking, intergranular stress corrosion cracking, primary water stress corrosion cracking, microbiologically-induced corrosion, selective leaching, and degradation of elastomers.

For the systems containing primary water, these are a list of the systems containing primary water, and the aging effects that apply to these systems that are managed by the chemistry program.

These are the secondary -- systems that contain secondary water, excuse me, and a list of their aging effects.

DR. SHACK: I assume that this really works -- I mean, they reference EPRI guidelines for primary and secondary water chemistry. What is the commitment, that if EPRI revises those guidelines, what does Calvert Cliffs do?

MR. PARCZEWSKI: Usually, the plants keep abreast of any changes which are made in the guidelines.

DR. FONTANA: Please identify yourself for the transcript.

MR. PARCZEWSKI: Kris Parczewski, from Material Engineering Branch, NRR.

DR. SHACK: But there is no commitment then to --

MR. PARCZEWSKI: There is no specific commitment in the submittal.

DR. MILLER: A question. Several of those systems do involve -- have some radiation. Is there synergistic effects between the chemistry and the radiation effects? Is that addressed in the guidelines? I'm not familiar with the guidelines.

MR. PARCZEWSKI: Those guidelines don't address any radiation effects.

DR. MILLER: Is there any -- I don't know. Bill, do you know about that? Is there synergistic effect from those chemistry -- I'm not a chemist, so I don't know, but some of the systems do involve some level of radiation.

MR. MEDOFF: I'm Jim Medoff, with the Materials and Chemical Engineering Branch. I've done chemistry inspections of plants in Region I. Calvert Cliffs has been one of the plants I have inspected.

Typically, these plants do monitor both the cold chemistry of the reactor coolant system and the radioactive nuclides in their reactor coolant system. In addition to meeting the EPRI guidelines, the plants typically set administrative limits that are more conservative than the EPRI guidelines, because they typically don't want to get to the levels or the limits set by the EPRI guidelines.

So the chemistry departments typically try to maintain the water chemistry to levels that would be consistent or better than would be dictated by the limits set by EPRI.

So from what I have found from my chemistry inspections, the industry has been implementing their chemistry control programs in accordance with the guidelines and, actually, they've been doing such a good job of it, this was one of the reasons they took the chemistry inspections out of the core curriculum.

So I think that the licensees do address chemistry quite well.

DR. KRESS: The answer to the question that he asked is no, that the radiation levels in the cooling system are so small, that it doesn't enter into the chemistry very much.

DR. MILLER: What's the limits on the radiation for that?

DR. KRESS: It's the iodine.

DR. SEALE: Your other question, I mean, the radiation certainly does affect the water chemistry. That's basically why you have a hydrogen over-pressure, to make sure that you don't generate undesirable species because of the radiolysis. You suppress that as part of the water chemistry.

DR. KRESS: Yes, but it's so low that it wouldn't matter anyway.

DR. SEALE: Not the radiolysis product you generate in the core. When you're in a BWR and you're not suppressing, you get a very different chemistry. Not in your concern, but in the corrosion person's concern, it generates a very different corrosive environment, depending on whether he can or cannot suppress those radiolysis products in a PWR.

DR. MILLER: So in a PWR, it's not a concern. In a BWR, it might be a different situation.

MR. PARCZEWSKI: Actually, the iodine, radioactive iodine, which is dissolved in the sump, can be controlled by keeping pH in the sump water about seven, because then the iodine is kept in ionic state

and, of course, then it's not released. So there is a control of iodine, radioactive iodine in the water.

DR. KRESS: Yes. But that has little to do with the corrosion issue.

DR. SEALE: It's a different issue.

DR. KRESS: It's a different issue.

MR. MUNSON: Continuing with chemistry programs for component cooling and service water systems. These are the aging effects listed here. For the chemistry programs, there are no open items, no confirmatory items or license renewal issues.

DR. SHACK: Can I just go back to the fatigue program for a second? When they're monitoring fatigue, they're monitoring these components for some sort of bounding. I mean, they're not monitoring every location, obviously, so they pick bounding locations.

Are these bounding locations for the things that were considered in their original design analysis or have they incorporated industry experience that you're getting fatigue, for example, in feedwater lines that you really didn't anticipate in the original fatigue analysis? Are you bounding those, also?

MR. FAIR: Both are handled. The answer is correct. Most of the locations are based on the original fatigue analysis. However, there were some additional items added, one of them being steam generator nozzles that were a product of industry experience, and they did some fairly detailed monitoring at the plant to come up with their analysis of those nozzles.

DR. SHACK: So they think they've bounded all those locations then with the components.

MR. FAIR: Yes. They think they've bounded the worst case. The monitoring program, as you say, is a sampling program and it relies on picking the worst cases for the sampling.

DR. SEALE: Let me make sure I understand what we're saying and the code words that we're using and all.

I recognize this may not be within the narrow scope of the review of the BG&E application. But nonetheless, there are pilot studies that have been ongoing having to do with in-service inspection that are related to fatigue problems in piping and stress corrosion.

And there are presently applications before the Commission to go to a risk-informed inspection program where the sites of the inspections are picked on the basis of experience with previous problems with systems.

If I read your comments correctly, I gather that the positions that you have identified or that the applicant has identified here as the places where they're doing their fatigue analysis encompass not only the kinds of fatigue locations that were in their original in-service inspection, but also at least some selection of the results of the experience that has been gained over the years of other locations where fatigue has, in fact, been observed.

Now, that doesn't mean that BG&E is asking to go to a risk-informed in-service inspection program, but they are using some of those results in picking the sites for doing their fatigue monitoring. Is that correct?

MR. FAIR: I believe they're using the experience of past problems to pick some of their selected sites. I don't know that risk was factored into any of those decisions.

MR. DOROSHUK: This is Barth Doroshuk, from BGE. We incorporate operating experience into locations that we have in our fatigue program either as an ongoing monitoring point or special analysis. I'm not sure that we care if it's a risk-informed location. We're more concerned about suspicion that there is damage occurring.

So we do not use a risk-informed type of approach when we think there is something going wrong. The locations in the fatigue program would not be removed from the program as a result of using a risk-informed approach. If there was to be a removal of a point in the monitoring program, it would have to be reviewed against 50.59 requirements to ensure that the design basis requirements were still being met.

So even though we are supportive of using risk-informed ISI, we do not use that type of insight to remove locations from the monitoring without proper evaluation.

DR. SEALE: If I may make a comment. The obverse of that coin is that if the ISI -- if the risk-informed ISI programs -- that is, the programs that are based on some sort of risk analysis -- don't pick up the, quote, experience identified areas of concern that you have selected to add to your program, then there is something wrong with that risk-informed analysis. That's the first point.

The second point is that I assume that whatever we're doing in no way prejudices your option down the road to come in and request a modification of your licensing basis to allow you to go to a risk-informed in-service inspection program.

But that's completely removed from and independent of whatever the concerns are that we have right here.

MR. DOROSHUK: I agree with you.

DR. SEALE: Okay.

MR. DOROSHUK: Maintaining the configuration and being able to maintain the flexibility to change as you get insight is an appropriate thing to do and we would -- we believe the commitments that are being put in the application as part of the licensing basis would be modifiable if we did gain the flip-side, which is positive experience, as well.

So we don't think we're handcuffing ourselves at this point.

DR. SEALE: It isn't your intent to do so.

MR. DOROSHUK: No, sir.

MR. STROSNIDER: This is Jack Strosnider, Director of Division of Engineering. I'd just like to confirm that, number one, I agree completely with what you said with regard to risk-informed inspection programs. Our expectation, as you're aware, we're working through these pilots now, is that when done properly, they would identify the more likely locations of failure, that that's part of the consideration there.

So we would expect that that would be the outcome of a risk-informed program.

Secondly, yes, but nothing that's happening in this

amendment is going to preclude someone from proposing a risk-informed inspection program down the road.

The final comment I want to make, which I just think might help in this -- in understanding this section, is to recognize that going through a number of programs here and if we talk about a chemistry program, for example, when you get to a particular system, you may not be relying solely on that chemistry program to manage degradation.

In this case, this fatigue monitoring is really monitoring to compare to the design basis, the usage factor type consideration. For certain systems, there will also be, on top of that, some Section 11 or other inspections that are performed.

So I think it's important to recognize that when you talk about fatigue monitoring, this is not solely what's being relied on to manage the aging mechanisms.

Like I said, when you get into the specific systems, you'll see that, well, yeah, you credit chemistry, you credit perhaps in-service inspection or whatever the appropriate combinations are that will effectively manage the mechanism.

MR. MUNSON: The next common aging management program is entitled structure and system walkdowns. These are walkdowns of structures and systems and components so that any abnormal or degraded condition will be identified and documented, with the goal that corrective actions are to be taken before abnormal or degraded conditions proceed to the failure of the system or structure.

Corrective actions are taken in accordance with the licensee's corrective action program, which is QL2, and at a minimum, these walkdowns should occur at least once every six years for every structure and system.

The walkdowns are to be performed on these following structures and systems, component supports, primary containment structures, all the way through to safety injection systems, instrument lines. I won't go through the whole list.

DR. SEALE: Here, again, you talk about what's going to happen in the future. It's the "going to be". What about the "has been?" I mean, you haven't been boycotting the inside of the plant for the last 20 years. You've been walking around in there up till now and if you found any water on the floor or whatever the expression might be, you've identified the problem and you've taken corrective action.

And I would assume that there would be some corporate memory so that those actions would show up in this program, too.

MR. HEIBEL: This is Dick Heibel, Baltimore Gas & Electric. You're exactly correct. After every outage, the system engineers perform system walkdowns to ensure that the systems are ready to start up. There's also PMs that require walkdowns at this six-year frequency specifically to look at degradation of the system. But all of these systems will get a walkdown by the system engineer at least every two years.

Additionally, the operators have to perform valve lineups after every outage and which valve lineups they do and don't perform is controlled by a procedure that we require them, at a minimum, every two cycles, to do an entire valve lineup.

DR. SEALE: But in addition to that, if you've had any experience in the past, I would assume that somehow you've factored that into your assessment.

MR. HEIBEL: Exactly correct.

MR. STROSNIDER: This is Jack Strosnider. Just to add, again, part of the staff's review is to look at operating experience. We asked questions in that area and the submittal included information on prior experience. So that is taken into consideration with regard to what you might expect in the future or what corrective actions have been taken that might need to continue. So that is a specific part of the review.

DR. UHRIG: In other words, that's just a continuation of the existing program as far as walkdowns are concerned.

MR. GRIMES: This is Chris Grimes. Except to the extent that we look at whether or not the walkdown is addressing a particular aging effect of concern. I think some of the walkdowns have increased their scope or increased -- or changed the guidance to the plant personnel who are going to be looking for particular kinds of degradation.

DR. SHACK: That's the 101 modified procedures we saw yesterday or something like that.

MR. STROSNIDER: In the broader context, the question is what's the operating experience not just for this unit, but even industry-wide, and does your program, whether it's a walkdown program or whatever, does it have the right attributes in it to address that experience.

Part of this gets into identifying what are the plausible aging mechanisms based on looking at experience.

DR. FONTANA: How many walkdowns have been done on six-year intervals so far? The question that I'm getting at is, does six years appear to be a good number.

MR. DOROSHUK: This is Barth Doroshuk, from BGE. The six years is for structures only. As Dick Heibel pointed out, these walkdowns occur when you get down at a system level. Each system engineer is required to walk down all or part of his system on a monthly basis, unless it's negotiated differently with his supervisor.

So this is a much more frequent activity than is represented here, from a detail standpoint. In addition, these activities -- these walkdowns have been formally in place for over ten years, that these procedures or guidelines have been in place and have been, of course, maturing with the results of the inspections.

So the short answer is yes, we do think it's effective, and, of course, we'll continue to refine the program as we conduct the walkdowns. And it has been refined for license renewal in particular, as Mr. Grimes pointed out.

DR. BONACA: Just a question. Operating experience is also used to reduce the number of components which are within the aging management program, correct? For example, I was looking at the instrument lines, where an evaluation of the failures that have occurred over 25 years, and because of the categorization that these are due to poor, inadequate maintenance, a lot of this lining is removed from the

list because we haven't seen aging issues affecting the lines. Is it correct?

MR. GRIMES: This is Chris Grimes. I believe that the characterization is in terms of whether or not there is a reason to believe that there is an aging effect that needs to be managed for those lines.

DR. BONACA: I understand that.

MR. GRIMES: As opposed to removing it, it was more is there a class of instrument line that requires particular attention and an aging management program.

DR. BONACA: Exactly. So I understood that correctly. The question I had is that clearly we -- this is projecting that the future will be like has been for the past 25 years. There may be some incipient aging effect we haven't seen yet, either because we go to extended life or because there are some phenomena that don't manifest themselves -- haven't manifest themselves yet.

How do we -- how do the programs address these issues? Where you don't have -- when looking at certain areas because your program doesn't lead you to do that, you're waiting for the failure of the component or -- I'm trying to understand how does this get done.

MR. STROSNIDER: Operating experience is one part of the review, but it is not considered, in and of itself, sufficient to define whether you need a program in the future.

You also look, based from your knowledge of the type of degradation mechanisms that might be anticipated, you look at research results and then you -- so you look at the potential basically, I guess, just from an engineering or scientific basis of what potential mechanisms might show up and you look for programs to address those.

But there are things that are covered in these programs that have not been observed in operating reactors, but there is an anticipation they could come about. So you look at them.

So I think the important point is, yes, operating experience is considered, but it's not the sole basis for defining the program.

DR. BONACA: Since we're not looking at risk issues or risk importance of components in this program, so there could be some component there that because we haven't seen any aging effect, is not being inspected specifically or looked at. Yet, it is risk significant.

Is it possible that we have the combination there?

MR. GRIMES: We went back to look to see whether or not there were any risk-significant components that were passive that weren't otherwise captured by the deterministic basis. So that's a feature of the review, is to determine whether or not the aging management programs are sufficiently comprehensive.

I'd also like to add to what Jack said, that you mentioned the potential that there might be incipient aging effects that have not yet been manifest. The concept about having the current licensing basis and the existing regulatory process carry over is a recognition that as we learn things in the future and if we identify a new aging effect, and we would like to think that's unlikely because we did a -- we've got about 15 years worth of research that's looked at what are plausible aging effects, what are applicable aging effects, and we've been

reasonably conservative and the applicant has been reasonably conservative about attaching aging effects to things for which, as Jack mentioned, haven't been observed yet, but in anticipation, they might occur, we'll make sure that inspection and maintenance are appropriate.

DR. BONACA: But you see what I was going at. So you have comfort in your review that the programs they have implemented will allow for early detection of degradation in certain components which are passive, but are not part of what is recognized today as being under an aging program.

MR. STROSNIDER: Correct. And I think we have to acknowledge, we don't have a crystal ball, there's been a lot of research done. We're addressing those issues that we consider plausible, things that could happen that we need to look at.

But the other important thing is that these walkdowns and the plant programs, you heard the sort of frequency, there are indicators of -- if new problems show up, these program walkdowns and other inspection activities and stuff will show that that's occurring.

Then we do gain through operating experience and we'd have to factor that in as new issues show up.

So when you go into the renewal period, some of the same programs and mechanisms that you use today for identifying unexpected problems will carry forward into the renewal period.

But the attempt here is to address as much of what you think is plausible as you can.

DR. BONACA: I had a question yesterday. I said that once the license is granted, it's a process that continues. There is no further review, and then they accept that.

The only question I had on the part of the staff is how is the staff planning to monitor, in the next 15 years, not only for this plant, but for the other plants, and see if what they thought was a sufficient basis for the license ten years from now is still going to be good, what have we learned from this process.

I'm trying to understand how you guys are going to do that.

MR. GRIMES: We would intend to do it better than we have in the past, actually, in terms of the programs that we have to change the oversight process, that looks at plant performance relative to its licensing basis on a day-to-day basis, and to constantly challenge whether or not the licensing basis is adequately addressing safety.

We have now developed a program that's going to look at plant performance indicators relative to our expectations about plant performance and that includes program attributes, whether or not the programs are effective, are the events that are occurring -- do they indicate that there is some weakness in either the design or the operation of the facility.

So to get back to your original question, we're working towards a conclusion that is based on comfort that actions have been or will be taken, using the language in 54.29, about the Commission's decision basis, that includes a continuation of feedback mechanism that learns from experience, adjusts as new information comes along, but is constantly looking in areas that are risk-significant or materially significant; that is, like fatigue, looking at potential damage

locations.

So we're confident that the processes will work to carry forward these conclusions and continually challenge them.

DR. BONACA: And I appreciate that. I'm only saying that this is a rule which has a special opportunity for being tested before it really goes into play, and that it will be many years before this plant achieves its 40-year life and walks into the life extension.

I think because of that, there has to be a sensitivity and monitoring almost itself as a rule, because certainly ten years from now, you're going to find that the presumptions which were in the rule and in this review were pretty much correct. We haven't learned anything else that said we really didn't have our act together.

So that's an important point, I think, that there should be some strategy at the NRC level to learn these lessons and monitor.

MR. GRIMES: We agree.

DR. BONACA: And that would give the comfort also to the public and everybody else that these programs are thorough and have a foundation. So there is an opportunity.

MR. MUNSON: For the structure and systems walkdown, there is one confirmatory item. The walkdowns have been amended to detect the aging effects of reinforced concrete structures. Previously, that was overlooked.

The next aging management program is the boric acid inspection program. This program manages the general corrosion of the carbon and alloy steels exposed to concentrated boric acid. The program involves periodic walkdowns of borated systems to look for leakage and subsequent corrective actions to mitigate the effects of the concentrated boric acid corrosion.

This program also manages general corrosion, erosion/corrosion, where, and stress corrosion cracking of various carbon steel reactor pressure vessel components and the program also manages, in part, primary water stress corrosion cracking of alloy-600 components.

The program is applied to the following list of systems and structures.

The open item for this boric acid inspection program is it does not provide for removing interference; thus, some internal portions of the reactor vessel cooling shroud that harbor pockets of liquid may be inaccessible for visual inspection.

The confirmatory item is that the inspection scope is to be expanded to include reactor vessel cooling shroud anchorage to reactor vessel head and reactor vessel cooling shroud structural support members.

DR. SEALE: I don't quite understand your open item. You recognize that some areas are not accessible for inspection as they are presently configured.

MS. COFFIN: That's right. This is Stephanie Coffin.

DR. SEALE: You're going to live with that or are you doing something to --

MS. COFFIN: No. It's an open item for the applicant to address.

DR. SEALE: I see. So they're going to come up with something which you will then assess for its adequacy to remedy that.

MS. COFFIN: That's right.

DR. SEALE: Okay.

MR. MUNSON: The next common aging management program is the corrective action program and this corrective action -- the program is really one of four phases of the maintenance strategy used by BG&E to manage the effects of aging. The four phases are discovery, assessment analysis, corrective action, and confirmation document.

The current licensing basis provides for the assessment, analysis and corrective action and confirmation documentation phases through the implementation of their corrective action program, which is the QL2 corrective action program.

The processes and activities encompassed by QL2 are conducted pursuant to the requirements of Appendix B to 10 CFR Part 50 and cover all structures and components subject to aging management review, and the staff determined that this approach is acceptable to address the population of safety-related structures and components subject to aging management review.

There are no open items for the corrective actions program.

There is a confirmatory item, a description should be included in the UFSAR supplement and for the applicant's -- and/or the applicant's quality assurance policy for the Calvert Cliffs nuclear power plant to confirm that BG&E Appendix B program also applies to non-safety-related structures and components that are subject to aging management review for license renewal, so that these programs can be controlled.

DR. UHRIG: Is this an expansion of QA program?

MR. SOLORIO: This is Dave Solorio. I'm sorry. When you say expansion of the QA program. This is an existing program. It's a very mature program that BG&E has had.

DR. UHRIG: But it's going out to new components, is it not?

MR. SOLORIO: Well, you're shaking your head, Barth, but before I -- so correct me if I'm wrong, but there are certain components that BG&E has said are subject to an AMR that were not safety-related and I believe BG&E will say that some of those components have always been part of their QL2 program.

But the staff's concern was that the documentation, either the QL2 program or the UFSAR, did not specifically call out those components, non-safety-related components, to be within the scope of the QL2 program. Therefore, the staff is just asking for that to be committed to.

MR. DOROSHUK: This is Barth Doroshuk, from Baltimore Gas & Electric. This is not an expansion of the quality assurance program. All the components on-site, whether they be safety-related or non-safety-related, are subject to the corrective action program and controls of Appendix B.

What this confirmatory item does -- so in other words, if we find something wrong, we write an issue report and we walk through the licensing basis checks to check operability issues, irregardless of its classification.

But what this is going to do is recognize that there is an aging dimension that may be needed to be clarified just for -- I guess we talked here yesterday about the culture and changing behaviors, just to make sure that that's captured.

DR. UHRIG: Thank you.

MR. HEIBEL: This is Dick Heibel. To put a little more definition. We would consider it an expansion to the program if it's being subject to QL2, the corrective action program would change a component from being non-safety-related to safety-related. We don't intend to change the designation from non-safety-related to safety-related. But it will still be subject to the -- the entire plant is subject to the corrective action program.

MR. MUNSON: The final common aging management program is the ARDI program. These are one-time inspections to verify that an age-related degradation mechanism does not need to be managed for the period of extended operation or to verify the effectiveness of an existing separate preventive or mitigative type program.

The ARDI is applied to a number of different systems.

DR. SEALE: That's a pretty long list. Basically, you're hoping that plants don't develop post-40-year geriatric diseases, like arthritis and some of these other things that some of us have.

MR. DOROSHUK: Yes, sir. We agree with you. This probably goes right to the question earlier on are we trying -- do we have a crystal ball.

These aging effects that this program is being employed on are on the periphery of -- we haven't seen them yet, but, again, we set the thresholds very low and we're going to go out and do these confirmations. So hopefully these types of activities do try to take into account Mr. Bonaca's concern.

DR. SEALE: Well, when you come up with your crystal ball, maybe someone will come up with a silver bullet to take care of some of our other problems, too.

MR. MUNSON: The open item for ARDI is the staff has identified some age-related degradation mechanisms that we feel require periodic regular inspections and such as for the verification of acceptable condition of codings and verification that corrosion is not occurring due to leakage.

So there were some differences that we had with the licensee with respect to whether ARDI should be applied to different systems.

DR. SEALE: So basically, you moved them into a more disciplined or scheduled inspection mode, right?

MS. COFFIN: If we thought that a one-time inspection wasn't enough, then we asked them to do something more regular.

DR. SHACK: How many of these ARDIs are open to question now?

MS. COFFIN: I don't understand what you mean.

DR. SHACK: I assume that -- it says that they're not acceptable for some of these.

MS. COFFIN: That probably affects about -- I'd have to check -- about three to five systems.

DR. SHACK: Three to five.

MS. COFFIN: Out of --
DR. SEALE: That 15.
MS. COFFIN: Yes.
DR. FONTANA: What specifically? Is there one or two that you can --
MS. COFFIN: You want an example?
DR. FONTANA: Yes.
MS. COFFIN: One example that the staff identified was for the saltwater system, they are going to rely on ARDI to verify corrosion of carbon steel components due to leakage through the system and the staff believes that since leakage can happen anytime throughout the remainder of the plant's life, doing a one-time inspection really is not going to work for that aging effect, and that's something that should be going into the system walkdown kind of a procedure.
Actually, the applicant has decided that that's how they're going to do it and that's more of a confirmatory item for that particular system that I gave you an example.
DR. SHACK: How about the service water? That's like a long-shot for a one-shot inspection.
MS. COFFIN: I'd have to look at the application to look at specifically what kind of aging effect they're particularly addressing. A lot of these things, the applicant gave us a lot of information on the design and the environment. That made the staff feel very comfortable that if there is an aging effect, it's going to be very minimal, and they planned on doing these inspections to verify that assumption, and, of course, if that assumption is incorrect, they're going to be implementing their corrective action program.
MR. MUNSON: That's the conclusion of Section 3.1.
DR. FONTANA: Thank you. Any additional questions on this section?
[No response.]
DR. FONTANA: We'll go on to the next one.
DR. SHACK: John, just before you leave. Have you decided what happens if, in fact, they can't manage to keep something below the line?
MR. FAIR: I'm not leaving. But if you were excusing me, I'll be glad to go.
DR. SEALE: No. In a word.
MR. FAIR: Yes. They would have to write a problem identification report and we had a discussion of this, which they haven't -- there is no specific action they can determine ahead of time, other than it would probably require a look at an expanded scope of components, since this is a sampling procedure, and they have several options for corrective actions; either do some more analyses, propose some additional inspections, or maybe go as far as replacement of the component.
MS. COFFIN: I just want to point out that all these common programs that Cliff just went over today, you're going to be seeing them again and again throughout the presentations, and I don't think most of the presenters are planning to spend a lot of time on all those common programs, since we already went over them.

MR. ELLIOT: My name is Barry Elliot. I'm with the Materials and Chemical Engineering Branch of NRR, Division of Engineering. I'm going to be discussing our review of the reactor vessel, the internals and the reactor coolant system.

The applicant has 19 programs to manage the aging effects of the reactor vessel, the internals and the reactor coolant system. Nine are existing programs, five are modified -- are existing programs that have been modified, and five are new programs.

I don't intend to go through all 19 programs. I'm just going to take and highlight what I consider the most important ones. Some of them I just listened to and I heard a lot of discussion. So you're going to only hear a brief description of the program.

The first program is the water chemistry program. For the reactor coolant system, it established limits on impurities, such as fluorides, chlorides, hydrogen and dissolved oxygen. It measures primary coolant parameters, such as conductivity and pH.

The water chemistry program is used to assure the reactor coolant system will not be subject to corrosion. It's an existing program and will continue into the license renewal term.

The next program is the eddy current examination program for the steam generator tubing. It's an existing program and also will continue into the license renewal stage. It's used to detect denting, where stress corrosion cracking and pitting.

The third program is the in-service inspection program and it picked -- the inspection is a non-destructive examination and a pressure test to determine critical locations and components to manage the effects or where erosion, corrosion and cracking.

This is an existing program. However, as part of our review, based on operating experience, based on knowledge of aging mechanisms, we have recommended additions to these programs and modifications to these programs.

I'll be talking about, later on, the modifications to the ISI program for the internals and the open issues, in particular, there is a series of modifications we are recommending be included or at least right now are open items that might need -- we might need to make adjustments to the ISI program.

DR. SEALE: Barry, just out of curiosity, are all the cooper components gone or copper alloy components gone from their secondary system, so they can truly optimize their water chemistry?

MR. ELLIOT: I don't have an answer to that.

MS. COLLINS: Especially as it affects steam generator tubes.

MR. ELLIOT: The next program I'm going to talk about is the reactor vessel material surveillance program. This program is an interesting one for Calvert Cliffs, because they have one of the best programs in the United States.

In this program, generally, materials are removed from capsules and periodically tested to monitor the effect of neutron radiation in the environment. In the case of Calvert Cliffs, they started with six capsules in their vessel. They've tested -- each vessel. They have tested two from each vessel. So they have four

capsules remaining from their original program.

They have gone out and added to this program. They have added supplementary capsules that they got material from Shoreham. It turns out Shoreham welds were some of the critical welds in Calvert Cliffs Unit 1, also.

In addition, it turns out that McGuire also has material that is related to Calvert Cliffs, so that using the McGuire data to monitor and calculate the neutron irradiation embrittlement for the Calvert Cliffs vessel.

As far as the license renewal -- that's the existing program. We are concerned about two things, generically, in license renewal for vessel surveillance programs. First, that the data bound the neutron fluence for the license renewal period and the second thing is that the data that is gathered, and, in many cases, it could be gathered before the license renewal period ever begins, that it be applicable to the operation of the plant during the license renewal period.

In this case, I don't think it will be a problem for Calvert, because although we've explained this to them, that if they take -- there are two things they have to do. They have to modify their program.

First, they have to extend the surveillance schedule to include capsules out to the neutron fluence at the end of the license renewal period. Second, if they have early withdrawal of capsules, they must establish limits on their operations as far as temperature, flux, spectrum -- that's about all I can think of right now -- that they must operate the plant to and that the surveillance data is useful for.

If they go outside that bound, then they would have to come back to us and either restart the surveillance program, make adjustments to the surveillance program, or tell us how they're going to adjust their irradiation embrittlement estimates.

But I don't think this will be a problem for Calvert. They have a lot of capsules and they should be able to monitor the radiation. That's neutron irradiation embrittlement.

The next is thermal embrittlement, cast stainless steel components.

DR. SHACK: Just a quick question. On that one, do they have lots of margin on their PTS?

MR. ELLIOT: Yes. Well, it's not that they have -- they have -- but I could tell you, the PTS values, they're below the screening criteria at end of license and they're committed, as part of the regulations, to monitor this. In fact, six months ago, they submitted a new estimate and they're still -- and their estimate included the license renewal period and they're significantly below the screening criteria for both units.

DR. SHACK: I take it that they're even still at 50 foot pounds for the --

MR. ELLIOT: Fifty foot pounds upper shelf energy. They did an analysis that shows that at the end of the license renewal period, they'll be just above 50 foot pounds, like 51 or something like that. This will be monitored as part of the vessel surveillance program.

The thermal embrittlement portion is a new program, the cast austenitic stainless steel program, and this program is to identify cast stainless steel materials that are susceptible to thermal embrittlement based on the percentage of ferrite, the amount of molibnimum, and the casting methodology.

The criterion-associated analyses are documented in EPRI topical report 106-092. The criteria was developed using measured and saturation lower bound JR curves. The saturation lower bound curves were developed by Argonne Laboratory from tests on age, cast stainless steel material. In all cases, the Argonne prediction curves were equivalent or conservative compared to the measured values.

Staff reviewed the topical report and submitted an evaluation, I think, to NEI and we've discussed it with Calvert Cliffs. There are some modifications that are necessary to the program. A few of the -- one criteria has to be changed. The method of calculating ferrite has to be a particular way and the inspection method of -- should we be recommending that it be qualified to Appendix 8, if they can develop techniques that can qualify this.

This materially is very hard to ultrasonically inspect, but we're hoping that the industry will put an effort here and be able to qualify an inspection procedure for this type of material.

DR. SHACK: I'm curious about that, because it had comments about niobium in the stainless.

MR. ELLIOT: Yes. One of the things we said is that if there's any niobium in the cast stainless -- these are part of the limits. We modified the limit on -- we modify a ferrite limit for high molibnimum, but if there is any niobium in the cast stainless steel, then this criteria would not apply, and the material would have to be inspected.

DR. SHACK: Did they really have enough foresight to analyze for niobium in their cast stainless?

MR. ELLIOT: They said they're going to look into it.

MR. BALDWIN: Marvin Baldwin, with Baltimore Gas & Electric. Cast was one of the areas we looked at very closely. We reviewed the certified material test reports that we got from Combustion Engineering, from fabrication, and determined that we have no niobium. Niobium was neither specified in the fabrication of any of the cast components that are in the RCS pressure boundary.

DR. SHACK: I'm sure it wasn't specified, but was it analyzed to find out if it got in some other way?

MR. BALDWIN: I recall seeing niobium on the data sheets for some of the CMTRs. I can't say that I saw them for all, but what I did was I -- I'm not a metallurgist, but I know how to look at documentation to see what's there, and I did see NB or, I think it was called something different before, I forget what it was, and I did see those on some, where there were blanks or no numbers.

DR. SEALE: I'm not sure I understand where this niobium is supposed to be. What if you went to a different cladding material?

MR. ELLIOT: Excuse me. This is not cladding. This is cast austenitic stainless steel.

DR. SEALE: That's what I said. I didn't know where the

niobium was supposed to be. So you've answered my question.

MR. ELLIOT: Okay.

DR. SHACK: It's not supposed to be there.

MR. ELLIOT: Yes, it's not supposed to be there.

DR. SEALE: I know, but if we talk about high burn-up fuels and the possibility of modifying cladding.

MR. ELLIOT: This issue, you could -- I mean, Bill knows a lot about this.

DR. SEALE: I'm sure he does.

MR. ELLIOT: I think the French reactors, I think, specified niobium.

DR. SHACK: No, they didn't, but they got it.

MR. ELLIOT: They got it. And so that's why this was a concern that was raised and specifically if there is niobium, then all the criteria don't apply and the materials would have to be inspected.

The next program is a modification to the ISI program. It's the internals inspection. It's the internals program. I was listening before about here is a case where the licensee says really there is no problem, but the staff has decided that there is a potential problem in the future.

In this case, the internals are subject to high radiation and what we're concerned about here is radiation-assisted stress corrosion cracking as well as just general embrittlement of the stainless steel.

Another part of this is that we also have the cast stainless components also in this internals. So not only are they going to have the neutron embrittlement, but they're also going to have the thermal embrittlement of those components.

At the moment, there is very limited data available for neutron embrittlement of stainless steel. The applicant is participating in an industry program to develop that data.

However, until that data has gotten analyzed, we have decided that the ISI program needs to be enhanced. The current program is to do a VT-3. Our experience with boiling water reactors is that a VT-3 will not discover the type of cracks that you can get from IASEC and, therefore, an enhanced VT-1 examination is going to be required for the limiting component or limiting locations in the internals.

The licensee has taken this to heart, finally, and they have identified the inside surface of the re-entrant corners of the core barrel as a location that is going to be VT-1 -- enhanced VT-1 inspected. That has the highest combination of stresses, because it's a welded corner. It's the closest to the core and it also has high temperatures. On one side, it has the hot leg temperature; the other side, the cold leg temperature.

That takes care -- that's the stainless steel and welds. Now, we're also concerned about the cast stainless steel components. There are two cast stainless steel components. The CE shroud assembly tubes and the core support columns.

In this case, we are concerned about two things; thermal embrittlement, like I said, and the neutron embrittlement. There is no data available for this type of problem. So, again, we asked the

licensee to do an analysis or to do the VT-1 inspection, enhanced VT-1 inspection of these components.

Now, the analysis is -- this is how we're running the -- this is how we're doing -- we asked them to do the analysis. We established criteria for neutron fluents; that is, ten to the 17th neutrons per centimeter squared.

If the fluents receive, at the end of the license period, for any of these components, are above that criteria, it would be considered a high radiation area for the program and the only way the components would not be inspected would be if VT-3 -- would return to a VT-3 -- is if they could demonstrate that the loads on this thing during all ASME -- all accident conditions is either compressive or very low. Otherwise, if it has a high fluence, it would get an enhanced VT-1 examination.

The second part of the criteria is for low fluents components. If it turns out they have low fluents; that is, lower than ten to the 17th. In that case, we would think that the neutron irradiation embrittlement would not be a factor. The only factor to be considered then would be the thermal embrittlement.

There, they can go -- they would have to show that they meet the thermal embrittlement criteria we talked about and we modified for the cast austenitic stainless steels. If they could show that, then the inspection could be reduced to a VT-3.

That's our modification there.

The next program is the alloy-600 program. This is for the primary system. The alloy-600 program is a program to manage primary water stress corrosion cracking for pressure boundary components and it looks like the most susceptible, most safety-significant components.

This is an existing program. It basically ranks the alloy-600 components based upon the residual and operating stresses, operating time, and material heat treatment. It turned out, as part of this review, that in Unit 1, the most susceptible component is the vapor space instrument nozzle in the pressurizer -- four vapor space instrument nozzles in the pressurizer heads, and they will be replaced during the -- with alloy-690 during the 2000-year outage.

In Unit 2, it turned out that the limiting, most susceptible material was the pressurizer heater sleeves, and these materials were replaced with 690 in the 1989-1990.

The alloy-600 program has not identified any other -- at this time, any other materials that need replacement. The alloy-600 program, we use VT-1 and VT-2 to detect leakage and to determine whether there is a problem with the alloy-600 -- the other alloy-600 components.

The fourth, the last program I was going to talk about, which we discussed already, was the fatigue management program for the primary system. The fatigue monitoring program tracks the low cycle fatigue usage of critical reactor coolant system components.

The program has been modified to include reactor coolant pumps, motor-operated valves, some pressurizer components, control of drive mechanisms, reactor vessel level monitoring system components.

DR. SHACK: The other slide said there were no open issues.

MR. ELLIOT: I know. That's not true.

MR. FAIR: Could I help you with that? It's just the way that the -- we constructed the SE. As far as the program itself, we didn't have a problem with the way it was being implemented, and that is, tracking the worst components and taking corrective actions.

In terms of the open items in this section, they haven't completely evaluated all the components to determine if there were other locations that needed to be monitored. So that's one of the open items.

MR. ELLIOT: We have several open items. Some of these may require modifications to the in-service inspection program. The first one is that -- this is not a modification, but that the applicant should credit tech spec limits of steam generator leakage as part of its aging management program. That's just we think that that should be done.

We think there is a program needed to manage stress corrosion cracking of the reactor pressure vessel head closure seal leakage detection line. This line has had, in the past, stress corrosion cracking.

We think there is a program needed to manage the cracking of pressurizer heads and shelves, in particular, the cladding. We've had cracking in the cladding that has gone through the cladding into the base metal in Haddam Neck, around the -- and the area that needs to be looked at is the cladding around the surge nozzle and the heater welds. Those are areas that have high thermal fatigue.

DR. SHACK: When we say this, does this mean you want them to add to this to the fatigue monitoring program?

MR. ELLIOT: No.

DR. SHACK: Is that what is implied here?

MR. ELLIOT: No. In this case, we were negotiating what kind of inspection they can do to look and see whether or not we get any of the stress corrosion cracking of the clad in this region or thermal fatigue cracking of the clad in these regions.

The program that might need modification would be the ISI program.

Again, an ISI program is needed to manage cracking on the inside surface of small bore piping, including Inconel material. The applicant must document their inspection methods to detect where, before it begins to compromise the function of the hold-down rings.

DR. SHACK: Again, the small bore piping, that's piping that now escapes Section 11 because of its size. Is that the --

MR. ELLIOT: It doesn't escape it. It has just a surface examination. It doesn't have a volumetric, and so we don't see the inside surface. So we need something more.

We have a few confirmatory items. The applicant is to revise the cast austenitic stainless steel program to include the criteria and methods of examination recommended by the staff. The applicant is to revise the RPV materials surveillance program to include data and establish operating conditions for a period of extended operation, as I discussed.

The applicant is to confirm the applicability of the alloy-600 CEDM program through the period of extended operation. They have done the analysis for 40 years and now they have to confirm that the analysis is bounded for the 60 years.

The applicant should document their conclusion that the control element shroud bolts do not perform a safety function, as described in 10 CFR 50.4, and, therefore, not subject to aging management review. And the applicant is to document the operating stress for hold-down ring, to demonstrate that the hold-down ring is not subject to stress relaxation.

The final thing is you talked about fatigue. We have this as a confirmatory item. This is the environmental effects as related to GSI-190 and the applicant must resolve the environmental fatigue issue for the period of extended operation, if the issue is not resolved generically prior to the end of the current license term.

To summarize the license renewal issues that are critical for the vessel internals and reactor coolant system or internals embrittlement, which I discussed. Thermal aging of cast austenitic stainless steel, which I discussed. Vessel surveillance, which I discussed, the materials surveillance program, and fatigue is the fatigue monitoring program.

That concludes my discussion.

DR. FONTANA: Thank you.

DR. SHACK: I guess I didn't quite -- is the implication of the bullet on the fatigue really that that one can stay open for a long time yet and you don't really need to resolve it until the end of the current license?

MR. FAIR: Yes, that's correct. What we're relying on in that is we did the evaluation for current operating license, the 40-year evaluation, and we presented a finding that we didn't think we needed to backfit anything for the current operating license.

The open issue was whether we could extend that conclusion into the renewed period of operation and we thought we needed additional work in order to make some safety conclusion in the renewed period.

MR. GRIMES: I'd like to add. The treatment of this generic safety issue is the same approach that was used during the operating license stage in terms of the treatment of generic safety issues and recognizing that we weren't making a licensing decision at this point, with a pending issue unresolved.

It is our expectation that the work that the Office of Research is doing is going to identify a resolution of this issue well before the plant reaches the end of the 40 years.

It is a unique generic safety issue in that respect because we didn't have any other generic safety issues that bifurcated between 40 years and the period of extended operation.

But we've also recognized that we could tackle it on a plant-specific basis in much the same way that Barry described the way that we addressed these generic renewal issues for embrittlement and CASS and other things, on a plant-specific basis.

But at this point, we're just trying to reconcile what it's going to take to resolve the generic safety issue is where the NRC staff thinks it ought to be expending its energy rather than trying to resolve it on a plant-by-plant basis.

DR. FONTANA: Any additional questions, comments?

[No response.]

DR. FONTANA: Well, we're scheduled for a break now. Thank you very much. Let's be back here at 10:20.

[Recess.]

DR. FONTANA: We will resume the meeting. You had a 20-minute break instead of a 15-minute break, so we're going to make it up later.

MS. COFFIN: Bill, I just wanted to get back to you; later today, when we go over the cooling systems, you're going to hear a lot more about the aging management programs, for example, for the service water system. You'll see that ARDI is actually a very small component of the programs in effect for that system.

My name is Stephanie Coffin. I will be going over with you the engineered safety feature systems, which consist of the following three systems; the containment isolation group, the containment spray system, and the safety injection system.

Just very quickly, the containment isolation group functions to prevent uncontrolled or unmonitored releases. The containment spray system limits pressure -- the primary function is to limit pressure and temperature in the containment following an accident. The safety injection system, the primary function is to supply emergency core cooling following a LOCA.

Most of these programs you've seen before, because they are the common aging management programs that Cliff went over today. But very briefly, all three systems have some carbon steel, no alloy steel components, and because they're located in containment, they could potentially be exposed to concentrated boric acid. So to mitigate general corrosion of those components, and this is -- the applicant relies on its boric acid corrosion inspection program and we went over that earlier today.

With regard to the internals of these components, the containment isolation group has a variety of internal environments, including treated water, well water and gaseous waste, and because of the design of the system and the internal environments, the applicant presented information that the corrosion effects are expected to be minimal and they're relying on ARDI and supplemented by some local leak rate testing of some valves in their programs to verify that, for the management of aging effects. That would be crevice corrosion pitting, general corrosion.

DR. SHACK: What size is this piping that we're talking about here?

MS. COFFIN: I would have to look at the application. It probably varies. For the containment spray system, it's exposed internally to treated water and we're relying primarily on the applicant's chemistry program to mitigate the corrosive effects of that environment.

Because there are some stagnant conditions in the system, because it's in a standby mode most of the time, the applicant has committed also to doing some age-related degradation inspection, the ARDI inspections, to check specifically in those areas.

For the safety injection system, again, this system is exposed internally to treated water, and we're relying primarily on

their chemistry controls to prevent corrosion of the internal services.

There are some local leak rate tests and pumps and valves in their IST program that they also rely on to detect any degradation that's going on, supplemented by ARDI in some various portions of the system.

One aging effect that's actually not on this chart is elastomer degradation and that's for a perimeter seal on their refueling water tank, and the -- because it's exposed to the element, the applicant identified some degradation that is possible for that seal and they're relying on their structure and system walkdowns to identify that.

There are some modifications that they need to make to that program that I'm going to talk about in the next slide, because those are confirmatory items.

For the safety injection system, there is something unique in that system in that they have experienced, at this plant, stress corrosion cracking of the refueling water tank penetrations at the penetration welds and they've discovered that through their walkdowns. They plan on continuing that program to monitor -- manage that aging effect, although they're going to do some additional engineering evaluation, that, again, I'm going to put off just for a moment, because it's part of our confirmatory items with respect to that aging effect.

Lastly, fatigue, this system is included in their fatigue monitoring program and, once again, there is going to be a modification to that. The applicant is going to be doing some additional information relative to fatigue that I will talk to right now.

DR. SHACK: Would this thing see cycles or is this some sort of leakage kind of induced fatigue?

MR. FAIR: What they're monitoring right now is the safety injection nozzle, which does see thermal cycles during shutdown cooling initiation. They're also taking a look further in the line, certain sections of the line for potential stratification effects, which they haven't completed yet.

MS. COFFIN: There aren't any open items with respect to these three systems and the confirmatory items are, one, to modify the structure and system walkdowns and specifically what they're planning to do is explicitly add to the scope the inspections of the refueling water tank for the safety injection system. They're also going to add into the procedure inspection criteria for the perimeter seal for the RWT and for the RWT penetrations, penetration welds.

The applicant committed to doing an engineering evaluation of stress corrosion cracking at their RWT penetrations and they want to reach the conclusion that they feel satisfied that the walkdowns are sufficient to detect stress corrosion cracking before there is a loss of intended function. If they can't reach that conclusion to their satisfaction, then they're going to implement an ARDI-type inspection program for that particular aging effect.

Do you want to add something Barth?

MR. DOROSHUK: I want to make one comment. This is Barth Doroshuk, from BGE. Yesterday I referred to this engineering evaluation of SEC as a leak-before-break analysis, and I misspoke. That is an engineering evaluation, not a leak-before-break. So for the record.

MS. COFFIN: And the last confirmatory item, John spoke to this a minute ago, is that the applicant is right now reviewing industry reports, particularly with respect to thermal stratification for some portion of this system and to see if and how the fatigue monitoring program needs to be modified, particularly for this system, to ensure that fatigue is managed for the safety injection system.

With that, that takes care of these systems.

DR. UHRIG: Could you expand a little bit on -- I think it's called thermal fatigue.

MS. COFFIN: I would love to. John?

MR. FAIR: What did you want me to explain?

DR. UHRIG: The thing that I'm most familiar with is stress.

MR. FAIR: Yes, and that's what is being monitored.

DR. UHRIG: This is just basically thermal cycling reduces stress, but now you're talking about thermal stratification, and this has got me confused.

MR. FAIR: Well, there's an issue that came up with potential stratification in lines due to leakage through check valves and there was a bulletin issued on it, it was Bulletin 88-08.

A lot of licensees have gone back to look and see if they have this problem in any of the systems in their plant and the stratification problem is a combination of stratified flow and cycling flow due to leakage and circulation in certain parts of these systems.

They do cause alternating stresses, quite a number of cycles of these alternating stresses and can result in cracking and eventual leakage.

DR. UHRIG: I had an associated stratification fatigue.

MR. FAIR: It oscillates.

DR. UHRIG: I see. All right.

MR. FAIR: The stratification can cause other problems.

MR. PATNAIK: I'm Pat Patnaik. In answer to your question, Bill, about the size of injection containment spray piping, they're all six inches. They're over four inches and they're up to 12 inches diameter, stainless steel.

DR. FONTANA: Okay. Anymore questions, comments?

[No response.]

DR. FONTANA: Thank you.

MR. HOU: My name is Shou-Nein Hou, NRR. I'm the reviewer on Section 3.4. That covers three areas; the chemical boron control system, the compressed air system, and fire protection.

For the chemical and boron control systems, the major component consists of piping, accumulator, strainer, tank, flow, temperature, heat exchanger, and various kinds of valves.

The material, essentially it's stainless steel inside; on the inside. That means the contact of process flow. Outside, they do have carbon steel, alloy or stainless steel.

Another is compressed air. The material, it's carbon steel, and inside is the compressed air. That is enclosed instrument air, plant air, and standby saltwater air.

The major components, as you can see, are piping, accumulator, air compressor, and various valves. Now, another area is

about fire protection. In the license review, there are 66 systems and components, and 42 of them relate to the fire protection function.

In these 42 systems, 26 are safety-related structures and systems, such as the pressure boundary system and the structures to perform the fire barrier functions, and also some electrical equipment.

So in this section, we're only talking about the remaining 16 systems. Now, in these 16 remaining systems, nine -- part is safety-related and part is non-safety-related. But for safety-related, there is also another 26 I just mentioned, all be addressed separately in other sections about the aging management.

So for this particular review, only those non-safety-related portions of these 16 systems.

First, we talk about the chemical boron control system. Not because we have that operated as it inside the component, so there is a generic corrosion concern. So water chemistry program is very essential. I think that's one of the common improvements that we have discussed this morning and that essentially is just a program to identify the perimeters need to be monitored and also the frequency and also what's the acceptance limit. If you're beyond the limit and what kind of action need to be taken.

So that would take care of that generic corrosion inside those components, contact with the borated acid.

Now, in case if there is a leak, because the fastener is -- it's carbon steel and alloy, which are subject to corrosion effects to the borated acid. In that, they have borated acid corrosion inspection program. That's also been discussed in this morning.

Now, the plant also -- this system also has a unique concern is about using the heat trace to maintain the temperature of the systems above their limit to avoid saturation of the borated acid. That's about the stress corrosion cracking, stress corrosion cracking caused by the heat tracing. Because it contains hydrogen, which is a corrosive element.

Now, the licensee have a plant modification to remove this. That program being started in '91 to replace it with a non-corrosive one, and the program is still ongoing, and we were told that it would be completed by the end of the current licensing period.

I think that will take care of the stress corrosion cracking concerns.

Now, there are various valves. The valve seat and the disk is subject to wear, because it's normal operation. For that, they have a leak rate testing and that's a part of the plant surveillance test procedure.

So attention to all this. Now, they also supplement by an ARDI program. The ARDI program for these particular system, it try to verify no severe previous corrosion impeding internals of the components contacting the boric water and the shear side of the heat exchanger. That essentially is kind of walkdown process and it's been discussed in the morning.

Another is no significant vibration fatigue. That, I had to go back to the slide in here, talk about CVCS fatigue, the problem. Now, we know fatigue is a problem. It has two kind of concerns. One is

low cycle fatigue, one is the high cycle fatigue.

The low cycle fatigue is about the thermal transients and the cause of stress, fluctuation, and they have the fatigue monitoring program and we know this program, as present earlier, and that program is not complete yet. The place, the location for the monitoring, critical locations, has not been finalized.

Also, there are generic concerns also being discussed, the GSI-190, how to categorically qualify operating plant for the 60 years. Use the statistical approach, not risk-informed, to pick up sample from five PWR and the two BWR plants and perform an analysis using the modified curve generated by Argonne.

Now, besides that, now, there is a concern about the charging pump. The charging pump has created the operational vibration and that caused the cracking of the pump or block and also the suction side of the piping, as well. That has been -- that problem is being identified and also they have plant modifications in the design and also improve the pump operating practice. So the problem essentially is resolved and we're told about all this resolution and we agree with it, except for that information not yet being shown in the application.

So the application needs to be modified to incorporate that information. That essentially covers one of the confirmatory items.

DR. MILLER: When you say that problem is resolved, how do you reach that conclusion?

MR. FAIR: This is John Fair, again. What occurred on the CVCS system is early in operation, they had some vibration problems on the suction side that led to some failures. They went in and corrected the design, changed the design, changed the thickness of the piping, did some monitoring of the system, determined that they had an adequate fix for the --

DR. MILLER: How did they determine that?

MR. FAIR: That they didn't have significant vibration.

DR. MILLER: Do they have on-line vibration monitoring now?

MR. DOROSHUK: This is Barth Doroshuk, from BGE. We do have a maintenance condition monitoring program. That is a vibration monitoring program. It monitors systems throughout the plant. That program was most likely used in the verification corrective action follow-up after these modifications were done to the supports and to the piping to make sure that vibration was insignificant, as well as understanding or not seeing any additional failures or degradation in the system. We concluded that vibration was not plausible for this system.

DR. MILLER: How did you determine it was not plausible?

MR. DOROSHUK: Vibration, we believed that vibration is a result of an installation or design defect and the design defect or installation defect was corrected here through a plant modification and then verified through follow-up monitoring.

DR. MILLER: Okay.

MR. DOROSHUK: So in this particular location, vibration, we believe, is not an aging effect.

DR. MILLER: When was this done? I've looked at your SER, but it doesn't tell me a timeframe.

MR. DOROSHUK: Fifteen to 20 years ago.
DR. MILLER: So you've got that much experience.
MR. DOROSHUK: Yes, sir.
MR. FAIR: Just to clarify what the issue was on this. Originally, they proposed to do an ARDI on this piping to verify they had no vibration fatigue damage. There was a question as to how an ARDI was going to verify this and after some discussions, it was determined that since they had so much operating experience on the system as modified, that it really wasn't plausible at this time.
DR. MILLER: Part of this is response to Generic Letter 88-14. Is that what I'm reading here?
MR. FAIR: I don't believe so. Where are you reading?
DR. MILLER: I'm just reading the SER, on the overall problem that came up.
MR. HOU: You mean Generic Letter 88-14?
DR. MILLER: Right, Generic Letter 88-14.
MR. HOU: I'm going to talk about that later.
DR. MILLER: You're going to talk about that one.
MR. HOU: Yes, right.
DR. MILLER: That relates to instrument air, which apparently --
MR. HOU: That's right.
DR. MILLER: -- stimulated -- did that stimulate the vibrations?
MR. HOU: That is not a vibration problem.
DR. MILLER: Okay.
MR. HOU: Not a vibration problem. That's a -- well, I'm going to talk about it. Are you finished?
MR. FAIR: Yes.
MR. HOU: About the compressed air system, the inside is compressed air. Now, the material is carbon steel. That carbon steel can only cause corrosion concern if the air has some problems; for instance, it contains the moisture. So they have a preventive maintenance program. That program is going to check the air quality. But that program is later on being in place after it caused the piping failure problem and the failure is caused by the corrosion.
Because of that -- well, this is not only the plant problem, it also is the industry-wide problem. So the NRC issued Generic Letter 88-14. Because of this letter, they modified the plant and also changed the maintenance procedures and also they put in place the checklist to ensure that the air quality inside the instrumentation is dry and free of oil, free of the particulates, particles.
DR. MILLER: So there is a monitoring system for that.
MR. HOU: A monitoring system.
DR. MILLER: Generic Letter 88-14 spoke to that.
MR. HOU: 88-14 probably -- it's asking for some actions, but also providing information. This is an information letter. But with that, they performed a corrective action to try to resolve the problem, and this is what they do. So the problem no more exists.
And as for the plant air, and others, like saltwater, they do not have the air quality control, but, however, due to their

preventive maintenance procedures, they look at more frequently and also they do have certain filters, dryers, to make the air quality good. But -- except they do not have to monitor it. Quality monitor the instrument air.

But recently they have looked on those plants and see how the condition look like and find out those lines are in very good shape. So it look like it's not much a concern.

Now, talk about fire protection. Now, the fire protection, they actually -- they perform a certain way procedures, try to manage the aging problem. The first, in the updated FSAR, it has to be reviewed by the staff and we accept that, there is a fire protection program in there.

That contains certain systems and the components to ensure they have -- maintain its function and for the fire-fighting -- for the fire protection purpose.

And if -- for the non-safety-related components of the 16 systems fell into this category and there is not a problem. Now, in particular, what -- for example, that includes the feedwater, auxiliary feedwater and also the plant drain and also something, I guess, sprinklers and also hose stations.

Now, another screening, there's about a structural system, actually it's a monitoring the operating conditions of the system and component and that's by walkdown, periodic walkdown, and also by monitoring their performance during the plant operations.

So if have this covered, we know there is no problem because the operating condition for those system and components actually -- the fire-fighting capability, because in the safety-related components, we have -- now, there are other concerns, like LOCA, like seismic, but for this non-safety-related, they do not have -- for the operating loading is already large enough.

So if the operating condition is good, we know their fire-fighting capability is maintained.

Now, that kind system, for example, component cooling and compressed air system. Now, another approach they're taking is those systems -- now, they have part of it is safety-related, but also another portion is non-safety-related. Now, for safety-related, we know they have aging management programs defined, but in a non-safety-related, they have the same material, subject to the same environment.

So if they apply the safety-related aging management, the program, to this non-safety-related portion, that will take care of the aging concern. So this is that their third approach.

Now, with all of these three approaches, they also, they have supplemented by an ARDI. The ARDI program is one-time inspection, just to verify those fire protection non-safety-related portions, there is no significant general corrosion.

Now, with all these three approaches taken, that covers the 15 of the 16 remaining issues just mentioned, the non-safety issue, but there is one remaining one. It's the condensate system. The condensate system, the non-safety-related portion, the makeup line is downstream of a normally closed manual isolation valve. But that can take care of by the ARDI.

Now, talk about open items. Now, earlier, in my discussion on the component -- the CVCS, I mentioned about there is a concern on the stress corrosion cracking and the caused by the heat trace adhesive and they going to replace it with a new material.

But this replacement, it is started in 1991 and they said they're going to conclude it by end of the current licensing period. That means more than ten years away. If we know this is a concern and also we know that there is a way to fix it and also it's being started, so why take so long to finish, and that's one of our open items. We want to have reasons.

Another one of concern is within -- for this program, because it takes so long, and also because of the replacement, but we have to know what is the situation of the piping, would it already have a crack or they may generate cracks during the ten years period of time.

So we'd like the program also to consider the inspections to ensure that the condition of the piping. That's another open item.

Now, the third open item is about the fatigue. The fatigue, about in the -- in the low cycle fatigue, they have some -- they monitor the thermal transient and they perform analysis based on monitor of the results. But the analysis, the evaluation scope, it also include heat exchanger and thermal, is what they indicate in application. But in the application does not provide a detail about the process how to conduct this evaluation. So this is the third open item.

That concludes my presentation.

DR. FONTANA: Any comments? I guess one question for BG&E, which I guess they don't really need to answer, is when you get asked for what's taking you so long, what kind of answer do you give?

MR. HEIBEL: This is Dick Heibel, from Baltimore Gas & Electric. What we were doing with the installation on the boric -- the heat tracing on the boric acid, we're replacing it as components are pulled out for maintenance and on a catch-as-catch-can basis. It's a type of modification that, quite frankly, on its face, did not merit a -- it's very expensive program to undertake.

So what we have is stocks of this different type of heat tracing and when we pull pumps, valves, and do work on sections of pipe, replace it on a catch-as-catch-can basis, or if the heat tracing fails.

DR. FONTANA: All right. Thank you.

MR. HOU: Do you have anything to say about it?

MS. COFFIN: I would just add the comment that the application has seen stress corrosion cracking of these tanks due to the heat and that's why identified the problem, and I'm sure they have an engineering evaluation of why they can wait, but the staff hasn't seen that yet.

DR. FONTANA: Okay. Who's next?

DR. SEALE: Dr. Powers will probably be here the next time you talk about fire protection, so you may have a few questions to come up at that time. You're not off the hook.

MR. GEORGIEV: Good morning. My name is George Georgiev, and I'm with the Materials and Chemical Engineering Branch, with the Division of Engineering, and I will be doing the presentation of Section 3.5.

Section 3.5 includes four systems; component cooling systems, saltwater system, service water system, and the spent fuel pool cooling system. All these systems have in common, in general, the low temperature and as the name implies, they provide cooling to various equipment components within the plant.

The license application reported that several operating problems have occurred with those systems and with all fairness, they are all normal kind of problems that have been in other plants. An example of those problems, they had a leaky valve, valves in the component cooling system, they got some degradation of cement in the saltwater system, some high cycle fatigue in the spent fuel systems, and all these problems have been addressed and the repaired and there haven't been any other problems.

The materials of all this system are various because they all operate under various conditions. They include carbon steel, stainless steel, carbon-nickel, you've got various type of linings, rubber linings, cement lining, and all this is necessary to do the operation.

To address the problems and to take care of various degradation mechanisms, the application reports aging effects and for the purpose of this presentation, if you see here in the first where it says corrosion, that includes various type of corrosion. It includes crevice corrosion, pitting corrosion, galvanic corrosion, general corrosion, and the microbiological induced corrosion.

Also, there are other specific for these systems, degradation mechanism like wear, selective leaching, elastomer and rubber degradation, mortar, cement lining degradation, and sulfur.

DR. SHACK: A question. I thought yesterday they said they had rubber-lined systems, and you say cement.

MR. GEORGIEV: Yes, they do have both. They do have above-ground piping, cement lined. In fact, they have reported some leakage with this. I believe it has been replaced. But one has to address all these effects, the licensee has identified aging management program and most of them are existing programs. They are either site director procedures, programs to -- maintenance program items, and in some cases, they had to modify to address the aging effects.

And the only problem for this particular four system is the ARDI program, which is the inspection program that they'll do to look specifically for aging degradation, for these systems.

And as far as having open items, we don't have any open items and we don't have any licensing issues.

That concludes my presentation.

DR. FONTANA: Any questions, comments?

[No response.]

DR. FONTANA: Very good. Let's move on then to --

MR. GEORGIEV: Give my time for somebody else.

DR. SEALE: That's generous.

DR. FONTANA: Get out the heating ventilation and air conditioning systems.

MR. CHENG: My name is Tom Cheng, with the Mechanical and Civil Engineering Branch. Today I'm going to discuss something about

Section 3.6, the HVAC systems.

My presentation is going to cover three systems, which are the auxiliary building heating and ventilation system, primary containment heating and ventilation system, and the control room HVAC system.

Before I start my presentation, I would like to highlight some operating experience identified at the site. Some cracking has been discovered at the HVAC ducting due to vibration-induced fatigue. Some losing fasteners has been experienced because of the dynamic loading. The control room air conditioning unit was placed out of service to repair the broken damper linkages. Also, during the performance period, the elastomer degradation being identified.

BG&E, based on their operating experience and the review of industry documents, so identified those five aging-related degradations can cause possible aging effects, which is corrosion and elastomer degradation, effect of dynamic loads, and the wear of valves and radiation damages to the non-metallic material.

BG&E uses five aging management programs, as are listed in my viewgraphs. The first one is the structure and system walkdown procedures. I think that Dr. Munson already presented. Also, the ARDI, and he presented also.

Structure and system walkdown procedures, which is existing, the ARDI is a new one. In addition to those, BG&E also uses containment leakage rate testing program. This program would be used to discover and manage the leakage of surface wear and also the leakage of crevice corrosion, due to crevice corrosion, general corrosion, degradation.

Also, preventive maintenance program, which is existing program, to be used to discover and manage the effect of corrosion problem.

The third -- the fourth one is the administrative procedure -- I'm sorry. Excuse me. The chemistry program procedure, CP-206, to be used to identify the corrosion. I have to apologize. I forgot to list this one on my viewgraph.

BG&E has demonstrated in their application that the combination application of this aging management programs can provide a reasonable approach to inspect and assess the condition of the systems such that any degradation condition will be identified and documented and corrective action can be taken before the degradation proceeds to failure to perform the intended function.

The staff who reviewed BG&E's application drew the following conclusions. BG&E's approach for determination of possible aging effect and approach to identify possible aging effect are reasonable and acceptable.

The combination application of this aging effect program, management program, meets the ten elements of the SRP. I did not identify any open items, except one confirmatory item.

According to the application, the two new diesel generator buildings and also associated HVAC are placed into operating in 1995. Because the aging of the existing control room HVAC system equipment is some 20 years ahead of the aging of those located in the diesel generator building and also because the new equipment is just at the

beginning of its design life and the system have the design life of 45 years, BG&E concludes that the aging management of the new equipment can be deferred.

BG&E's conclusion is acceptable, providing BG&E needs to confirm that, the environmental conditions such that the moisture contents in the air, temperatures and so forth in the two diesel generator buildings are similar to the conditions in the control room and that the material and hardware configuration of the HVAC system located in the new building are similar to those in the control room.

This concludes my presentation.

DR. SHACK: What's the nature of the dynamic loading? This is the vibration-induced?

MR. CHENG: That's just, for example, like accumulators in a location and create a vibration, like a fan, those things.

DR. UHRIG: Imbalance.

MR. CHENG: Imbalance, correct.

DR. FONTANA: Any additional comments?

[No response.]

DR. FONTANA: Thank you very much. We'll move on to emergency diesel generator systems.

MR. GEORGIEV: Hello again. Since we are formally introduced already, I'll skip the first slide and go to the second one. The emergency diesel generator system actually includes two systems, the diesel generator itself and the diesel fuel oil system.

In general, the diesel has been operating adequately and several problems have been reported, but all of them have been addressed and resolved by BG&E.

The operating condition for the diesel basically is external environment, which is plant quality type of air, and internal environment, it's either water, tritiated water, or oil, or exhaust gases coming when the diesel is operated.

To address the degradation mechanism associated with diesel fuel oil, the application basically divide the problem into external piping and buried piping, and materials involve the carbon steel materials and for the buried piping, the buried piping has been wrapped with protective coating and they also use cathodic protections to protect the buried piping.

For the external service of the piping, they are protected by paint. In essence, what BG&E reports to do to address the degradation mechanisms, which are corrosion, weathering, fatigue, and wear, they have existing plant programs and also are creating four other new programs, which are a program which is catching all type of problem, the program to inspect the buried pipe, and a program to inspect the balance for the fuel oil storage tanks and they also have created a new program for caulking around the storage fuel oil tank. The reason being to prevent water and other material to seeps and effect the metal.

We have, in essence, agreed with BG&E's proposal to manage the aging effects. However, we do identify one open item and this open item pertains to BG&E has classified the cathodic protection as not being needed for aging management of buried piping. The staff disagrees with this. We believe that they do need both. They do need the

protective wrapping measures and also the cathodic protections.

License renewal issues, we don't have any. We have no confirmatory items.

That, in essence, concludes my presentations.

DR. FONTANA: Any comments?

DR. UHRIG: Does the cathodic protection --

MR. DAVIS: It's a compressed current system, but it acts the same way.

DR. FONTANA: Thank you. I guess we can go on to the next item before lunch. It looks like it's fairly long, but we scheduled 20 minutes for it.

Moving on to the steam and power conversion systems.

MR. PARCZEWSKI: My name is Kris Parczewski. I am a member of staff of Material and Chemical Engineering staff, in the Division of Engineering.

I'm going to present to you a review, staff's review of steam and power conversion systems. The steam and power conversion systems included in the license application, license renewal application consist of six systems; auxiliary feedwater system, feedwater system, main steam system, steam generator blowdown system, extraction steam system, which, by the way, is inoperable, and nitrogen/hydrogen systems.

Now, the system, the material, the materials of the system are mainly carbon steel, but some of the systems have some additional material. For auxiliary feedwater system has, in addition to carbon steel, alloy steel, bronze, brass, cast iron, and elastomers. It is exposed to an environment of chemically treated water at temperatures just below 200 degrees Fahrenheit.

DR. FONTANA: Excuse me. Could you push that other microphone out of the way? Thank you.

MR. PARCZEWSKI: The feedwater system, in addition of carbon steel, has chrome alloy steel. It is exposed to an environment of chemically treated water, the secondary water, basically, at a higher temperature, up to 475 degrees Fahrenheit.

Main steam system, in addition to carbon, has alloy steel and some stainless steel, and the orifice is made out of stainless steel. It's exposed to an environment of wet steel and two-phase fluid in the drain line when the condensation occurs.

The steam generator blowdown system has, in addition to carbon steel, stainless steel, brass and cast iron. It is exposed to an environment, two-phase fluid on the side of the heat exchanger and the component cooling water on the tube side of the heat exchanger.

The extraction of steel is made strictly from carbon steel and it's exposed to the moist air. It's empty, because it's not being used presently. The nitrogen and hydrogen system is made out of carbon steel and it is exposed to an environment of very, very dry gases, with dew point minus 40 degrees Fahrenheit, which is extremely dry. But still it might have some corrosion, so the applicant included it in the review.

There are several different aging mechanisms, aging effects. The most prevalent definitely is the corrosion and there are several managing -- aging management programs for different systems, depending

on the operating conditions and the type of material and so on.

There are really two types of aging management programs. One is a preventive program and the other one is monitoring. The preventive program, in most cases, as you can see here, is controlled with secondary water, there's pH, oxygen consideration, some iron, boron, if there is boron in the system, and so on.

DR. SHACK: What do they use for their pH control agent?

MR. PARCZEWSKI: They use -- for pH control, they use the hydrogen, which, of course, is composed in the heat exchanger, the high temperature. You generate some ammonia, which keeps pH.

In the auxiliary feedwater system, in addition to secondary water, there is a buried pipe inspection program, which is -- pipe are exposed to MIC, microbiologically influenced corrosion, and there is no way to control it. The only way to prevent it, the only way is just inspecting it.

The second one is, of course, preventing maintenance. Corrosion inspection, this is a new program, ARDI program, they do corrosion inspection.

In feedwater, again, there is a corrosion inspection program, which is the new ARDI program. In water, main steam line, main steam system, the secondary water, to some extent, prevents some corrosion. This is the only way we can do it.

DR. SHACK: In the feedwater system, what is the ARDI looking for here?

MR. PARCZEWSKI: The ARDI is looking for damage due to corrosion, inspection.

DR. SHACK: So there is no regular erosion/corrosion checkmate type program.

MR. PARCZEWSKI: There will be another point in my presentation on erosion/corrosion. It's a specific type of corrosion, which is not included in the corrosion. We did it separately because there is slightly different control of this particular mechanism. It's the next slide.

In the steam generator blowdown system, we have already secondary water chemistry. Then there is, of course, another component, cooling water, which controls the chemistry of the cooling water in the heat exchanger, the one which goes through the tubes, and there is an additional corrosion inspection ARDI program.

In extraction steam, there is an ARDI program for control -- for inspecting the corrosion in this extraction system, which I indicated really has only moist air. In nitrogen/hydrogen system, you have motion control, which is really inspecting, but if there is any corrosion, it's extremely small, because the gases are kept in a very, very dry condition.

Now, erosion/corrosion. Erosion/corrosion is a very, very significant aging mechanism and this is why we looked at it as a separate item. It is, to some extent, controlled -- prevented by controlling secondary water. However, there is a problem there. Usually to reduce corrosion, you keep oxygen down as much as you can. It is not true erosion/corrosion.

To optimize, you have to go up to a certain point. You

cannot go completely -- usually, you should keep above about 40 ppb. Of course, you cannot do this. So really, in order to control corrosion, you cannot optimize erosion/corrosion system. Therefore, prevention using secondary water is somehow limited.

So we have, in addition to inspection programs, monitoring programs. One of them -- we have the chemistry -- we have a monitoring program which uses a program developed by EPRI and they have a check -- I have experience with that, an excellent program, and what it does, it predicts which components are susceptible to corrosion and in addition, it predicts when they're going to fail.

The program has to be, so to speak, calibrated, which means some of the components have to be measured, the effect of erosion/corrosion, by using the either ultrasonics or radiography, and then input into the code. This calibrated code then can predict some other components which are not measured, when they're going to fail, when they have to be replaced.

It's being used by practically all the licensees, because it does a very good job.

In addition, there is an ARDI program for inspection which basically is an extension of this monitoring program, using the same program, but it adds additional components which originally were not included in the program. So basically, it's an extension of the E/C program.

This is for -- in main steam line, again, you have secondary water chemistry monitoring, basically the same programs as for water -- in feedwater.

The same applies to steam generator blowdown. Again, you have the same program. So all those three systems have the same program.

In addition, cavitation is another mechanism which, of course, is not a chemical. It doesn't involve corrosion. It's hydrodynamic phenomenon, and there is an -- there is going to be established an ARDI program for inspecting cavitation damage. There is no way to mitigate -- to prevent it. Just the only thing is to inspect it.

This same applies to the wear program. ARDI inspects the control of seats and plugs of steam atmospheric valves and sterite carbon steel borders and MSIVs. So this program will be limited to those components.

Now, the steam generator blowdown system would have a leaching mechanism. There are some components made out of cast iron or made out of brass. In those components, the environment, corrosive environment removes selectively materials in case of cast iron to remove the ferrite phase. In the case of brass, it removes zinc. So this is the corrosion mechanism.

Again, there is no -- you can control, to some degree, through secondary chemistry, but it still needs to be inspected and there is inspection program, ARDI inspection that is going to take care of it.

Now, elastomers, there are two programs addressing the elastomer degradation. One program, which is the sealant inspection

program, will take care -- again, you cannot prevent the program. The only thing is to inspect it.

The sealant inspection program, which inspects the sealant around the condensate storage tank, which might be affected by the environment. ARDI elastomer program, which will address the inspection of solenoid operated valve made of ethylene, propylene, and subject to wear. So that's the programs.

The final is fatigue. In some of the piping in feedwater, you have stratification of fluid in the pipe and this stratification would produce thermal stresses which will obviously produce some fatigue of the piping. So this is the final program I will be discussing here.

DR. SHACK: John, just a question on that fatigue. You need a horizontal run of piping to have that problem, don't you?

MR. FAIR: Yes. As a matter of fact, that's why they selected this section of the pipe, right near the nozzle. We asked a question as to why it wasn't a concern anywhere else and it was because there is a vertical riser coming up to that horizontal run of pipe.

DR. SHACK: So there's just one sort of small segment of horizontal piping here.

MR. FAIR: Yes, and this is an area where they have a fairly detailed monitoring of the thermal temperatures in the area to do a detailed fatigue analysis.

DR. FONTANA: Any additional comments?

[No response.]

DR. FONTANA: Thank you very much. I think we'll move on to the next topic, sampling and monitoring systems.

MR. PATNAIK: I'm Pat Patnaik, from the Division of Engineering. I've been asked -- I compiled the sampling and monitoring system Section 3.9. This sampling and monitoring system comprises of nuclear steam supply sampling system, radiation monitoring system, and the instrument lines.

Mine is going to be a snapshot of the SER. The nuclear steam supply, NSSS sampling system provides for sampling of liquids, steam gases, radioactive and chemical control of plant fluids, and this has five subsystems, which is reactor coolant sampling, steam generator blowdown sampling, radioactive waste sampling, gas analyzing sampling, and post-accident sampling.

The general categories of equipment are accumulators, air drives, piping, valves, valve operated panels, instruments, sample vessels, and pumps. The materials for these components are stainless steel or carbon steel.

These are compatible with the medium inside the pressure boundary, which is either borated water or chemically treated water.

The components in this NSSS sampling system that we evaluated had the intended functions of maintaining the pressure boundary. It provides containment actuation of the nuclear steam supply sampling system during a LOCA. It also provides capability to sample gaseous fluid during an accident.

The RMS, which is the release and monitoring system, detects an increasing radiation level or an abnormal radioactivity concentration at selected points in the plant. It provides indication of such

conditions to operating personnel and the system monitors also the discharge of radioactive fluids from the plant and provides a signal to isolate components in the event of abnormal conditions, to prevent uncontrolled release to the environment.

Again, the RMS comprises of piping, tubing, pumps, valves, filters, instrumentation, and the materials are either stainless steel or carbon steel, and which are compatible with the internal environment which is either air, borated water, or chemically treated water.

They had intended functions of maintaining the pressure boundary. It provides containment isolation, radiation signal to the engineered safety feature actuation system for containment isolation and radiological release control.

DR. SEALE: Would you help me? I've got a block. What's the BACI, again?

MR. PATNAIK: That's the boric acid corrosion inspection program that you heard in the earlier presentation.

DR. SEALE: Okay. I knew I had heard it, but I had forgotten what it was. Somehow or another, I didn't feel comfortable.

MR. PATNAIK: This is the program that the in-service inspection personnel perform right after the outage and walk down the system.

DR. SEALE: Yes, okay.

MR. PATNAIK: Now, moving on. The instrument lines are associated with all plant systems. Therefore, the applicant evaluated this as a commodity. And for the purpose of instrument line, the evaluation is from the -- looks at from the process line down to the first hand valve or route valve. Then it went line-up to the instrument. In other words, it's defined as the components located downstream of the first hand valve off the main process line or the vessel, which is called the route valve, and the instrument lines are all piping, tubing, fittings, hand valves.

The materials are stainless steel, carbon steel, copper, depending on the environment inside, which could be borated water, chemically treated water, oil, air. The components that we evaluated had the intended functions of maintaining pressure boundary integrity.

Corrosion manifests as general corrosion of external, which is due to leakage of borated water from piping or joints. As the previous speakers well stated, the ARDI program is -- the licensee has taken credit for the ARDI program and the BACI program, boric acid corrosion inspection program, on the nuclear steam supply system sampling lines.

And for radiation monitoring system, also, ARDI program has been taken credit and on the instrument lines, again, we have ARDI program. Structures and systems walkdown, which you've heard.

Then there are two other programs that the licensee has taken credit for, which is control of shift activities and ownership of plant operating spaces.

I want to walk you through these last two, because you haven't heard anything of these two.

Under control of shift activities, operators perform the walkdowns, plant operators. They inspect accessible operating spaces

during each shift and when the containment -- when the -- during an outage, they also perform these walkdowns inside the containment, once per shift.

This program provides for discovery of conditions that could allow general corrosion to progress for the instrument line supports, by performing visual inspections.

The inspection items related to aging management include vibrations and effects that may have caused by this age-related degradation mechanism, such as damaged piping, instrument tubing, or leakage of fluids.

Also, this program would also detect leakage of fluids, which is as a result of conditions progressing from the age-related degradation mechanism. And the licensee also has the corrective actions program which will take care of any of these aging effects noticed during the inspections.

The other program is the ownership of plant operating spaces. Under this program, the plant operating spaces, they have owners identified within each space who would provide a point of contact for any individual who finds deficiencies or any concern with the space, and the responsible individuals are required to periodically inspect their assigned spaces for housekeeping, cleanliness, material conditions, and radiological deficiencies.

This program provides for discovery of general corrosion of the instrument line supports by performing visual inspection in plant operating areas.

Again, the inspection items related with this aging management include items related to specific age-related degradation mechanisms, such as corrosion; item two is effects that may have been caused by age-related degradation mechanisms, such as loose lines or loose fasteners, because of fluids, and the conditions of pipes, loose fasteners, conditions that would allow progression of age-related degradation mechanisms, such as unbracketed lines and pipes.

Again, they have the corrective action program which takes care of any deficiencies that they identify.

That's the general corrosion.

Next, we have this crevice corrosion and pitting. For the nuclear steam system, we have the ARDI program and then we have the other programs like specification and surveillance of the system, component cooling, service water, secondary chemistry program.

These are all the chemistry programs, which the licensee is taking credit for, as mitigation. Then the third is the local leak rate test of penetrations. Actual, this local leak rate test of penetrations is identifying where in the control valves, but the staff didn't evaluate aging management on the valve internals because the valve internals perform their intended function with moving parts and changes in the configuration, which is not subject to aging management review.

DR. SHACK: Would this local leak rate give you a thermal cycling problem and a fatigue problem?

MR. PATNAIK: Local leak rate --

DR. SHACK: Through the valve. Is this a hot/cold -- hot fluid going to a cold fluid kind of thing?

MR. PATNAIK: No. I'm talking about Appendix C test -- I mean, Appendix J, Type C test.

DR. SEALE: Okay. Which is --

MR. PATNAIK: Which is different.

I guess I have one more slide. Lastly, the low cycle thermal fatigue is one of the possible plausible age-related degradation mechanisms on the nuclear steam supply sampling system. Anytime you draw a sample, you go through a thermal cycling, and what the licensee has used fatigue monitoring program.

We have an open item on this, like many other fatigue items, items on fatigue, this item involves -- there are 11 locations in the RCS that are being monitored for fatigue and our staff thought that the applicant should provide validation to demonstrate that the low cycle fatigue uses of piping and valves in the RCS hot leg sampling is bounded by monitoring of those 11 fatigue critical locations. That was the only open item.

There is one other item, age-related degradation, elastomer degradation. The internals of check valves in the past, the post-accident sampling system gas return line tot he containment, and some of the supports in the instrument line. They contain the elastomer materials that are susceptible to age-related degradation.

The staff determined that the applicant's ARDI program will effectively manage this age-related degradation mechanism. So the staff concluded the applicant has demonstrated that the aging effects associated with the sampling and monitoring systems are adequately managed, such that there is reasonable assurance that the systems will perform their intended functions in accordance with the current licensing basis.

So this is a nutshell of what we presented of the ACR.

DR. FONTANA: Any additional comments?

[No response.]

DR. FONTANA: Well, thank you very much. The next item is a fairly long one, so I think we ought to break for lunch now. Since we're ahead of time, I guess we can show up at 1:00.

MR. GRIMES: That would be acceptable to the staff. As a matter of fact, we would prefer that, since the folks that are supposed to be here for the afternoon session might not otherwise know when to show up. So if we could reconvene at one, that would be our target.

DR. FONTANA: That's fine. Okay. We'll come back at 1:00.

[Whereupon, at 11:53 a.m., the meeting was recessed, to reconvene at 1:00 p.m., this same day.].

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

[1:00 p.m.]

DR. FONTANA: The meeting will resume. We'll move into the presentation on building structures. David Jeng.

MR. JENG: Yes.

MR. GRIMES: Dr. Fontana, before we continue with the staff presentation, I would like to mention that I just provided a copy of a staff position that was issued yesterday to NEI on fuses, which concludes that aging management review for fuses is not necessary.

Assuming that NEI does not object to the conclusion in that position or that we otherwise don't receive critical comments on the

basis for arriving at that decision, that will address one of the open items in the Calvert Cliffs review.

That letter also illustrates the process by which we're going through and defining these generic renewal issues and addressing the resolution and then documenting the results.

It describes the nature of the guidance that we would add to the standard review plan. So we offer that also to the subcommittee as an illustration of how the process is working.

DR. FONTANA: Thank you.

MR. JENG: Good afternoon. My name is David Jeng. I am with the Mechanical and Chemical Engineering Branch of the Division of Engineering.

Today, I am going to report to you our review findings of the building structures, which is covered in the ACR Section 3.10. Please go to page 75.

Building structures of BG&E include the following five items; primary containment structure, turbine building, intake structure, miscellaneous tank involved, auxiliary building, and safety-related diesel generator building structures.

The basic approach of BG&E in achieving aging effect management for their structures are as follows. They, first, identified all the structures and component types, such as the concrete structure components or steel structure components, and matching these types to the potential aging-related degradation mechanisms, such as the corrosion of the steel, cracking of the concrete, and corrosion of the stainless steel liners in the spent fuel pool.

By matching these two concepts, the component types, with the potential age degradation mechanisms, they come up with some ten structure and component types such aging type categories and I am going to report to you how these ten categories are identified and how their aging management programs are proposed to be handled.

Going to page 76. The first item is the corrosion of tendons in pre-stressing losses. BG&E, in this evaluation, determined that their aging management program for this item should include mitigation -- periodic tendon surveillance program and implementation of a long-term corrective action program, which was established after their discovery of the earlier degradations in the tendons group.

Going to the second item on the same page. Concrete reinforcing degradations. BG&E determined that the aging effect of freeze/thaw, leaching, aggressive chemical attack, groundwater, boric acid, and flow-in water do not apply to their concrete structures, except for the intake structure, which is submerged into a bay water, a more aggressive environment type water.

The reason for their judging that these effect do not apply because the concrete they provided is a very high quality concrete and their aggregate are tested to standards and also the design is such that they are consistent with the ACI process and they are going to ensure such effect would not prevail.

Please go to page 77.

DR. FONTANA: Are they also inspected at some point to make sure that that kind of construction standard really does -- those kind

of construction standards really does provide concrete that is that good?

MR. JENG: Yes. As I said in the slide, in the curing, which covers the good quality construction practices and the post-construction curing of the concrete.

Going to page 77. Weathering of the caulking, sealants and expansion joints. BG&E's aging management program items include for the fire barriers in the auxiliary building and adjacent rooms, they are going to implement an existing fire barrier program. For the other caulking and sealants which are non-fire barrier functioning, they are going to propose a new program to perform inspection.

But BG&E did not adequately cover the potential aging effect of radiation temperature on the non-metallic portion of the penetration assemblies, such as the cable installation, sealants for their penetration, and this item remains open, and this is listed in the open items later.

Please go to page 78. The corrosion of containment wall and dome liners. BG&E's evaluation decided that the program should include use of a protective coating to minimize corrosion effects, implementation of visual inspections. They are using STP-M-665 1/2 on the two plants, respectively.

And the last item that BG&E indicated that the -- based on their past experience, their inspection program has been shown to be quite effective.

Please go to page 79.

DR. SHACK: What is the nature of the periodic inspection?

MR. JENG: Okay. The most inspection is the type of inspection -- for instance, the containment liner inspection, which is based on the ASME IEW/IWL provision, as well as the Reg Guide 1.35, and they are done on every refueling outage.

DR. SHACK: But is that a visual inspection?

MR. JENG: Basically, visual inspections.

We are on page 79. Corrosion of steel. The aging management program lists item includes use of protective coatings to minimize corrosion. Again, implementation of a periodic visual inspection program. But for the containment emergency sump cover and screen, which is sort of unique, it was not specifically covered in the earlier BG&E maintenance program and they are proposing a new inspection program, number STP-M-661.

Going to the lower part of the page, corrosion of the refueling spent fuel pool liners and cavity sealing ring, but in 1995, BG&E did inspect the fuel transfer canal and ensured that there was no indication of damage or corrosion.

So for this item management, BG&E indicated that the concern is the potential IGSCC, which may be applicable to the stainless steel liners and the PCSR and for this item management, BG&E proposes to use a periodic walkdown, that's MN-1-319, to manage the aging effects.

Please go to page 80. The next item in the category is degradation of intake structure containing concrete walls, sluice gates, and steel subject to aggressive chemical attack.

The aging management program proposed by BG&E for this

category include use of a preventive coating to minimize steel components corrosion, implementation of periodic inspection, and performance of structure and system walkdowns.

The lower portion of the page, corrosion of steel components inside miscellaneous tanks involve enclosures. For this particular category, BG&E proposes to use preventive coating to minimize corrosion, implementation of periodic walkdowns, and through application of these programs, they intend to manage the corrosion of CST tank number 12, FOST tank number 21, and the auxiliary feedwater valve enclosure.

Please go to page 81.

DR. UHRIG: You said they propose to use. They presently have preventive coating, do they not?

MR. JENG: They do, but they are making it official commitment for some enhancement of the content of the program.

DR. UHRIG: Thank you.

MR. JENG: Please go to page 81. Weathering of vertical tendons. BG&E did discover some degradation in the vertical tendons. For this category, it proposes to include implementation of periodic inspection and to perform needed engineering evaluation and take whatever needed corrective actions. The staff finds this to be acceptable.

Go to the lower portion of the page. The evaluation of neutron absorbing materials. For this particular consideration, BG&E proposes to perform periodic sampling of the neutron absorbing materials and also to implement the EGP 86-03R title, analogies of neutron absorbing material in spent fuel storage racks.

Please go to page 82. Besides the about ten items I discussed, BG&E also looked into the potential effect of foundation settlement and it concluded, and the staff agreed to their conclusion, that because of the following three reasons, the foundation settlement is not a plausible concern for the BG&E structural foundations.

The number one basis is the design is such that the building capacity of the foundation material is so high, with a margin of more than ten. Secondly, there is the underground drainage system in place right now which would tend to control groundwater levels. And the third reason is the -- after all these years, the settlement, if any, should be mostly in the uniform settlement and the settlement normally do not effect the structure performance.

For the intake structure, BG&E did also maintain that the first and third reason alone should be able to justify that there will be no settlement concerns for intake structures. Incidentally, the intake structure of the underground drainage system.

I have covered the major, some ten component category aging effects and the BG&E proposed management programs. The staff did review all these proposed programs in great details and except for the open item which we have three items later, we have come to conclusion that they have done adequate evaluation job and proposed adequate scope of programs to achieve the needed management of aging effects of BG&E building structures.

Please go to page 83. There are three open items. The first one is pertaining to the tendon force trending analysis. Because

of the major difficulties experienced in the tendon areas, and the staff asked BG&E to show some trending of the existing forces in the tendons to stay above the minimum requirements called for by the design, at the end of the 60 years or 20 years extended period, and this is the first open item.

The second one pertain to the concern of the groundwater effect on the intake structure from the embedded surface areas and the BG&E presented some chemical analysis of the groundwater for the plant. In fact, they provided three reports. One of the three testing show very high -- concern on the degradation of the concrete surfaces.

So for this reason, the staff asked BG&E to commit to perform at least some portion of the inspection on the outside exterior surfaces of the intake structures before the starting of the license renewal period at least one time, and this is the second open item.

The third open item pertain to the BG&E need to further address the effect of aging due to irradiation and temperature on the cover, O-ring and other known metallic materials for the electrical penetrations.

Please go to page 84. There are two confirmatory items. The first one pertain to the BG&E commitment to perform inspection before year 2002 of the containment domes. There have been some freeze/thaw induced degradation observed on the top of the containment and BG&E maintains that -- but the staff wants to make sure, you do this inspect one before year 2002, and they consented.

The second item pertain to the BG&E commitment to further enhance the guidance on their MN-1-319, which is quite often used in many of the programs. The enhanced area covers, number one, to provide much more detailed guidance on how to judge the functionality of the structures and components.

The second item is to further enhance the guidance on how they can change -- the authority to change the programs, scoping decision criteria, and how to change the schedule of inspection.

So these two item BG&E has committed enhance in their program MN-1-319. There are six -- page 85, please. There are six license renewal issues. Most of these issues are not germane to BG&E because they already provided information specific to their plant and one item -- two items that staff has yet to develop their own position.

So I am reporting to you that the license renewal issue does not pertain to BG&E application.

With this, I am concluding my presentation and if you have any questions, I would be pleased to answer your question.

DR. FONTANA: Let me take time to look at these just for a second here.

DR. UHRIG: These issues will be resolved before -- these six issues.

MR. JENG: The six issues are not germane to BG&E's situation.

DR. UHRIG: Okay.

DR. FONTANA: Any comments? Any additional comments?

[No response.]

DR. FONTANA: Well, thank you very much.

MR. JENG: Thank you.

DR. FONTANA: Thank you. We'll move on to component support, cranes and electrical commodities.

MS. LI: I'm Renee Li, from Mechanical Engineering Branch, in Division of Engineering. The section I'm going to talk about is Section 3.11, which covers component supports, cranes and electrical commodities.

For component support, the component support is defined as the connection between a system or a component within a system and the structure member. All component support type that provide support to system and the components which are within the scope of license renewal are also considered to be within the license renewal.

The component support including piping supports, cable raceway support, HVAC ducting support, and equipment support. The support section also include the piping segments that provide structure support.

These piping segments include piping segments beyond the safety and the non-safety-related boundary to the first seismic restraint and they perform the intended passive function of providing structure support to the safety-related piping.

The crane section include fuel handling equipment and other heavy load handling cranes. This section covers the evaluation of, A, components involved in fuel handling and transfer and, B, cranes that routinely lift heavy loads over safety-related components that are associated with fire systems, spent fuel storage, refueling pool, elevator fuel handling and the cranes.

The last section I'm going to talk about is the electrical commodity. The electrical commodity include the structure enclosure for electrical equipment which provides support and protection of the electrical equipment located within them.

The electrical commodity include miscellaneous panels, motor control center cabinets, switch gear, disconnected cabinet, bus cabinets, circuit breaker cabinet, local control station panel, battery terminals, and the charger cabinet, and inverter cabinet.

The following three slides will show the applicant proposed aging management program to manage the aging effects and which will also show which components that -- component support that those aging management are credited for.

Our review is to ensure that the applicant's proposed aging management program will manage the aging mechanism and the effects in such a way that the intended function of the component supports will be maintained in accordance with the current licensing basis during the period of extended operation.

As you see, the aging management program for general corrosion of steel, which has combination of numerous program, and the most of the program have been addressed earlier. I think the only one maybe is the snubber visual inspection surveillance program, and that's the tech spec snubber surveillance program, which has a table that will determine the frequency and also the sample size of each inspection.

The other have been covered, except addition of baseline walkdown, which is to pick up those component supports that are not

covered by the original baseline inspection.

Preventive maintenance checklist. Usually, the PM checklist or the task is for a specific component or component support. For example, there is a preventive maintenance checklist that's a modified version of the existing program and it's credited for aging management of the metal spring isolator and the fixed basis component supports, such as containment air cooler fan.

The same program for the general corrosion of steel are used for managing the effects of loading due to hydraulic vibration or water hammer.

The next slide shows the aging effects of loading due to some extension of piping and the component, and aging management program basically are very similar to the previous one. The first one is the structure and the system walkdown. The second one is the control of shift activity. The third one is the ownership of plant operating spaces and also the section 11 ISI program.

The same program is also used to manage the aging effects of loading due to rotating machinery. The last slide for the component supports has to do with aging effect of elastomer hardening and the program -- the aging management program, the three programs we already discussed, plus the plant modification program, the plant modification program is a new program and that's credited for the modification of control room HVAC air handler support to replace elastomer isolator with the spring-type isolator.

The last aging effect is the stress corrosion cracking of high strength bolts and the aging management program that is credited for ISI and addition of baseline walkdown.

And for the piping segment that provides structure support, in the application, BG&E states that the same aging effect for the safety-related portion of the piping will apply to these piping segment beyond the safety and the non-safety-related boundary. Therefore, the aging management program that credits for managing the aging effects of safety-related portion of piping are also applicable to those piping segments.

The next two slides are for fuel handling equipment and other heavy load handling cranes. Again, our review is to ensure that the applicant's proposed aging management program will manage the aging effects in such a way that the intended functions of the components will be maintained in accordance with the current licensing basis during the period of extended operation.

BG&E has proposed numerous evaluation programs, procedures, instructions, and including PM tasks, and those programs have been used for different combinations of aging effects and the fuel handling equipment or the heavy load handling crane.

The aging effects they cover has general corrosion, oxidation, fatigue, and wear.

The next slide will show the mechanical degradation, distortion, and also corrosion due to boric acid. I will not go into the detail of the various PM programs.

This is the slide for the mechanical degradation, distortion, and also corrosion due to the boric acid.

Most of the programs that I just showed, they are existing programs. Just a few are the modified programs and the programs generally provide requirements for inspection. Most of the inspections are visual inspections, but they have some NDE, and each program is credited for discovery and management of certain aging effects for a specific group of components.

I think one of the programs, that is the boric acid corrosion inspection, this morning has been discussed and there are some specific concerns of that program.

DR. SHACK: Is the snubber considered a passive support or are you --

MS. LI: The snubber itself is active. But between the snubber and the structure, the portion we consider as a support to the snubber, is passive. So that is the one that's inside scope.

DR. SHACK: But the active function of the snubber is checked.

MS. LI: Is checked per the tech spec.

DR. SHACK: Under the tech spec.

MS. LI: That's right. The next two slides are for the electrical commodity. The applicant has identified the aging effects of fatigue and electrical stressor and the wear, also general corrosion and the dynamic loading on the motor panels.

As far as the aging management program, for the fatigue, the licensee credits the PM checklist, I think the name is reactor trip circuit breaker inspection, and that has a requirement of every 48 weeks, they do a visual inspection and also require that if any fatigue degradation is detected, it should be reported and they evaluate per site corrective procedures, and operating experience showed that this has been very effective.

Also, the program, ARDI is also credited for these aging effects.

For the electrical stressors, the PM procedure, MN-1-102, is credited and in accordance with the PM procedure, repetitive tasks are performed, train, inspect, and calibrate the electrical commodity, and if there is any degradation, it will be reported and they evaluate and correct action taken. Also, the ARDI program is credited for this aging effects and I think for the other two, for maintenance procedure and the ARDI, the dynamic load -- yes. The dynamic loading on the motor control center panel are the one that nearby the emergency diesel generator and the concern is the vibration.

The staff's review, we do not identify any open item or confirmatory item and also there is no license renewal issue in this area.

Based on the information provided by the applicant, we are able to conclude that the aging management program will be adequate to manage the aging effects identified by the applicant and we believe that there is a reasonable assurance that component support, fuel handling elements, heavy load handling cranes and the electrical commodity will perform their intended function in accordance with the current licensing basis during the period of extended operation.

That concludes my presentation.

DR. FONTANA: Any comments?
[No response.]
DR. FONTANA: Thank you very much.
DR. SEALE: Drinking with a fire hose.
DR. FONTANA: Pardon?
DR. SEALE: Drinking with a fire hose.
DR. FONTANA: The next area -- is it one presenter for the remaining areas?
MR. SHEMANSKI: Yes. I've got the next four sections.
DR. FONTANA: Okay.
MR. SHEMANSKI: I may need some help, though.
DR. FONTANA: All right.
MR. SHEMANSKI: Good afternoon. My name is Paul Shemanski. I'm with the Electrical Instrumentation and Control Branch, Division of Engineering. I will be making presentations on the four remaining sections; Section 3.12, 3.13, 4.1 and 4.0.
Starting with Section 3.12, which is entitled electrical components. This section is devoted primarily to not EQ cables. Electrical cables are long-lived, passive components that are within scope and subject to an AMR and cables that are associated basically with every plant system.
At Calvert Cliffs, there are approximately 30,000 cables and of the 30,000 cables, 29,000 are non-EQ cables and 1,000 are EQ cables.
Again, this section deals primarily with the non-EQ cables. Because of the large population, BGE decided to treat cables, the non-EQ cables as a commodity and for efficiency, the 29,000 non-EQ cables, they were divided up into six groups, as indicated on the slide.
The first two groups are located in the main steam penetration room. The first group consists of cables and power control servers routed without maintained spacing, whereas the second group consists of cables and power servers which are routed with maintained spacing.
The reason group number two has maintained spacing is that these cables are designed to carry larger currents, so they have to be spaced a certain number of cable diameters away from each other, so that you don't suffer the thermal effects of self-heating, due to ohmic heating.
DR. MILLER: So the spacing requirements are strictly the ohmic heating.
MR. SHEMANSKI: It's the ohmic heating and the spacing is determined by the actual -- I guess they go through and do the thermal calculations and determine how many cable diameters away form each other they must be spaced. It's a function of the cable loading, the current it's carrying.
DR. MILLER: Are any of these cables -- are there any in radiation areas? I notice you have -- I'm looking at the LRA right now and you have a lot of discussion of cables that are in radiation areas and how you're going to handle those through calibration and so forth.
MR. SHEMANSKI: These particular cables are located in the main steam penetration room and I do not believe -- Carl, is that correct? I think they're only subject to thermal.

DR. MILLER: These probably aren't in radiation areas.

MR. SHEMANSKI: I don't believe these are.

MR. YODER: My name is Carl Yoder. Those cables in the first two groups are outside containment. They are in the aux building, not just the main steam pen room, but throughout the aux building.

MR. SHEMANSKI: Now, group three, cables and power servers, those are located in containment and they are subject to synergistic thermal and radiation aging and the max temperature in containment is 120 degrees F.

Group four, cables in the four KV power service, those cables are subject to thermal aging and they are used for the four KV pump motors in the saltwater system.

Group number five, those cables are located in instrumentation service and they are subject to thermal aging resulting from a reduction of insulation resistance.

DR. MILLER: So those are subject to degradation.

MR. SHEMANSKI: Yes, they are. Instrumentation cables tend to be smaller and more susceptible because of their physical dimensions, more susceptible to thermal degradation, and those particular ones, they manage the aging through instrument calibration program. They periodically calibrate the instrumentation circuitry and they can, in essence, tell if they're getting degradation due to calibration errors or whatever -- not calibration errors, but changes in calibration.

DR. MILLER: So the concept -- I'm reading this section right now in the LRA. The concept there is you have -- starting at excessive drifting, for example. You're going to attribute those to cabling or --

MR. SHEMANSKI: You start by doing a root cause analysis and it may lead you to a determination that the cable insulation may be degrading, resulting in the increase in -- or I should say reduction in insulation resistance and that would effect the calibration of the instrumentation circuits.

DR. MILLER: And all those cables are accessible, so they can replace them.

MR. SHEMANSKI: I believe so. And the last group are cable sin the four KV power service. They're also used for the four KV pump motors in the saltwater system, but they're -- well, they looked to see if they were susceptible to a degradation mechanisms called treeing. Treeing is a form -- it's a high voltage induced degradation. It results in kind of a tree-like pattern in the cable insulation and its degradation that provides hollow microchannels in the cable to grow.

And as those microchannels grow, I guess, the cable becomes -- you have changes in the dielectric material, dielectric characteristics of the insulation. However, they did do an ARDI and found that there was no evidence of any treeing in those high voltage cables.

DR. MILLER: And none of those cables -- are those cables in radiation areas?

MR. SHEMANSKI: No. They're in the -- they're used for the four KV pump motors. They are subject to thermal degradation.

DR. MILLER: So the only cables really in the radiation

areas are instrumentation cables. Is that right?

MR. SHEMANSKI: No. There are cables in power service in containment, group three.

DR. MILLER: I'm sorry. You're right.

MR. SHEMANSKI: And those, of course, are subject to synergistic thermal and radiation aging.

DR. MILLER: So how are -- I can probably read it here and find it. How are they going to handle those effects in case -- instrumentation, I can see they're going to do surveillance. On the power service, how are they going to do those, if there is any degradation? Since we know that degradation of instrumentation cables -- I mean, there are different insulators and so forth, I'm certain there are.

MR. SHEMANSKI: Group three was subjected to an ARDI. As a matter of fact, all six groups were subjected to ARDIs and the ARDIs, the age-related degradation inspections, have been completed. Specifically, for group three, BGE is telling us that any power cables that satisfy the following criteria, if they're inside containment, if they use EPR, which is ethylene, propylene, rubber or cross-link polyethylene, if they're not environmentally qualified, which these are non-EQ cables, they're saying that these are considered to be subject to plausible synergistic radiation and thermal aging. So they will -- those are plausible aging mechanisms, so they will periodically have to look and see if they are getting any type of degradation.

DR. MILLER: Is that by visual inspection?

MR. SHEMANSKI: Well, one way. They do have monitors, radiation temperature monitors. They know what the threshold levels are of the cable insulation material. Carl, I believe, wants to amplify.

MR. YODER: I just want to clarify. With regard to those cables we have determined to be subject to plausible aging, except for the instrumentation cables, which will be subject to loop calibrations that include the cables, the rest of those, we've committed to replace.

DR. MILLER: So they're all accessible for replacement, in other words.

MR. YODER: Well, we'll probably end up re-running them. We won't pull all the cables out.

DR. MILLER: So you pull the old ones out and you'll re-route them if you can't route them --

MR. YODER: We normally would not pull an old cable out because it would probably damage surrounding cables. So we'd run new ones.

DR. MILLER: I see.

MR. SHEMANSKI: This particular slide shows the various aging effects which cables are subject to, embrittlement, cracking, reduced mechanical integrity, swelling and so forth, insulation resistance reduction. And we mentioned the ARDI program, which has been completed for these cables.

I also talked about the instrument calibration program.

As a result of our review of these non-EQ cables, we did not identify any open items or license renewal issues.

DR. MILLER: Now, somewhere I saw that, of course, there is

a generic issue 168 on cables. How do we get around that? That's not been fully reconciled yet.

MR. SHEMANSKI: This particular section is on non-EQ cables.

DR. MILLER: That's non-EQ, you're right. I'll wait for that.

MR. SHEMANSKI: My last presentation will be on EQ. 168, GSI-168 is devoted to environmental qualification.

DR. MILLER: We'll wait.

MR. SHEMANSKI: This is not the section, 3.13. This is confusing. Let me explain how we arrived at putting this section in the SER.

If you look in the license renewal rule, EQ appears twice. It appears once under scoping, where the five regulated events are listed, ATWS, fire protection, PTS, so EQ is listed under scoping. Then it appears again in the EQ rule -- I mean, in the renewal rule as a TLAA.

This particular section, when BGE generated their application, they wanted to address the scoping aspect of EQ, which requires that you look at passive, long-lived components. So what they did was they took the EQ master list and they only looked at the long-lived, passive components on the EQ master list, where there may be intended functions of these components that are not managed by the EQ program, and because the EQ program focuses primarily on radiation and temperature. Those are the main parameters.

However, if you look at some of these components, such as the containment penetration assembly, that is subject to general corrosion. Well, that general corrosion is not handled by the EQ program. So BGE identified four components here, the containment penetration assemblies, core exit thermocouples, they're subject to crevice corrosion and pitting, solenoid valves, they're subject to crevice corrosion and pitting, and the reactor level vessel monitoring in core assembly, which is subject to crevice corrosion and pitting.

For those particular aging effects, they identified the following programs. For the specific class of EQ components, the ones I just mentioned, general corrosion, crevice corrosion and pitting, those are handled by the chemistry control program in PEG-7, which I believe is a walkdown type program.

Kapton-unique aging, that one is dealing with the insulated wires on Valcor solenoid valves. It turns out that Kapton, it's not an extruded insulation material. It's sort of wrapped and, as such, it's more susceptible to absorbing moisture and under hot high moisture conditions, hot temperature and high moisture conditions, the Kapton can absorb water and then it becomes very brittle.

It really should only be used in an environment less than 40 percent. So that's sort of a unique aging effect for a particular type of solenoid valve that BGE is using.

There were no open items or confirmatory items or license renewal issues associated with this subset of EQ components that I just discussed.

DR. UHRIG: Are any of the Kapton-unique components used in safety systems?

MR. SHEMANSKI: I believe so. They're used as solenoid valves and I believe the answer is yes, they are in safety-related systems. They are on the EQ master list.

DR. UHRIG: So anything that's EQ would be on a safety system.

MR. SHEMANSKI: Right. Although it is possible, on the EQ master list, there are some non-safety-related components that may have to be qualified. But probably 95 percent of the components on the EQ master list are safety-related electrical components.

DR. MILLER: The idea here is they've already been qualified.

MR. SHEMANSKI: They've already been qualified.

DR. MILLER: Tested at least.

MR. SHEMANSKI: Right. They've been qualified through LOCA testing.

DR. MILLER: And somebody has agreed that a short-term LOCA type test is equivalent to a long-term -- you have the same number of rads over long-term and it's the same number of a short-term.

MR. SHEMANSKI: Well, basically, you're trying to -- in a LOCA chamber, you're trying to simulate LOCA and they go through and make a calculation of what the expected pressure and temperature is. They try to simulate that in the LOCA chamber and then they add in the accident dose that you would expect, typically 150 mega-rads. So it's, in essence, trying to simulate LOCA conditions.

How long you test it in the LOCA chamber is a function of how long the equipment is required to operate post-LOCA, and that varies depending on the plant CLV. Some plants have a 30-day operability time, others go up to, I believe, one year. It's a function of when the plant was licensed.

DR. MILLER: Of course, that's not a synergistic test. Temperature and radiation is not the same thing.

MR. SHEMANSKI: Well, you do get a -- there is a synergistic effect. You get added degradation when you combine radiation and temperature.

DR. MILLER: They just aren't done at the same time.

MR. SHEMANSKI: Right. Are there any additional questions on cables? Because the next presentation will be on TLAAs.

DR. MILLER: The generic issue, are you going to address that here sometime?

MR. SHEMANSKI: Yes. The next presentation --

MR. SOLORIO: Paul, can I interrupt something? Before you go on, Paul. BG&E pointed out to me something related to an earlier presentation the staff has made on Section 3.11. With respect to the electrical commodities, BG&E has changed their commitment to use ARDI as one of their aging management programs and they're going to use electrical penetrations. That was a recent change and the staff is reviewing that against the SER, because it's currently not reflected in the staff's SER.

However, I don't anticipate there being any significant changes, because we're really talking about going to -- the nature of the program probably is going to be very similar and it's probably going

to be even more frequent.

As opposed to a one-time inspection, it's going to be a periodic type of inspection. So I don't see a significant change in that area.

MR. SHEMANSKI: Okay. The next section in the SER, Section 4.1, is the identification of time-limited aging analyses, TLAAs. BGE has identified each TLAA with its aging effect and its disposition, demonstrating that the analyses either remain valid for the period of extended operation, the analyses have been projected through the end of the period of extended operation, or the effects of aging on the intended functions will be adequately managed for the period of extended operation.

In my next presentation, I'll go into a little more detail on EQ, because you haven't heard anything about that yet. However, for the other TLAAs, which appear on this slide and the next slide, this is a total list of TLAAs.

Do you have any specific questions on those? You heard most of the discussion regarding fatigue monitoring program and I believe most of these, if not all, have been covered by previous speakers. So if you do have any specific questions on any of these TLAAs, we have several staff members that probably would be in a better position to answer them.

Basically, what I've given you here is the list of the TLAAs that have been identified by BGE. I'll just run through them one by one. The heat-up and cool-down curves, the aging effect is radiation embrittlement and the aging management program relies on the G and H, 10 CFR 50 Appendices G and H curves, and data from the surveillance capsules.

DR. FONTANA: TLAA involves equipment that whose lifetime originally -- let me see if I understand this properly. It's equipment whose lifetime originally could have gone past 40 years, but if you're going to extend a license, it can go -- the equipment will have to operate beyond what may have been its design life. Is that correct, basically? And you have to analyze that it's going to be able to perform its function during this additional time period, is that correct?

MR. SHEMANSKI: Right.

DR. FONTANA: Now, the analysis then is done, like the heat-up and cool-down curves on radiation embrittlement, the analysis is obviously quantitative. You have models and predictions and that sort of thing.

They're not referenced here. I guess if you look at the BG&E report and you track the references all the way through, they should take you to the models and data and uncertainties and everything else. Is that correct?

MR. SHEMANSKI: Well, they should, yes. Right.

DR. FONTANA: Well, do they?

MR. GRIMES: Dr. Fontana, if I could. The simplest way to describe time-limited aging analysis is basically a design analysis that, in some way, incorporates 40 years in the design calculation. So for example, the PTS analysis has a plant life assumption it. Fatigue

has a certain number of cycles assumed in it.

And this, the aging management aspect of time-limited aging analysis is either that you show that the -- you state the analysis has already been updated for a 60-year life, you -- it either already exists, it has been updated to 60 years, or it will be managed in some way.

DR. FONTANA: Well, how do you know it's any good?

MR. GRIMES: We review the analysis results. We've either done it -- as Barry mentioned earlier, we've already done a safety evaluation related to embrittlement for a 60-year life. In other cases, there are analyses that we've seen before. So by sampling a typical analysis, we have confidence that simply redoing the analysis with a different assumption is all right, or there is an aging management aspect associated. There is a process aspect that we can refer to.

MR. ELLIOT: I'm Barry Elliot. The pressure temperature limits curves are developed from the requirements in Appendix G and the requirements in Appendix H is the surveillance program. That's just to confirm that the embrittlement we used for the curve is what we think it is.

Now, the embrittlement -- the non-embrittled portion of the analysis is in the ASME code. It's a specified way of calculating pressure temperature limits. The part that's age-related degradation is the embrittlement portion and that is -- we have regulatory guide, Reg Guide 1.99, Rev 2, which describes how you are to calculate the amount of embrittlement which goes into these pressure temperature limits. What we do is if a new pressure temperature limit comes in, we review the surveillance data, we review the methodology of calculating the embrittlement to make sure it complies with what's in the regulatory guide.

So this is time-limited aging. It happens to be, for this particular plant, they gave us a 48 effective full power year curve already and so they've already done -- for the equivalent fluence of 48 effective full power years, for Unit 1. For Unit 2, I think they have only a 30 effective full power years.

So sometime in the future, before 30 effective full power years, they have to give us another curve that applies to 48 effective full power years. But they would be following the guidance in the -- the requirements of Appendices G and H and the regulatory guidance in Reg Guide 1.99 to calculate those curves.

DR. FONTANA: Okay. Thanks.

MR. SHEMANSKI: Okay. The next two TLAAs involve fatigue analysis for RCS piping, steam generator pressurizer, pressurizer auxiliary spray line, and pressurizer surge line. The next one is the fatigue analysis for main steam supply lines for turbine-driven aux feed pumps, and those are both managed by the fatigue monitoring program.

In addition, the next TLAA is also managed by the fatigue monitoring program, fatigue analysis for the containment liner plate. The next TLAA is the pre-stress loss calculations on containment tendons. That particular TLAA has been deferred by Baltimore Gas & Electric to the year 2012.

Another TLAA is the spent fuel pool criticality calculation,

the aging effect is loss of neutron absorption and the coupon surveillance program is used as the aging management program for that.

DR. FONTANA: I'm just curious. How do you go about measuring the tension in the tendon?

MR. SHEMANSKI: They've got a lift-off test which is in the tech specs and I forget the parameter, 2000 KIPS or some -- I don't recall the exact number, but they have kind of a jack and they're able to measure the lift-off force with the tendons, and that's really not my area.

DR. FONTANA: Okay.

MR. SOLORIO: The NRC staff reviewer who evaluated that isn't here at the moment, but I believe someone from BG&E has some information they can provide.

DR. FONTANA: I'm sure you know how to do it. I was just curious.

MR. WARD: I'm Don Ward. It's sort of backing out of the way they're installed initially. The tendons are installed with shims under both ends, so that you wind up with stretching the wire in order to get the tension in there.

When you do the lift-off test, you put a ram back on one end or a jack, a thousand-ton -- I'm sorry -- a 500-ton jack, pull on it, and measure the force. There are gauges on the jack that you can measure the force with.

DR. FONTANA: Five hundred ton jack.

MR. WARD: Yes. They carry about 700,000 pounds each.

DR. FONTANA: Thanks.

DR. SHACK: What does it mean when the program is deferred to 2012?

MR. PATNAIK: This is Pat Patnaik. What we got from the applicant, that they would provide us the curves, the loss of stress, pre-stress loss, on the tendons, calculated to the new values. That will be covered in the tech specs. Those are in the tech specs.

MR. WARD: Don Ward again. The part that was in the tech specs, that you will now remember being in the tech specs, was recently moved to chapter 15 of the FSAR, but it's the same sort of thing. It's these curves plot on semilog paper as a straight line. We were just looking to see if there are any nuances and so it's being deferred a bit, particularly until we decide what we're doing with the vertical tendons.

MR. SOLORIO: This is Dave Solorio. I just wanted to point out also that there is an open item associated with this. Page 109.

MR. SHEMANSKI: It's open item 4.1.3-2, deferral of the re-calculation of loss of pre-stress on containment tendons, to the year 2000. Since we're on open items.

There is also an open item on the addition of the upper shelf energy evaluation as a TLAA. The staff has concluded that this is a TLAA and should be treated as such. The third open item is the addition of metal fatigue of B-31-7 Class 2 and Class 3 piping as a TLAA. Apparently, BGE did not -- I'm sorry -- BGE did consider the number of cycles in the evaluation of Class 2 and Class 3 piping.

Therefore, the staff feels that this is a TLAA, should be

treated as a TLAA. There is one confirmatory item regarding documentation of containment liner plate fatigue analysis. Basically, BGE needs to document the evaluation which demonstrates that the current analysis remains valid for the period of extended operation.

We list one license renewal issue, 98-0048, elevated temperature of pre-stress in tendons. This, I believe, was previously discussed in Section 3.10 of the staff SER on building structures.

Are there any additional questions regarding TLAAs?

[No response.]

DR. FONTANA: I guess not.

MR. SHEMANSKI: If not, then I'll go to the final TLAA, which is EQ, environment qualification of electrical equipment. BGE identified the 10 CFR 50.49 program, that's the EQ rule, 50.49. BGE identified that as a TLAA for license renewal.

Now, it's important to note that when the staff evaluated the BGE TLAA for EQ, we focused on the program elements and process, and I will repeat that again. We focused on the program elements and process provided by BGE.

They are using standard approved EQ methodology and acceptance criteria in accordance with the 10 CFR 50.49 EQ rule.

Basically, the way BGE is treating it, for all of the long-lived active and passive, this TLAA is unique, it includes -- this is the only TLAA, the only place in the application you'll see where we have active components in license renewal.

It just so happens that the EQ rule 50.49, when you look the EQ master list, it consists of active and passive components.

DR. MILLER: Did they do that just for convenience?

MR. SHEMANSKI: No. I mean, that was the way the EQ rule initially was developed. You had to list or include all of the electrical components that --

DR. MILLER: All safety-related.

MR. SHEMANSKI: All safety-related electrical components that are, number one, subjected to a LOCA or main steam line break or high energy line break; that is, subjected to a harsh environment, and then required to mitigate that particular DBE.

You look at the list, it includes, as you could see, motors, transmitters, pressure switches, all of which are active. But for this particular TLAA, we do include both active and passive long-lived components.

DR. MILLER: But it wasn't required to do that. Is it required to do that by the rule?

MR. SHEMANSKI: Which rule are you referring to?

DR. MILLER: By the rule, the license renewal rule.

MR. SHEMANSKI: The focus of the Part 54 rule is on long-lived --

DR. MILLER: Passive.

MR. SHEMANSKI: -- passive components. However, it does list five regulated events. It lists -- in paragraph 54.3, it lists fire protection EQ, ATWS, PTS, and station blackout. And by picking up the EQ rule, you automatically pick up the EQ rule master list, which has active components.

DR. MILLER: So by including EQ, you automatically pick it up.

MR. SHEMANSKI: You automatically pick these up. So there -- and basically the aging management program for EQ is the 50.49 program.

DR. MILLER: In a way, the rule 54 picks up through EQ the active components.

MR. SHEMANSKI: Right.

DR. MILLER: The EQ program then covers you.

MR. SHEMANSKI: That's correct.

DR. MILLER: That's a simple way to put it.

MR. SHEMANSKI: And the way BGE approaches the qualification of these particular components is prior to the end of an equipment's qualified life, the equipment will be replaced, unless it can be -- unless the qualified life can be extended through reevaluation, primarily re-analysis. So they tell us that sufficiently in advance, prior to the expiration of a component's qualified life, they will go through and determine whether or not that component needs to be replaced or whether or not they could extend the qualified life based on re-analysis or some type of reevaluation.

Now, we reviewed the methodology that BGE is using in their current EQ program, and keep in mind that they do have an approved 50.49 program. They've got an SER issued by the staff in the mid '80s which finds their EQ program in compliance with 50.49. So they're solid for the first 40 years.

And as equipments on the EQ master list approach the end of their qualified life, they will be re-assessed ten years from now just as they are today. They will be using the same methodology.

So we looked at how they extend their component qualified life and we evaluated or looked at the acceptance criteria they apply, what type of corrective actions they use, how they go about refurbishing.

We looked very closely at how they would be applying re-analysis, how they treat the thermal and radiation environments, and what effect any plant environmental changes would have on the qualification status. So we took a pretty in-depth look at their existing program, basically doing a process type evaluation, and are satisfied that 50.49 is an acceptable aging management program.

DR. MILLER: So 50.49 covers everything that we've talked about all day today.

MR. SHEMANSKI: Well, 50.49 focuses primarily on electrical components in a harsh environment. The key stressors they are subjected to are thermal and radiation and if they happen to be subject to spray from the ECCS system, caustic spray, then, of course, they --

DR. MILLER: Boron -- boric spray.

MR. SHEMANSKI: Right, they've got to simulate that in the LOCA chamber, that is part of the qualification process.

This slide shows the aging effects due to thermal and radiation primarily, and those aging effects are managed by the qualification process, which is utilized in the 50.49 program.

DR. MILLER: So were all the things like all the sensors and

so forth excluded and all the rest of the program, now we've got pressure and flow transmitters all included at this point for these -- if they're EQ.

MR. SHEMANSKI: Right.

DR. MILLER: And we assume an environmental qualification covers all the issues we talked about.

MR. SHEMANSKI: Well, it does not cover things like crevice corrosion or general corrosion. It turns out that some of these components on here, electrical penetration assemblies, solenoid valves, they have a license renewal intended function, for example, to maintain pressure boundary and that particular function is really not -- it's not evaluated in the EQ program. That was why BGE, when I went through Section 3.13, they looked to see are there -- they went through these -- this entire EQ master list and they said are there any of these components that have intended functions such as pressure boundary that are not covered by the EQ program, and they did find four, I believe.

DR. MILLER: Solenoid valves were addressed separately in there.

MR. SHEMANSKI: Right. So they are subject to general corrosion or pitting and, of course, those aging effects are not managed by the EQ program, but they're managed by other programs, I believe the chemistry control program.

So the bottom line is I think they've got all the -- all of the plausible aging effects have a management program.

DR. MILLER: In that list, there's, of course, a whole bunch of passive components. They've already been covered under the other program, as well as this one.

MR. SHEMANSKI: Right.

DR. MILLER: So the only questionable one would be components such as flow transmitters and pressure transmitters and level transmitters. Those might be the only ones that might be falling through the crack, so to speak.

MR. SHEMANSKI: I don't believe they have fallen through the crack, because I don't think those particular ones have any license renewal intended functions that are not being managed by the EQ program.

DR. MILLER: I'm not saying they did. I'm saying they could have.

MR. SHEMANSKI: They could have. We did look and I don't believe --

DR. MILLER: Based on the fact that we spent maybe five or ten hours on this, everybody else has spent many more than that. I just looked at it from a superficial viewpoint and I would say, gee, did we cover everything of those active components that weren't covered under all the other programs, does EQ cover everything under those.

MR. GRIMES: Dr. Miller, I looked at --

DR. MILLER: Am I asking a question that makes any sense?

MR. GRIMES: Yes, and I'd like to attack your question in a slightly different way.

DR. MILLER: Don't attack it. Address.

MR. GRIMES: Address. Okay. First of all, I want to clarify, time-limited aging analysis don't care about the license

renewal scope. They're a time-limited aging analysis. There is a qualified life. EQ just happens to be the biggest qualified life question we've tackled and for -- to the extent that managing the environmental qualification time-limited aging analysis relies upon the 50.49 program, regardless of whether or not you've got a piece of equipment that's active, passive, long-lived, short-lived, whatever it is, if it's got an EQ qualified life of a year, 40 years or 1,000 years, the 50.49 process will sort that out.

To get back to your other question about what do we do with GSI-168, to the extent that information comes out of that research that challenges the qualified life of any particular cable, then that same compliance with 50.59 process, about making decisions about replacing, refurbishing, re-analyzing or re-testing, we rely on that process to address GSI-168 until the research identifies something different to do.

But to the extent that EQ stuff is also captured as -- in 4.13 of the -- I'm sorry -- 3.13 of the safety evaluation, where we also look at it from the standpoint of are there other aging effects that are not explicitly addressed by this qualified life process, like crevice corrosion or fatigue or other thing, then we address that specifically for passive components.

For active components, all of those things are excluded for the same reason we excluded active equipment and that's basically we're looking at reliability under the maintenance program as the means to manage aging effects for active components.

DR. MILLER: I think I'm visually seeing everything fitting together. I'm now seeing the cracks are closing.

MR. GRIMES: The EQ was particularly troublesome for us, as well, because even though it's a well established and well regulated program, it's got this overlapping area of responsibility and so that's why we ended up with one section of the safety evaluation that treats aging effects and aging management programs and then time-limited aging analysis also has an aging management aspect of it, as well, but it really gets back to the process question.

MR. SHEMANSKI: My last slide, there are no open items or no confirmatory items regarding EQ. However, we did have one license renewal issue, 98-0014, which basically asked the question whether or not 10 CFR 50.49 is an adequate aging management program under the license renewal rule. And basically, the answer is yes, and we concluded in the BGE SER that 10 CFR 50.49 is an acceptable aging management program under 10 CFR 54.21.

MR. GRIMES: Paul, if I may. I would like to clarify that this particular generic renewal issue has now blossomed into what we call the credit for existing programs issue, which was forwarded to the Commission and I believe that the ACRS received a copy when we forwarded the NEI letter.

We're developing a Commission paper that addresses the extent to which the staff can conduct a license renewal review without challenging the adequacy of these existing programs.

So you will be hearing more about that, but for the purpose of this review, we challenged the existing programs. We went digging into, for example, environmental qualification and compliance with

50.49. The means of compliance as it relates to managing aging.

So you will be hearing some more about that issue, but it's really more relevant to treating future applications.

DR. FONTANA: The future applications, these license renewal issues that are resolved now, are they assumed to be resolved for all future applications?

MR. GRIMES: To the extent that we would add guidance to the standard review plan or that NEI would add guidance to the NEI 95-10 guide on preparing an application, yes, we consider them resolved for future applications, too.

DR. FONTANA: We're a little overdue on our break. Any questions on this area here?

MR. WESSMAN: Before we go on a break. I'm Dick Wessman, with the staff. A minor housekeeping item. On page 108 of the viewgraphs, we had an erroneous entry there and I wanted to clarify that. If you look at that, you will see a couple of entries, one of them dealing with fatigue analysis for the containment liner and another one at the bottom dealing with Class 2 and 3 piping.

Those two activities are not covered by the fatigue monitoring program, per se, but they are addressed by analysis activities done by the applicant.

DR. FONTANA: Thank you.

MR. WESSMAN: Yes, sir. That's all.

DR. FONTANA: Let's take a break. Let's see. When we come back, we'd like to discuss what will be presented at the May full ACRS meeting, some topics for an ACRS interim letter, and possibly what would be appropriate for additional staff presentations and maybe for future meetings. So you all may want to be giving some thought to those items.

So let's come back at 20 of.

[Recess.]

DR. FONTANA: The meeting will come back into session. The first thing that we would like to discuss with you is what should be included in a presentation for the full ACRS meeting the first week in May. You have an hour and a half, and that's on the first day, I think, Wednesday. Will you be making most of the presentation?

MR. GRIMES: Were you addressing me personally or the staff?

DR. FONTANA: You.

MR. GRIMES: We'll do -- actually, we do almost anything you want. We can do a summary overview. We can just have a very high level with Dave giving his overview presentation and maybe putting together some summaries or if there are particular topic areas, Mr. Wessman was graciously supporting us and we could get particular staff to come talk about topical interests.

DR. FONTANA: Well, the full committee I don't believe has received a presentation from you in this area, in my memory at least, I don't think. So I think it's probably appropriate to start from the top and give a -- because I'm sure that two or three of them that are not here and some that are here don't understand the whole philosophy of this license renewal, which is really rather esoteric, just coming off the street and listening to it.

So I think an overview of the philosophy basically that you

as the staff are working within the constraints of Part 54 and whereas we on the committee aren't necessarily. But with regard to what you're doing, I think you probably should quickly overview what Part 54 is constraining you to do.

DR. SEALE: How long do we have?

DR. FONTANA: An hour and a half. But I think maybe taking about ten minutes to get everybody on the same page is probably going to be worthwhile, because questions that are going to arise are how do you determine what's in scope and what's not in scope, and the concept of TLAA is rather esoteric, so you may want to say -- just like you said about 20 minutes ago, perfect.

Then the area of issues, I'm sure there is going to be some confusion about what are generic license renewal issues compared to the other list of GSIs, and you may want to identify what the difference is, and how you -- the basis for the prioritization of the issues, the fact we now have 105 of them, when I think there's --

MR. GRIMES: It's 109.

DR. FONTANA: It's 109, and I forget how many are on the priority one list. In fact, you would allow some issues to go into --

DR. SEALE: Sixty years.

DR. FONTANA: To go beyond the end of the current license, and I'm sure you're going to get asked about that.

With respect to the SER, I think we'd like an overview of it, relating most of the key agreements and what the key issues left are and what the key confirmatory things are. There aren't many of them left, as far as I could see.

DR. SEALE: Could we get some words from BG&E?

MR. DOROSHUK: Yes, sir, we could support that. Is there any specific area?

DR. SEALE: Well, in your presentation you made, of course, there's a lot of it that's background and all, but the material and the scope, your perception of what the scope is, and then the IPA process you went through, and then maybe a summary of some sort.

MR. DOROSHUK: Yes, sir.

DR. SEALE: I think that would be very helpful to the committee, because it -- I won't call it a bottoms-up approach, but it is the applicant now working with the process as opposed to the regulator's perception of what the process ought to come up with, and I think that's very important.

DR. FONTANA: Those two diagrams. You have the IPA flow diagram, I think that's useful and very valuable.

DR. SEALE: Yes.

MR. GRIMES: You could start about the IPA flow diagram and end up about the last pie chart, and it's that chunk in the middle there.

DR. FONTANA: How much time do you think BG&E should have out of this hour and a half?

DR. UHRIG: Twenty, 30 minutes.

DR. SEALE: Yes. Something like that.

DR. FONTANA: Something like that. And I guess you will start it, the staff will start it, and you determine between yourselves

where to break into it, I guess.

MR. WESSMAN: I think it would be constructive for the staff to do that introduction and overview of the philosophy, then go to BG&E with their discussion of how they did the submittal and then come back to our SER and we'll pick the specifics that you want us to. That's how to handle three 30-minute segments, for lack of a better term.

DR. SEALE: Exactly. Recognizing that you're going to get interruptions.

MR. WESSMAN: Of course. Especially by people who are not here. At least we know who they are.

DR. FONTANA: Any additional thoughts on what ought to be covered in the meeting?

DR. SEALE: I could facetiously say that if you don't want to get too many interruptions, you might not say anything about fire protection, but I guess that --

DR. FONTANA: Or risk-based.

MR. WESSMAN: That's right, George will be here. We could use, as a clue from you all, as to the specific areas that you think, as we try to characterize the SER, that you want us to spend time on. I think there's been a lot of interest in fatigue and we probably need to offer that up. But if you could give us some other specific areas that you think are areas of interest.

DR. MILLER: I'm not certain this -- this is something I need to look at for my own edification, but I'd like to have more information on the environmental qualification program and how that all fits together, the things we hit near the end.

Now, again, that may not be generic enough for the committee, though.

DR. FONTANA: Well, first of all, you want to get --

DR. SEALE: We're down to an hour here, guys.

DR. MILLER: I know, that's what I say, an hour and a half, we won't have enough time for any of these specialty areas.

DR. FONTANA: When you get to the SER, an important idea to get across, whichever way you do it, is the extreme depth. The thing was actually exhausting to --

DR. SEALE: I think the run-through from the first day viewgraphs are a good way to state it. Your presentation, basically.

DR. KRESS: David's.

DR. SEALE: Yes. Then the question is do you try to cherry-pick somewhere through the rest of the 110.

DR. MILLER: Certainly, we've got 30 minutes to go through the other 110 slides, and which ones are we going to pick.

DR. SHACK: You'll vote for EQ, I'll vote for Barry's part, and everybody will pick the part that interests them.

DR. KRESS: I would pick the steam generators.

DR. SEALE: I think just to get across the idea that you're putting a very heavy reliance on inspection, that that's really the tool that this process, this whole process relies on.

DR. UHRIG: I also think it would be useful to convey the concept that this is really using existing programs to the maximum extent possible, with modifications where necessary. Only when this was

not appropriate did you go to new programs.

DR. FONTANA: I guess you ought to do something for common aging management programs.

DR. SEALE: Yes.

DR. FONTANA: This category. Because I think that's important.

DR. UHRIG: There were some numbers given about what percentage of the -- how many new procedures, how many existing procedures, how many modified procedures. I don't remember the exact numbers, but it was --

MR. GRIMES: Out of the 430, there were 329 --

DR. UHRIG: Those kind of numbers. I think that gives you a picture.

MR. GRIMES: Yes, 11 new, 101 modified, something like that.

MR. DOROSHUK: We'll make sure we have those slides for that particular part of the presentation.

DR. MILLER: I guess we're looking at kind of a condensed version of what we heard yesterday, right? Mostly.

DR. FONTANA: Bill Shack, do you think one of the things that should be touched on is the Section 3.2, vessels internals and reactor coolant system? That's what Barry Elliot covered.

DR. SHACK: Well, after you go through the big overview, I don't know whether we should -- the 3.1, the aging management review of the common management programs maybe should be the big sweep. Even there, I don't think we -- you know, we can't go through it in the detail that you went here, but somehow you've got to, out of this thing, grab that chunk out.

I think that will probably chew up --

DR. MILLER: You've got an hour and a half right there.

DR. SHACK: -- most of the time. Between those two presentations, it's sort of gone.

DR. FONTANA: It sounds like we really can't get into much of the specific areas.

DR. SHACK: I don't see how we can get into the specific areas.

DR. FONTANA: Unless the question pops up.

MR. DUDLEY: There is an alternative. For the three people who are not here, provide them a copy of the slides, where they can see what programs are or what systems are evaluated in each chapter.

DR. KRESS: Those three people will have also read part of the SER and they can come prepared to ask questions. So we'll make it known that if they have an issue with some of that SER, that they need to ask.

DR. UHRIG: But you could easily send them the slides that were used today.

MR. SOLORIO: I would like to ask that if you'd let us know what areas they've read, so we can prepare the staff.

MR. WESSMAN: Yes. I hate to muster 20 people over here, even though it's only an hour and a half. If there is any way we can focus it down to a smaller number of key players. They're busy working on Oconee.

DR. FONTANA: It seems to me that you three guys will be able to cover it at the level we're talking about.

DR. SEALE: Why don't we ask them who they can best do -- I mean, the rest of the guys.

MR. GRIMES: I'd also like to suggest you -- we've got a head start this time. To the extent that two and a half of us anyhow can try and get through as many of the common programs and the basic stuff and address broad questions about aging management, as much of that as we could accomplish in an hour and a half we're going to have next week, we could do that, and then we've still got open items to resolve. We could -- we're going to come back to the committee at least once more.

So we could -- maybe we could get a sense next week about what particular areas you'd like to explore further and we could just make a commitment that we'll address those in a future meeting.

To the extent that we can dispose of as much as you can dispose of and focus down on particular areas of interest.

DR. UHRIG: I think in the preparation of the letter, this will be brought to a focus.

DR. FONTANA: Will that give you enough to go on?

MR. GRIMES: We're going to -- in the hour and a half, we're going to devote about 30 minutes to a broad overview of Part 54, terminology, the basic elements, what are the time-limited aging analysis, basically a day's presentation in a half an hour for BG&E, and then a half-hour for the safety evaluation overview, which means three 15-minute prepared presentations. Does that pretty well cover it?

DR. FONTANA: So that the need for additional staff presentations, I think we're saying we will need them, but what's going to be included probably will come out of the things that are not going to be covered next week, right?

MR. GRIMES: Right.

DR. FONTANA: So these guys can work up --

MR. GRIMES: We'll make commitments next week to address particular questions and basically frame an agenda for a future meeting.

MR. WESSMAN: We can bring a few of the key people. I think Stephanie Coffin did a lot of work on the ARDI and we'll have her here and that may eliminate some of that area of questioning. So it isn't like it will just be the three of us, but I just don't want to muster all 20.

DR. FONTANA: Any additional ideas, questions? No? If not, are we done?

DR. SEALE: I think so.

DR. FONTANA: I'd like to thank the staff and BG&E. These were really well organized response of talks, they were to the point, good presentations. They reflect a tremendous amount of work and we appreciate the considerable amount of work you did preparing for this meeting, which I'm sure is significant, particularly considering all the other things you've got to do.

So, again, thank you very much, on behalf of the committee, the subcommittee. We appreciate it, and we'll see you next week.

This meeting is over. [Whereupon, at 2:58 p.m., the meeting was concluded]